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June 27, 2023

Steve Kahl  
Executive Secretary/Director of Administration  
North Dakota Public Service Commission  
State Capitol - 600 East Boulevard  
Bismarck, ND 58505-0480

**RE: Otter Tail Power Company's 2023 Annual Report**

Dear Mr. Kahl:

Enclosed is Otter Tail Power Company's (Otter Tail's) 2022 Annual Report for North Dakota. As in past years, I am enclosing a copy of Otter Tail Corporation's 2022 Annual Report to Shareholders and SEC Form 10-K for Otter Tail Corporation and Otter Tail's 2022 FERC FORM No. 1. I am also forwarding an electronic copy of the North Dakota Annual Report in .PDF format by email to you at [ndpsc@nd.gov](mailto:ndpsc@nd.gov).

Pages 1-3 reflect operating statement, rate base, and capital structure values which include Otter Tail's current base rate recoveries as well as recoveries through Otter Tail's renewable, transmission, and generation cost recovery riders on an actual, un-normalized basis. Pages 4-6 reflect the same information on a normalized basis to adjust for the impacts of anomalous items, including weather. Otter Tail's actual 2022 earnings reflected a return on equity (ROE) of 8.73 percent. As shown on page 5 of the attached report, Otter Tail's normalized 2022 results reflected an 8.02 percent ROE.

Additionally enclosed is a Trade Secret assessment of the annual impact from the Super Large General Service Tariff Electric Rate Schedule Section 10.06 (SLGS) customer for calendar year 2022 pursuant to discussions with both the North Dakota Public Service Commission and Commission staff at the time the SLGS tariff was established and approved by the Commission. In accordance with N.D. Admin. Code § 69-02-09-02, an Application for Trade Secret Protection is being provided along with a single copy of the trade secret version of the Application and supporting testimony in a sealed envelope marked **PROTECTED INFORMATION – PRIVATE**.

- 1 PU-23-249 Filed 06/27/2023 Pages: 281  
2022 Annual Report, Shareholders Report, and FERC Financial Report for North Dakota - redacted  
Otter Tail Power Company

Mr. Kahl  
June 27, 2023  
Page 2

If you have questions on the information provided, do not hesitate to contact me at (218) 739-8282 or [cbyrnes@otpc.com](mailto:cbyrnes@otpc.com).

Sincerely,

*/s/ CHRIS BYRNES*  
Chris Byrnes  
Supervisor, Regulatory Analysis  
Regulatory Economics

vjm  
Enclosures  
By electronic service and First Class mail

ANNUAL REPORT  
OF  
**OTTER TAIL POWER COMPANY**  
TO THE  
PUBLIC SERVICE COMMISSION OF NORTH DAKOTA  
FOR THE  
YEAR ENDED DECEMBER 31, 2022

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Otter Tail Power Company  
2022 North Dakota Annual Report

Operating Statement - With All Riders, Un-Normalized

	(A)	(B)	(C)	(D)	(E)	
Line No.	2022 Total Company	2022 North Dakota	ND Percent (B / A)	2021 North Dakota	Annual Change (E-D / D)	
	<b>Operating Revenues:</b>					
1	Residential	145,805,508	66,972,964	45.93%	61,630,604	8.67%
2	Small Commercial and Industri	108,019,293	51,999,326	48.14%	46,851,028	10.99%
3	Large Commercial and Industri	209,428,214	68,862,349	32.88%	43,232,903	59.28%
4	Other Retail	8,192,214	3,356,711	40.97%	3,194,127	5.09%
5	Total Retail Revenue	471,445,230	191,191,350	40.55%	154,908,662	23.42%
6	Other Electric Revenue	74,907,477	18,158,019	24.24%	10,965,091	65.60%
7	Total Revenue	546,352,707	209,349,368	38.32%	165,873,754	26.21%
	<b>Operating Expenses:</b>					
8	Production Expenses	202,179,656	82,768,999	40.94%	53,028,831	56.08%
9	Transmission Expenses	37,477,229	14,387,811	38.39%	12,118,883	18.72%
10	Distribution Expenses	17,303,680	7,838,847	45.30%	7,664,469	2.28%
11	Customer Accounting Expenses	14,027,785	6,186,536	44.10%	5,445,105	13.62%
12	Customer Service and Information Expens	10,866,633	1,168,276	10.75%	1,101,255	6.09%
13	Sales Expenses	526,191	41,797	7.94%	30,779	35.80%
14	Administration and General Expenses	50,531,612	20,082,182	39.74%	15,415,791	30.27%
15	Charitable Contributions	0	0	N/A	0	N/A
16	Depreciation Expense	68,140,836	26,709,167	39.20%	24,841,693	7.52%
17	General Taxes	17,733,835	6,464,014	36.45%	5,943,109	8.76%
18	Total Operating Expenses	418,787,458	165,647,629	39.55%	125,589,916	31.90%
19	Net Operating Income Before Income Taxes	127,565,249	43,701,739	34.26%	40,283,838	8.48%
	<b>Income Tax Expense:</b>					
20	Investment Tax Credit	(5,618,608)	(2,295,960)	40.86%	(1,999,708)	14.81%
21	Deferred Income Taxes	24,697,935	8,674,492	35.12%	6,958,698	24.66%
22	Income Taxes	(409,533)	0	0.00%	0	202.32%
23	Total Income Tax Expense	18,669,794	6,378,533	34.16%	4,958,990	28.63%
24	Net Regulated Earnings	108,895,455	37,323,207	34.27%	35,324,848	5.66%

Otter Tail Power Company  
2022 North Dakota Annual Report

Rate Base - With All Riders, Un-Normalized

	(A)	(B)	(C)	(D)	(E)	
Line No.	2022 Total Company	2022 North Dakota	ND % (B / A)	2021 North Dakota	Annual Change (B-D / D)	
1	Plant in Service	2,808,691,578	1,041,850,025	37.09%	905,801,146	15.02%
2	Net Capitalized Items - Big Stone Plant			0.00%		0.00%
3	Accumulated Depreciation	(964,408,888)	(391,231,179)	40.57%	(343,292,174)	13.96%
4	Net Plant in Service	1,844,282,690	650,618,846	35.28%	562,508,972	15.66%
5	Plant Held for Future Use	29,657	12,897	43.49%	12,675	1.75%
6	Construction Work in Progress	118,508,484	7,674,957	6.48%	9,485,424	-19.09%
7	Materials and Supplies	29,231,708	12,184,922	41.68%	9,756,242	24.89%
8	Fuel Stocks	10,354,598	4,092,023	39.52%	2,975,569	37.52%
9	Prepayments	26,027,563	9,181,902	35.28%	1,802,361	409.44%
10	Customer Advances	(1,622,191)	(572,270)	35.28%	(522,734)	9.48%
11	Cash Working Capital	7,326,698	2,654,567	36.23%	5,664,250	-53.13%
12	Accumulated Deferred Income Taxes	(321,704,219)	(128,524,052)	39.95%	(117,184,911)	9.68%
13	Total Average Rate Base	<u>1,712,434,988</u>	<u>557,323,792</u>	<u>32.55%</u>	<u>474,497,848</u>	<u>17.46%</u>
<b>ACTUAL</b>						
14	Rate of Return on Average Rate Base (page 1, Line 24 /line 13)	6.36%	6.70%			
15	Less: Weighted Cost of Ltd (Page 3, line 1 (D))	2.02%	2.02%			
16	Weighted Cost of Pref. Stock (Page 3 line 2 (D))	<u>0.00%</u>	<u>0.00%</u>			
17	Weighted Return on Equity	4.34%	4.68%			
18	% of Equity to Capital Structure (Page 3, line 3 (B))	<u>53.59%</u>	<u>53.59%</u>			
19	Return on Equity (Page 3, line 3 (C))	<u>8.10%</u>	<u>8.73%</u>			

Otter Tail Power Company  
2022 North Dakota Annual Report

Average Weighted Cost of Capital - With All Riders, Un-Normalized

		(A)	(B)	(C)	(D)
Line No.	Description	2022 Total	Ratio	Cost	Weighted Cost
1	Long Term Debt	752,990,671	46.41%	4.35%	2.02%
2	Preferred Equity	0	0.00%	0.00%	0.00%
3	Common Equity	869,346,098	53.59%	8.73%	4.68%
4	Total	1,622,336,769	100.00%		6.70%

Otter Tail Power Company  
2022 North Dakota Annual Report

Operating Statement - With All Riders, Normalized

	(A)	(B)	(C)	(D)	(E)	
Line No.	2022 Total Company	2022 North Dakota	N. D. % (B / A)	2021 North Dakota	Annual Change (B-D / D)	
	<b>Operating Revenues:</b>					
1	Residential	141,144,127	64,462,698	45.67%	57,520,245	12.07%
2	Small Commercial and Industri	104,891,447	50,176,769	47.84%	58,612,154	-14.39%
3	Large Commercial and Industri	208,628,819	68,573,006	32.87%	34,890,079	96.54%
4	Other Retail	8,141,673	3,337,009	40.99%	3,126,632	6.73%
5	Total Retail Revenue	462,806,066	186,549,483	40.31%	154,149,110	21.02%
6	Other Electric Revenue	74,907,477	18,158,019	24.24%	10,965,091	65.60%
7	Total Revenue	537,713,544	204,707,501	38.07%	165,114,201	23.98%
	<b>Operating Expenses:</b>					
8	Production Expenses	197,795,331	80,952,165	40.93%	53,156,379	52.29%
9	Transmission Expenses	37,477,229	14,387,811	38.39%	12,118,883	18.72%
10	Distribution Expenses	17,303,680	7,838,847	45.30%	7,664,469	2.28%
11	Customer Accounting Expenses	14,027,785	6,186,536	44.10%	5,445,105	13.62%
12	Customer Service and Information Expens	10,866,633	1,168,276	10.75%	1,101,255	6.09%
13	Sales Expenses	526,191	41,797	7.94%	30,779	35.80%
14	Administration and General Expenses	50,531,612	20,082,182	39.74%	15,415,791	30.27%
15	Charitable Contributions	0	0	N/A	0	N/A
16	Depreciation Expense	68,140,836	26,709,167	39.20%	24,841,693	7.52%
17	General Taxes	17,733,835	6,464,014	36.45%	5,943,109	8.76%
18	Total Operating Expenses	414,403,133	163,830,794	39.53%	125,717,464	30.32%
19	Net Operating Income Before Income Taxes	123,310,411	40,876,707	33.15%	39,396,737	3.76%
	<b>Income Tax Expenses</b>					
20	Investment Tax Credit	(5,618,608)	(2,295,960)	40.86%	(1,999,708)	14.81%
21	Deferred Income Taxes	23,632,327	7,985,656	33.79%	6,741,991	18.45%
22	Income Taxes	(430,020)	0	0.00%	0	441.97%
23	Total Income Tax Expense	17,583,699	5,689,696	32.36%	4,742,283	19.98%
24	Net Regulated Earnings	105,726,712	35,187,011	33.28%	34,654,454	1.54%

Otter Tail Power Company  
2022 North Dakota Annual Report

Rate Base - With All Riders, Normalized

Line No.	Description	(A)	(B)	(C)	(D)	(E)
		2022 Total Company	2022 North Dakota	N. D. % (B / A)	2021 North Dakota	Annual Change (B-D / D)
1	Plant in Service	2,808,691,578	1,041,850,025	37.09%	905,801,146	15.02%
2	Net Capitalized Items - Big Stone Plant			0.00%		0.00%
3	Accumulated Depreciation	<u>(964,408,888)</u>	<u>(391,231,179)</u>	40.57%	<u>(343,292,174)</u>	13.96%
4	Net Plant in Service	1,844,282,690	650,618,846	35.28%	562,508,972	15.66%
5	Plant Held for Future Use	29,657	12,897	43.49%	12,675	1.75%
6	Construction Work in Progress	118,508,484	7,674,957	6.48%	9,485,424	-19.09%
7	Materials and Supplies	29,231,708	12,184,922	41.68%	9,756,242	24.89%
8	Fuel Stocks	10,354,598	4,092,023	39.52%	2,975,569	37.52%
9	Prepayments	26,027,563	9,181,902	35.28%	1,802,361	409.44%
10	Customer Advances	(1,622,191)	(572,270)	35.28%	(522,734)	9.48%
11	Cash Working Capital	7,071,458	2,530,836	35.79%	5,704,680	-55.64%
12	Accumulated Deferred Income Taxes	<u>(321,704,219)</u>	<u>(128,524,052)</u>	39.95%	<u>(117,184,911)</u>	9.68%
13	Total Average Rate Base	<u>1,712,179,747</u>	<u>557,200,061</u>	32.54%	<u>474,538,278</u>	17.42%
<b>ACTUAL</b>						
14	Rate of Return on Average Rate Base (page 4, Line 24 /line 13)		6.17%	6.31%		
15	Less: Weighted Cost of Ltd (Page 6, line 1 (D))		2.02%	2.02%		
16	Weighted Cost of Pref. Stock (Page 6 line 2 (D))		<u>0.00%</u>	<u>0.00%</u>		
17	Weighted Return on Equity		4.15%	4.29%		
18	% of Equity to Capital Structure (Page 6, line 3 (B))		<u>53.59%</u>	<u>53.59%</u>		
19	Return on Equity (Page 6, line 3 (C))		<u>7.74%</u>	<u>8.02%</u>		

Otter Tail Power Company  
2022 North Dakota Annual Report

Average Weighted Cost of Capital - With All Riders, Normalized

		(A)	(B)	(C)	(D)
Line No.	Description	2022 Total	Ratio	Cost	Weighted Cost
1	Long Term Debt	752,990,671	46.41%	4.35%	2.02%
2	Preferred Equity	0	0.00%	0.00%	0.00%
3	Common Equity	869,346,098	53.59%	8.01%	4.29%
4	Total	1,622,336,769	100.00%		6.31%

Otter Tail Power Company  
2022 North Dakota Annual Report

## Miscellaneous

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
Line No.	Total Description	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013
	Customer Related (ND):										
	<b>Year End # of Customers (1)</b>										
1	Residential	45,535	45,584	45,614	45,620	45,862	45,882	45,743	45,689	45,379	45,191
2	Commercial	12,448	12,481	12,430	12,395	11,465	11,439	11,385	11,333	11,286	11,270
3	Industrial	285	283	278	277	980	979	978	984	947	950
4	Other	885	888	890	889	497	499	503	509	504	504
5	<b>Total Customers</b>	<b>59,153</b>	<b>59,236</b>	<b>59,212</b>	<b>59,181</b>	<b>58,804</b>	<b>58,799</b>	<b>58,609</b>	<b>58,515</b>	<b>58,116</b>	<b>57,915</b>
	<b>KWH's Sold</b>										
6	Residential	628,366,462	582,626,650	602,784,894	629,175,343	630,555,383	591,880,809	580,345,390	609,253,548	669,563,374	652,328,505
7	Commercial	518,102,686	470,598,314	511,173,319	517,757,884	309,037,831	300,470,972	291,700,647	296,940,142	339,108,033	319,824,033
8	Industrial	1,122,524,727	607,703,011	596,367,789	653,782,339	861,510,082	854,040,398	856,544,193	852,769,327	899,948,129	867,335,225
9	Other	27,194,689	26,994,553	29,522,372	29,278,133	29,467,197	29,625,196	29,262,956	29,829,127	30,127,525	29,593,473
10	Subtotal	2,296,188,564	1,687,922,528	1,739,848,374	1,829,993,699	1,830,570,493	1,776,017,375	1,757,853,186	1,788,792,144	1,938,747,061	1,869,081,236
11	Unbilled sales	21,527,683	4,732,945	(1,967,352)	(9,672,097)	3,250,372	11,845,290	5,681,679	(9,116,877)	(5,251,688)	17,390,019
12	<b>Total kWh</b>	<b>2,317,716,247</b>	<b>1,692,655,473</b>	<b>1,737,881,022</b>	<b>1,820,321,602</b>	<b>1,833,820,865</b>	<b>1,787,862,665</b>	<b>1,763,534,865</b>	<b>1,779,675,267</b>	<b>1,933,495,373</b>	<b>1,886,471,255</b>
	<b>System Wide Reliability Indices</b>										
13	SAIDI (total minutes)	118.6	79.0	91.3	128.2	85.3	86.5	110.5	100.6	74.2	99.7
14	SAIFI (frequency)	1.6	1.2	1.3	1.5	1.3	1.4	1.7	1.7	1.2	1.3
15	CAIDI (duration)	73.2	66.89	69.1	88.7	64.9	61.5	65.7	58.4	59.9	78.6

(1) Otter Tail implemented its new customer information system in February 2019. During this conversion, total customer counts by class were updated resulting in the change from 2018 to 2019.

**BEFORE THE  
NORTH DAKOTA PUBLIC SERVICE  
COMMISSION**

**Case No. PU-23-**

**Otter Tail Power Company's  
Report on Status of Smart Metering  
and Smart Grid Technologies**

**June 27, 2023**

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## Otter Tail Power Company 2021 Annual Report to North Dakota

### Report on Status of Smart Metering

In its Order dated August 8, 2007, Case No. PU-06-290, the North Dakota Public Service Commission, at ordering paragraph no. 2, required that:

**"Each jurisdictional electric utility shall include in its annual reports to the Commission, beginning with reports filed for 2007, a discussion of progress towards the feasibility of making smart metering available for all customers."**

References to smart grid and smart metering have been used interchangeably as the utility industry moves to adopt changes that make sense for each of the utilities' service areas. We've used technology to improve employee productivity and customer service for many years. Smart grid investments occur in many aspects of our work and our mission, which is:

*To produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the area in which we do business.*

The following lists some of the smart grid-type applications that we discussed in past filings and are still in place today. However, this filing does not go into detail for each of these areas:

- Peak-shaving technologies
- Energy storage systems
- Time-varying rates
- Electricity metering
- Power Profiler
- Bill Analyzer
- Interruption Monitoring System

This update focuses on updates to our:

- Customer Information System
- Customer Experience Platform
- Advanced Metering Infrastructure
- Demand Response
- Outage Management System

In addition, we provide high-level information related to technologies that encompass smart metering in our Innovation 2030 (I2030) initiative.

## **Customer Information System (CIS)**

Otter Tail Power Company's utilizes Cayenta Utilities (CU) as its customer information system. The first major upgrade was completed in January 2022. Major upgrades are done approximately every 3 years. Between major upgrades, the system is updated on a quarterly basis to keep the system current. Critical patches are applied to the system as they become available. The 2022 upgrade will ensure we are on the latest version of Cayenta's software as integration with other systems begins as part of our I2030 project list. The integration between CU and the Customer Experience Platform, Outage Management System, and Advanced Metering Infrastructure with Meter Data Management projects will be critical for both internal functions and processes as well as Customer Experience efforts. We continue to build new configurations and enhancements into the CU system to enhance internal processes and to meet the growing needs of real-time customer communications and information. We continue to utilize Cayenta Utilities mobile work management (MWM) tool for our short cycle service orders. Our field representatives receive all of their short cycle orders through an MWM app on their smart phone or other mobile device.

## **Customer Experience Platform (CEP)**

Otter Tail Power continues to remain focused on providing the best possible experience for our customers. As part of this effort, we have contracted with Accelerated Innovations to develop an online platform that will provide customers enhanced functionality in the areas of bill payment, usage information, and outage communications. A preference center will allow customers to choose the communications they want to receive and the method by which they would like to receive them. A mobile application will allow customers to access account information on the go. This platform is intended to integrate fully with our Outage Management System, Customer Information System, Paymentus payment provider portal, as well as MDM/AMI and will provide the most comprehensive information to the customer when these other systems are in place.

Implementation began in April 2022 and is projected to go live in Q3 2023. This platform continues to be evaluated for further improvements to enhance the customer experience.

## **Advanced Metering Infrastructure (AMI)**

Otter Tail Power continues to move forward with our AMI project as part of our Smart Grid initiative. In August 2020, we presented information regarding our AMI project to the ND PSC during a Periodic Information Exchange (PIE). In February 2021, the Company filed an Advanced Determination of Prudence (ADP) with the ND PSC for the AMI project. In this filing we indicated the AMI communication infrastructure will support many other systems, and we specifically expect the AMI system to support our new load management system. In September 2021, the ND PSC approved the ADP with the requirement for the method of recovery to be determined at a later date.

Otter Tail completed the development phase of the project in 2021 and selected Landis and Gyr as the provider of the AMI and Meter Data Management (MDM) systems. Otter Tail contracted with Allegiant for meter installation. We are currently working through integration and planning for meter deployment. Our ongoing cost forecast continues to support the cost information we provided in our ADP filing.

Otter Tail anticipates initial deployment of the first 1,000 meters for pilot/testing purposes in the Fall of 2023. Otter Tail expects to complete installation by the end of 2024; however, persistent supply chain delays may push this timeline to early 2025.

### **Demand Response (DR)**

Otter Tail has taken several actions to move the project forward over the past several months. The Request for Proposals for the DR replacement system was released, and six responses were received in November 2022. Otter Tail reviewed the responses in conjunction with its consultant Katama Technologies. Vendor demonstrations were held February 22<sup>nd</sup> through February 24<sup>th</sup>. Follow-up questions were posed to and answered by vendors in separate meetings. Best and Final Offers have been received for the remaining vendors of interest. Otter Tail expects to select a vendor(s) in June 2023, allowing the Company to meet the proposed project schedule. Informational presentations are scheduled to be given to the company and corporate boards in September.

Otter Tail was also invited to submit a full application for grant opportunities related to the 2021 Infrastructure Investment and Jobs Act. An award through this act would reduce overall project costs. An application was submitted by the deadline and Otter Tail awaits the final decision.

### **Outage Management System (OMS)**

In 2021, Otter Tail issued an RFP for an OMS system and selected Milsoft to provide the solution. In late 2021 and early 2022, Otter Tail Power completed the contract negotiation with Milsoft. The system went live in December 2022 and is will continue to add functionality as AMI is deployed.

### **Innovation 2030 Initiative (I2030)**

As part of our Smart Grid initiatives, our I2030 Portfolio includes projects that support our objectives of increased customer engagement, increased safety and reliability, and increased business efficiency through technology and process opportunities. Each of the prior discussed projects are part of the larger I2030 program. I2030, a company initiative that began in 2016, continues in the planning, development, and execution stages of several technologies. In addition to the prior projects discussed, the Company has completed the deployment of a new Staking system, Enterprise Service Bus, and Financial Information System.. Another area under consideration as part of I2030 is a Work Management System. We continue to review our evaluation and business case justifications for all projects within the portfolio.



# ANNUAL REPORT 2022





## ELECTRIC PLATFORM



**Otter Tail Power Company**  
 Electric utility  
 Headquarters: Fergus Falls, MN  
 Founded 1907  
 President, Tim Rogelstad  
 728 full-time employees  
[www.otpco.com](http://www.otpco.com)



## MANUFACTURING PLATFORM



**BTD Manufacturing, Inc.**  
 Metal fabricator  
 Headquarters: Detroit Lakes, MN  
 Acquired 1995  
 President, Paul Gintner  
 1,281 full-time employees  
[www.btdmfg.com](http://www.btdmfg.com)



**T.O. Plastics, Inc.**  
 Custom plastic parts manufacturer  
 Headquarters: Clearwater, MN  
 Acquired 2001  
 President, Paul Meschke  
 204 full-time employees  
[www.toplastics.com](http://www.toplastics.com)



**Northern Pipe Products, Inc.**  
 PVC pipe manufacturer  
 Headquarters: Fargo, ND  
 Acquired 1995  
 President, Terry Mitzel  
 95 full-time employees  
[www.northernpipe.com](http://www.northernpipe.com)



**Vinyltech Corporation**  
 PVC pipe manufacturer  
 Headquarters: Phoenix, AZ  
 Acquired 2000  
 President, Terry Mitzel  
 78 full-time employees  
[www.vtpipe.com](http://www.vtpipe.com)



# VISION

We build top-performing companies in a diversified organization with an electric utility as our foundation.



# MISSION

We deliver value by building strong electric utility and manufacturing platforms.

**FOR OUR SHAREHOLDERS** we deliver above-average returns through commercial and operational excellence and growing our businesses.

**FOR OUR CUSTOMERS** we commit to quality and value in everything we do.

**FOR OUR EMPLOYEES** we provide an environment of opportunity with accountability where all people are valued and empowered to do their best work.



# VALUES

## INTEGRITY

We conduct business responsibly and honestly.

## SAFETY

We provide safe workplaces and require safe work practices.

## PEOPLE

We build respectful relationships and create inclusive environments where all people can thrive.

## PERFORMANCE

We strive for excellence, act on opportunity, and deliver on commitments.

## COMMUNITY

We improve the communities where we work and live.

# OBJECTIVES

**GROW** our businesses

**ACHIEVE** operational and commercial excellence

**ACHIEVE** talent excellence

	2022	2021	PERCENT CHANGE
<b>CONSOLIDATED OPERATIONS</b> (\$ in thousands, except per share amounts)			
Operating Revenues	\$ 1,460,209	\$ 1,196,844	22.0
Net Income	\$ 284,184	\$ 176,769	60.8
Diluted Earnings per Share	\$ 6.78	\$ 4.23	60.3
Dividends per Common Share	\$ 1.65	\$ 1.56	5.8
Return on Average Common Equity	25.6%	19.2%	33.3
Book Value per Common Share	\$ 29.24	\$ 23.84	22.6
Cash Flow from Operating Activities	\$ 389,309	\$ 231,243	68.4
Number of Common Shares Outstanding	41,631,113	41,551,524	0.2
Number of Common Shareholders	11,748	12,038	(2.4)
Closing Stock Price	\$ 58.71	\$ 71.42	(17.8)
Total Return (share price appreciation plus dividends)	(15.5)%	71.3%	n/m
Total Market Value of Common Stock	\$ 2,444,163	\$ 2,967,610	(17.6)
<b>ELECTRIC PLATFORM</b> (\$ in thousands)			
Operating Revenues	\$ 549,699	\$ 480,321	14.4
Total Retail Electric Sales (MWH)	5,592,368	4,789,879	16.8
Operating Income	\$ 113,138	\$ 106,964	5.8
Customers	133,414	133,304	0.1
Gross Plant Investment	\$ 2,958,311	\$ 2,833,371	4.4
Total Assets	\$ 2,351,961	\$ 2,283,776	3.0
Capital Expenditures	\$ 147,869	\$ 140,031	5.6
<b>MANUFACTURING PLATFORM</b> (\$ in thousands)			
Operating Revenues	\$ 910,510	\$ 716,523	27.1
Operating Income	\$ 293,643	\$ 156,874	87.2
Total Assets	\$ 372,187	\$ 413,609	(10.0)
Capital Expenditures	\$ 23,199	\$ 31,730	(26.9)

OPERATING REVENUES  
**↑ 22%**  
NET INCOME  
**↑ 61%**  
IN 2022

OPERATING REVENUES  
**↑ 14%**  
NET INCOME  
**↑ 10%**  
IN 2022

OPERATING REVENUES  
**↑ 27%**  
NET INCOME  
**↑ 88%**  
IN 2022





## TO OUR SHAREHOLDERS



CHARLES S. MACFARLANE  
PRESIDENT AND CEO

### A REMARKABLE YEAR

Otter Tail Corporation and its companies experienced unique successes this year. We are delivering value for our employees, customers, and shareholders as we continue building top-performing companies.

Through our combined efforts in 2022, we achieved record financial results. Our diversified business model produced consolidated net income and diluted earnings per share of \$284.2 million and \$6.78 respectively, compared with \$176.8 million and \$4.23 in 2021; earnings per share increased 60.3 percent year over year. Our return on equity in 2022 was 25.6 percent.

We have paid dividends on our common stock for 84 years, or 337 consecutive quarters. The dividend yield at December 31, 2022, was 2.8 percent. Our total shareholder return over the five-year period ending December 31, 2022, was 53.0 percent. Our annual indicated dividend per share for 2023 is \$1.75, a 6.1 percent increase over our 2022 dividend rate.

At the Edison Electric Institute (EEI) Financial Conference in November 2022, Otter Tail Corporation received the EEI Index Award for the top performing small-capitalization utility for the second year in a row, with a total shareholder return of 64 percent over the five-year period ending September 30, 2022. This award is presented annually to EEI member companies that have achieved the highest total shareholder return in the large-, mid-, and small-capitalization categories.

Our 2022 financial results are highlighted throughout this Annual Report. While financial results alone do not provide the full picture of a corporation's health, they do help demonstrate our commitment to delivering value for our shareholders, our emphasis on consistently meeting customer expectations, and our efforts to ensure every employee can thrive and is positioned for success.

### UTILITY EXECUTES ON CAPITAL INVESTMENT PLAN

Otter Tail Power Company again executed on its capital investment plan and benefited from an increase in sales volumes in 2022 to produce earnings of \$80.0 million, a 10.4 percent increase from last year. The addition of new customers, high availability at our coal plants, transmission investments, and a successful rate case, as well as excellent recovery efforts following significant storms, contributed to a strong finish to our year. All of this was made possible through noteworthy day-to-day operational excellence. We grew average rate base by 3.1 percent in 2022, primarily through capital investments in energy generation and regional transmission projects.

We continue to work toward a cleaner energy future. Our target is to reduce carbon emissions from our owned generation resources approximately 50 percent from 2005 levels by 2025 and 97 percent by 2050—while keeping residential rates among the lowest in the nation. Additionally, our goal is for our owned and contracted energy generation to be more than 50 percent renewable by 2025.

We began construction on Hoot Lake Solar, a \$60 million, 49-megawatt (MW) solar farm, in May. With proximity to an existing transmission interconnection from our retired coal-fired Hoot Lake Plant, the project allows us to add renewable energy to the grid without investing in additional, costly infrastructure. We began generating electricity at Hoot Lake Solar in early 2023 and expect to be fully operational by midyear, with 100 percent of the costs and benefits allocated to Minnesota customers.

In November the Minnesota Public Utilities Commission granted our request to amend our Integrated Resource Plan (IRP) procedural schedule. Otter Tail Power filed its IRP in September 2021. In our original plan, we requested authority to add on-site fuel storage at Astoria Station in South Dakota, to add

150 MW of solar generation at a location yet to be determined, and to commence the process to withdraw from our 35 percent ownership interest in Coyote Station in North Dakota by December 31, 2028. Since that filing, we have seen significant changes in the energy industry, including the Midcontinent Independent System Operator's (MISO) new seasonal resource adequacy construct and significant increase in winter and spring planning reserve margins, along with the enactment of the Inflation Reduction Act—which together drive the need to update our IRP. We plan to file an updated plan in March 2023 given these new circumstances. We will maintain the original procedural schedule as it relates to adding on-site fuel storage at Astoria Station, which is pictured on the cover of this report.

In July the MISO Board of Directors approved \$10.3 billion in transmission projects focused on its Midwest Subregion. These projects are the first group of four in MISO's Long-Range Transmission Planning process that aims to integrate new generation resources—as outlined in MISO member and state plans—and increase resilience in the face of severe weather events. Two transmission projects, the Jamestown-Ellendale project and the Big Stone South-Alexandria project are in our service area, and Otter Tail Power will be a joint owner in each project. We estimate our total capital investment in these projects to be \$390 million.

We also continued plans for installing Advanced Metering Infrastructure (AMI). We will start with a pilot program in 2023 and plan to finish full deployment in 2024, upgrading more than 174,000 electric meters with meters that enable two-way communication with our systems. AMI lays the groundwork for improved outage response and communication and provides the ability to remotely find the location of an outage, read meters, and turn meters on and off. When combined with systems we have in place today, including an Outage Management System and telephone-based Integrated Voice Response, customers will have more visibility into their energy use and account information as we more efficiently and effectively meet their electric service needs.

In January 2023 we purchased the Ashtabula III wind farm, located in eastern North Dakota. We have purchased wind-generated electricity from Ashtabula III since 2013 through a power purchase agreement, but owning the facility provides a lower cost alternative than maintaining the purchased power arrangement. The purchase added 62.4 MW of nameplate capacity to our owned generation assets.

Thanks to resilient and hard-working employees, Otter Tail Power continues its long tradition of operational excellence while providing customers with a safe, reliable, and low-cost essential service. This was highlighted in January 2023, when EEI announced at its board meeting that Otter Tail Power was selected as one of 18 recipients of EEI's Emergency Recovery Award for our outstanding restoration efforts during and after the storm that hit parts of our service area on May 12, 2022. EEI's Emergency Recovery Award recognizes member companies that put forth outstanding efforts to restore service promptly to the public following a storm or natural disaster.

We will continue to make system investments to meet customers' expectations, manage operating and maintenance

costs, transition to a cleaner energy future, and improve reliability and safety.

## MANUFACTURING PLATFORM DELIVERS OUTSTANDING FINANCIAL RESULTS

Northern Pipe Products and Vinyltech, our PVC pipe manufacturing companies that comprise our Plastics Segment, delivered extraordinary financial results in 2022, producing record earnings of \$195.4 million. Our employees effectively capitalized on unique industry supply and demand conditions while navigating volatile input costs, supply challenges, and unpredictable customer demand. We currently expect these industry conditions to normalize throughout 2023.

We have commenced work on a facility expansion and site improvement plan at our Vinyltech facility in Phoenix, Arizona. The project will provide an organic growth opportunity for our business, adding increased raw material storage and handling capabilities and additional manufacturing capacity at this location. We currently anticipate the project will be complete by the end of 2024.

BTD, our contract metal fabricator, produced earnings of \$16.6 million in 2022, a 13.0 percent increase from 2021. Strong customer demand across most end markets drove the increase in earnings and more than offset a decline in scrap metal revenues as steel prices receded from recent highs. Our BTD employees were challenged by, and effectively navigated, volatile steel markets, unpredictable customer demand, workforce challenges, and persistent inflationary pressures while maintaining excellent quality and on-time delivery.

T.O. Plastics, our plastics thermoforming manufacturer, benefited from robust customer demand for horticulture products to produce earnings growth of 74 percent compared to last year. Improved price realization, which more than offset inflationary cost pressures, also contributed to earnings growth in 2022.

Both BTD and T.O. Plastics continue to do an excellent job managing through the current inflationary environment and supply chain disruptions while meeting strong customer demand.

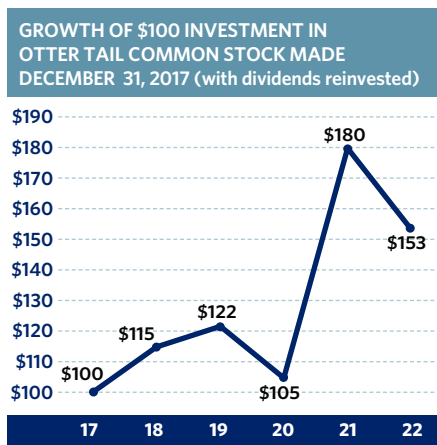
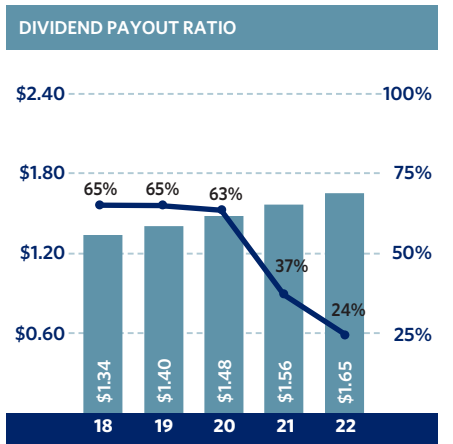
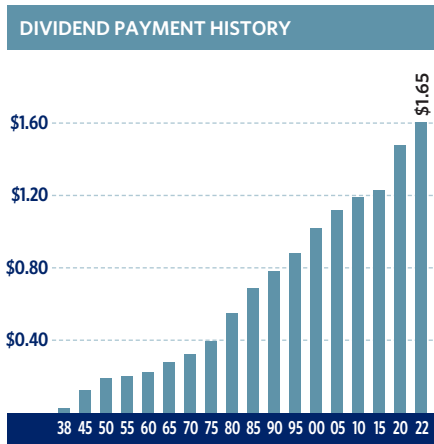
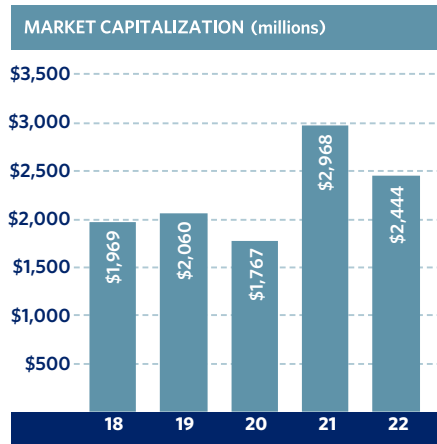
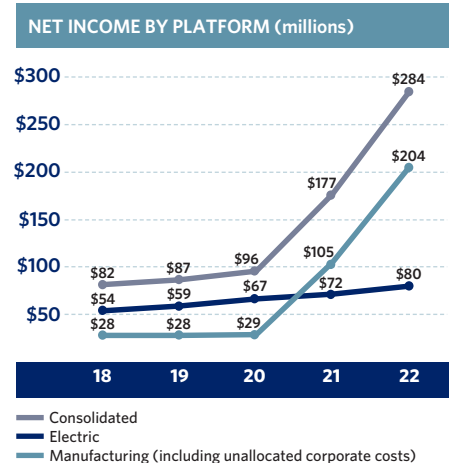
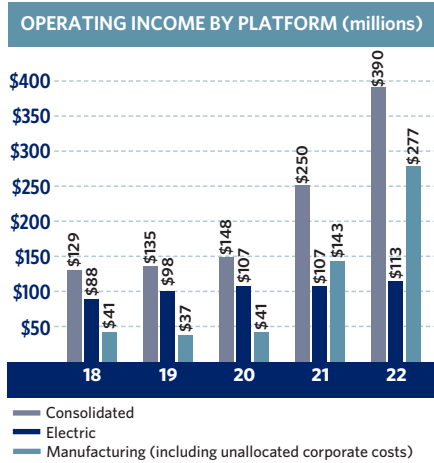
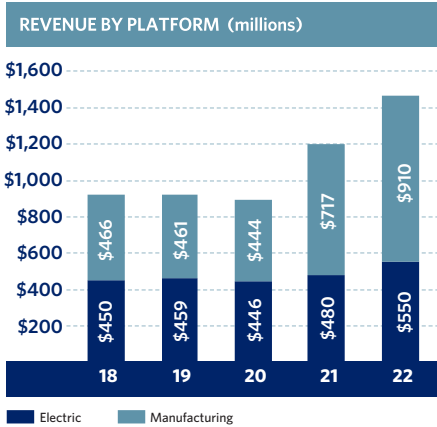
## FOCUSED ON OUR SHARED SUCCESS

We are in unique times and our employees are responding in extraordinary ways. Our vision, mission, and values—which we refreshed in 2022—guide us toward fulfilling our strategic objectives to grow our businesses and achieve operational, commercial, and talent excellence.

We have a strong and steady future. Thank you to our employees for everything you do to ensure our top performance. And thank you to our customers and shareholders for your confidence in our ongoing success.



Charles S. MacFarlane  
President and Chief Executive Officer



Total shareholder return has grown at a compounded annual rate of 53.0 percent over the past five years, and we have paid dividends on common stock for 84 years, or 337 consecutive quarters.

SELECTED COMMON SHARE DATA	2022	2021	2020	2019	2018	2017
Market Price:						
High	\$ 82.46	\$ 71.71	\$ 56.90	\$ 57.74	\$ 51.88	\$ 48.65
Low	\$ 52.60	\$ 39.35	\$ 30.95	\$ 45.94	\$ 39.00	\$ 35.65
Common Price/Earnings Ratio:						
High	12.2	17.0	24.3	26.6	25.2	26.7
Low	7.8	9.3	13.2	21.2	18.9	19.6
Book Value Per Common Share	\$ 29.24	\$ 23.84	\$ 21.00	\$ 19.46	\$ 18.38	\$ 17.62

SELECTED DATA AND RATIOS	2022	2021	2020	2019	2018	2017
Interest Coverage Before Taxes	10.8x	6.5x	4.1x	4.1x	4.0x	4.3x
Effective Income Tax Rate (percent)	21	17	17	17	15	27
Return on Capitalization Including Short-Term Debt (percent)	15.6	11.6	7.6	8.0	8.4	7.9
Return on Average Common Equity (percent) <sup>1</sup>	25.6	19.2	11.6	11.6	11.5	10.6
Dividend Payout Ratio (percent)	24	37	63	65	65	70
Cash Realization <sup>2</sup>	1.37	1.31	2.21	2.13	1.74	2.40
Capital Ratio (percent):						
Short Term and Long-Term Debt	40.6	46.3	49.3	47.1	45.5	46.4
Common Equity	59.4	53.7	50.7	52.9	54.5	53.6
	100.0	100.0	100.0	100.0	100.0	100.0

(1) Earnings available for common shares divided by the 13-month average of month-end common equity balances.

(2) Net cash provided by operating activities divided by net income.

SELECTED ELECTRIC OPERATING DATA	2022	2021	2020	2019	2018	2017
Revenues (thousands)						
Residential	\$ 143,888	\$ 135,361	\$ 127,260	\$ 131,988	\$ 125,045	\$ 116,990
Commercial and Industrial	318,494	262,408	254,951	267,125	256,331	251,092
Other Retail	7,918	7,715	7,311	7,365	6,875	6,849
Total Retail	470,300	405,484	389,522	406,478	388,251	374,931
Sales for Resale	18,539	17,936	4,857	5,007	7,735	5,173
Other Electric	60,860	56,901	51,751	47,612	54,269	54,433
Total Electric	\$ 549,699	\$ 480,321	\$ 446,130	\$ 459,097	\$ 450,255	\$ 434,537
Kilowatt-hours Sold (thousands)						
Residential	1,309,249	1,241,951	1,266,232	1,303,317	1,321,132	1,243,194
Commercial and Industrial	4,224,190	3,489,342	3,446,743	3,598,002	3,590,651	3,506,707
Other	58,928	58,586	63,712	67,770	65,177	65,083
Total Retail	5,592,368	4,789,879	4,776,687	4,969,089	4,976,960	4,814,984
Sales for Resale	267,184	420,044	236,528	198,569	271,840	203,397
Total	5,859,552	5,209,923	5,013,215	5,167,658	5,248,800	5,018,381
Annual Retail Kilowatt-hour Sales Growth (percent)	16.8	0.3	(3.9)	(0.2)	3.4	1.4
Heating Degree Days <sup>3</sup>	7,122	5,794	6,174	7,240	6,904	5,931
Cooling Degree Days <sup>4</sup>	531	704	534	392	567	380
Average Revenue Per Kilowatt-hour						
Residential	10.99¢	10.90¢	10.05¢	10.13¢	9.46¢	9.41¢
Commercial and Industrial	7.54¢	7.52¢	7.40¢	7.42¢	7.14¢	7.16¢
All Retail	8.41¢	8.47¢	8.15¢	8.18¢	7.80¢	7.79¢
Customers						
Residential	103,950	103,835	103,658	103,328	104,242	104,038
Commercial and Industrial	27,578	27,582	27,468	27,348	27,223	27,123
Other	1,886	1,887	1,906	1,911	993	995
Total Electric Customers	133,414	133,304	133,032	132,587	132,458	132,156
Residential Sales						
Average Kilowatt-hours Per Customer <sup>5</sup>	12,556	11,812	12,186	12,689	12,740	11,962
Average Revenue Per Residential Customer	\$ 1,412	\$ 1,294	\$ 1,250	\$ 1,289	\$ 1,226	\$ 1,161
Depreciation Reserve (thousands)						
Electric Plant in Service	\$ 2,844,379	\$ 2,758,445	\$ 2,531,312	\$ 2,212,884	\$ 2,019,721	\$ 1,981,018
Depreciation Reserve	\$ 859,988	\$ 817,302	\$ 778,988	\$ 731,110	\$ 699,642	\$ 662,431
Reserve to Electric Plant (percent)	30.2	29.6	30.8	33.0	34.6	33.4
Composite Depreciation Rate (percent)	2.40	2.67	2.63	2.81	2.76	2.74
Peak Demand and Net Generating Capability						
Peak Demand (kilowatts)	987,628	865,120	844,929	923,962	911,726	916,522
Net Generating Capability (kilowatts): <sup>6</sup>						
Steam	406,200	406,800	548,100	548,700	548,500	547,600
Wind	288,000	288,000	288,000	138,000	138,000	138,000
Combustion Turbines	343,700	352,500	107,900	105,100	106,200	109,900
Hydro	2,500	2,600	2,500	2,800	2,900	2,800
Total Owned Generating Capability	1,040,400	1,049,900	946,500	794,600	795,600	798,300

Notes:

(3) Based on 55 degrees Fahrenheit base and average method.

(4) Based on 65 degrees Fahrenheit base and average method.

(5) Based on average number of customers during the year.

(6) Measurement of net dependable capacity.

# EXECUTIVE LEADERSHIP

## **CHARLES S. MACFARLANE**

President and  
Chief Executive Officer

## **KEVIN G. MOUG**

Senior Vice President and  
Chief Financial Officer

## **TIMOTHY J. ROGELSTAD**

Senior Vice President,  
Electric Platform;  
President, Otter Tail  
Power Company

## **JOHN S. ABBOTT**

Senior Vice President,  
Manufacturing Platform;  
President, Varistar

## **PAUL L. KNUTSON**

Vice President,  
Human Resources

## **JENNIFER O. SMESTAD**

Vice President,  
General Counsel,  
and Corporate Secretary

## **STEPHANIE A. HOFF**

Director,  
Corporate Communications

# DIRECTORS

## **NATHAN I. PARTAIN**

Chairman of the Board  
League City, Texas  
Retired President and  
Chief Investment Officer,  
Duff & Phelps Investment  
Management Co.

## **CHARLES S. MACFARLANE**

Fergus Falls, Minnesota  
President and Chief  
Executive Officer,  
Otter Tail Corporation;  
Chief Executive Officer,  
Otter Tail Power Company

## **KAREN M. BOHN**

A/CG  
Edina, Minnesota  
President, Galeo Group, LLC  
(management consulting firm)

## **JEANNE H. CRAIN**

A/C  
Minneapolis, Minnesota  
President and Chief Executive Officer,  
Bremer Financial Corporation

## **JOHN D. ERICKSON**

Fergus Falls, Minnesota  
Advisor to ECJV Holding, LLC;  
Former President and  
Chief Executive Officer,  
Otter Tail Corporation  
(utility and diversified businesses)

## **STEVEN L. FRITZE**

A/CG  
Eagan, Minnesota  
Retired Chief Financial  
Officer, Ecolab Inc.  
(diversified manufacturing)

## **DR. KATHRYN O. JOHNSON**

C/CG  
Hill City, South Dakota  
Owner and Principal, Johnson  
Environmental Concepts  
(geochemical consulting firm)

## **DR. MICHAEL E. LEBEAU**

C/CG  
Bismarck, North Dakota  
System Vice President and  
Chief Administrative Officer  
Health Services Division  
Sanford Health

## **MARY E. LUDFORD**

A/CG  
Chicago, Illinois  
Retired Chief Audit Executive and  
Deputy Chief Security Officer,  
Exelon Corporation  
(regulated transmission and  
distribution utilities)

## **JAMES B. STAKE**

A/C  
Edina, Minnesota  
Retired Executive Vice President,  
Enterprise Services, 3M Company  
(diversified manufacturing)

## **THOMAS J. WEBB**

A/C  
Richland, Michigan  
Advisor, Retired Vice President  
and Chief Financial Officer,  
CMS Energy Corporation  
(gas and electric utility)

### *Committees:*

*A—Audit*

*C—Compensation and Human  
Capital Management*

*CG—Corporate Governance*



UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549

**FORM 10-K**

(Mark One)

**Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2022 or

**Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission File Number **0-53713**

**OTTER TAIL CORPORATION**

(Exact name of registrant as specified in its charter)

**Minnesota**

(State or other jurisdiction of incorporation or organization)

**27-0383995**

(I.R.S. Employer Identification No.)

**215 South Cascade Street, Box 496, Fergus Falls, Minnesota**

(Address of principal executive offices)

**56538-0496**

(Zip Code)

Registrant's telephone number, including area code: **866-410-8780**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares, par value \$5.00 per share	OTTR	The Nasdaq Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes  No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes  No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes  No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer

Accelerated Filer

Non-Accelerated Filer

Smaller Reporting Company

Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes  No

As of June 30, 2022, the aggregate market value of common stock held by non-affiliates was **\$2,689,579,964**.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **41,631,763 Common Shares (\$5 par value) as of January 31, 2023**.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive Proxy Statement for its 2023 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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## DEFINITIONS

The following abbreviations or acronyms are used in the text.

ACE	Affordable Clean Energy	LIBOR	London Interbank Offered Rate
AFUDC	Allowance for Funds Used During Construction	LSA	Lignite Sales Agreement
AMDT	Advanced Meter and Distribution Technology	Merricourt	Merricourt Wind Energy Center
ARO	Asset Retirement Obligation	MISO	Midcontinent Independent System Operator
ARP	Alternative Revenue Program	MPUC	Minnesota Public Utilities Commission
Astoria	Astoria Station	NAV	Net Asset Value
BTD	BTD Manufacturing, Inc.	NDDEQ	North Dakota Department of Environmental Quality
CCMC	Coyote Creek Mining Company, L.L.C.	NDPSC	North Dakota Public Service Commission
CDD	Cooling Degree Day	NERC	North American Electric Reliability Corporation
CIP	Conservation Improvement Program	Northern Pipe	Northern Pipe Products, Inc.
CO <sub>2</sub>	Carbon dioxide	OTC	Otter Tail Corporation
COSO	Committee of Sponsoring Organizations of the Treadway Commission	OTP	Otter Tail Power Company
EEl	Edison Electric Institute	Paris Agreement	United Nations Framework Convention on Climate Change
EPA	Environmental Protection Agency	PFAS	Polyfluoroalkyl substances
ERISA	Employee Retirement Income Security Act of 1974	PIR	Phase-in Rider
ESSRP	Executive Survivor and Supplemental Retirement Plan	PSLRA	Private Securities Litigation Reform Act of 1995
FCA	Fuel Clause Adjustment	PTCs	Production tax credits
FERC	Federal Energy Regulatory Commission	PVC	Polyvinyl chloride
GCR	Generation Cost Recovery Rider	RHR	Regional Haze Rule
GHG	Greenhouse Gas	ROE	Return on equity
HDD	Heating Degree Day	RRR	Renewable Resource Rider
ISO	Independent System Operator	SDPUC	South Dakota Public Utilities Commission
IRA	Inflation Reduction Act	SEC	Securities and Exchange Commission
IRP	Integrated Resource Plan	SIP	State implementation plans
ITCs	Investment Tax Credits	SOFR	Secured Overnight Financing Rate
kV	kiloVolt	T.O. Plastics	T.O. Plastics, Inc.
kW	kiloWatt	TCR	Transmission Cost Recovery Rider
kwh	kilowatt-hour	Vinyltech	Vinyltech Corporation

## WHERE TO FIND MORE INFORMATION

We make available free of charge at our website ([www.ottertail.com](http://www.ottertail.com)) our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy and information statements, Forms 3, 4 and 5 filed on behalf of directors and executive officers and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). These reports are also available on the SEC's website ([www.sec.gov](http://www.sec.gov)). Information on our and the SEC's websites is not deemed to be incorporated by reference into this report on Form 10-K.

## FORWARD-LOOKING INFORMATION

This report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the PSLRA). When used in this Form 10-K and in future filings by the Company with the SEC, in the Company's press releases and in oral statements, words such as "anticipate," "believe," "could," "estimate," "expect," "future," "goal," "intend," "likely," "may," "outlook," "plan," "possible," "potential," "predict," "probable," "projected," "should," "target," "will," "would" or similar expressions are intended to identify forward-looking statements within the meaning of the PSLRA. Such statements are based on current expectations and assumptions and entail various risks and uncertainties that could cause actual results to differ materially from those expressed in such forward-looking statements. Such risks and uncertainties include the various factors set forth in Item 1A. Risk Factors of this report on Form 10-K and in our other SEC filings.

# PART I

## ITEM 1. BUSINESS

Otter Tail Corporation (OTC) has interests in diversified operations that include an electric utility and manufacturing and plastic pipe businesses with corporate offices located in Fergus Falls, Minnesota and Fargo, North Dakota.

We classify our five operating companies into three reportable segments consistent with our business strategy and management structure. The following table depicts our three segments and the subsidiary entities included within each segment:

ELECTRIC SEGMENT	MANUFACTURING SEGMENT	PLASTICS SEGMENT
Otter Tail Power Company (OTP)	BTD Manufacturing, Inc. (BTD)	Northern Pipe Products, Inc. (Northern Pipe)
	T.O. Plastics, Inc. (T.O. Plastics)	Vinyltech Corporation (Vinyltech)

**Electric** includes the generation, purchase, transmission, distribution and sale of electric energy in western Minnesota, eastern North Dakota and northeastern South Dakota. OTP, our largest operating subsidiary and primary business since 1907, serves more than 133,000 customers in more than 400 communities across a predominantly rural and agricultural service territory.

**Manufacturing** consists of businesses in the following manufacturing activities: contract machining; metal parts stamping; fabrication and painting; and production of plastic thermoformed horticultural containers, life science and industrial packaging, material handling components and extruded raw material stock. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

**Plastics** consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the western half of the United States and Canada.

Throughout the remainder of this report, we use the terms "Company", "us", "our", or "we" to refer to OTC and its subsidiaries collectively. We will also refer to our Electric, Manufacturing and Plastics segments and our individual subsidiaries as indicated above.

### INVESTMENT AND GROWTH STRATEGY

We maintain a moderate risk profile by investing in rate base growth opportunities in our Electric segment and organic growth opportunities in our Manufacturing and Plastics segments (collectively, our manufacturing platform). This strategy and risk profile are designed to provide a more predictable earnings stream, maintain our credit quality and preserve our ability to fund our dividend payments.

Our long-term focus remains on executing our strategy to grow our business and achieving operational, commercial and talent excellence to strengthen our position in the markets we serve. We remain confident in our ability to achieve a compounded annual growth rate in earnings per share in the range of five to seven percent using 2024 as the base year. We currently expect to see elevated earnings per share from our manufacturing platform into 2023 with our earnings mix expected to move to approximately 65% from our Electric segment and 35% from our manufacturing platform beginning in 2024. We expect our earnings growth beyond 2024 to be driven by rate base investments in our Electric segment and from existing capacities and planned investments within our Manufacturing and Plastics segments.

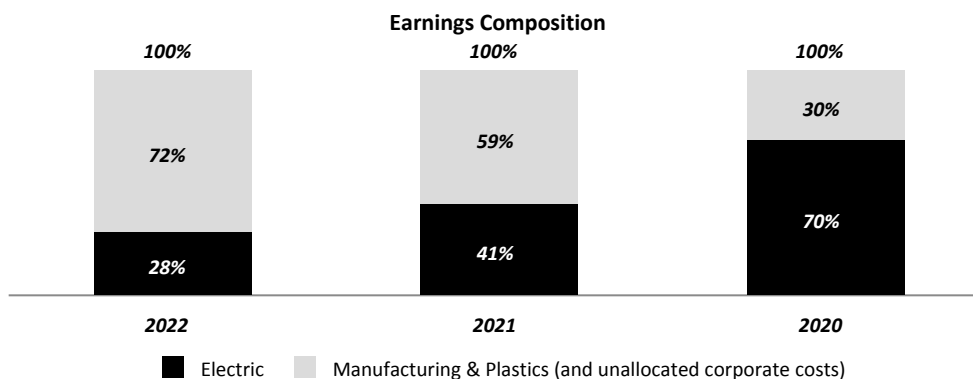
Over the past two years, we delivered earnings growth well in excess of our five to seven percent target due to unique industry conditions within the PVC pipe industry which led to extraordinary revenue, earnings and cash flow growth in our Plastics Segment.

We will continue to review our business portfolio to identify additional opportunities to improve our risk profile, enhance our credit metrics and generate additional sources of cash to support the organic growth opportunities in our Electric, Manufacturing, and Plastics segments. We will also evaluate opportunities to allocate capital to potential acquisitions. We are a committed long-term owner and do not acquire companies in pursuit of short-term gains. However, we will divest businesses which no longer fit into our strategy and risk profile over the long term.

We maintain a set of criteria used in evaluating the strategic fit of our operating businesses. The operating company should:

- Maintain a minimum level of net earnings and a return on invested capital in excess of the Company's weighted-average cost of capital,
- Have a strategic differentiation from competitors and a sustainable cost advantage,
- Operate within a stable and growing industry and be able to quickly adapt to changing economic cycles, and
- Have a strong management team committed to operational and commercial excellence.

Our actual mix of earnings for the years ended December 31, 2022, 2021, and 2020 was as follows:



## HUMAN CAPITAL

Our employees are a critical resource and an integral part of our success. We strive to provide an environment of opportunity and accountability where people are valued and empowered to do their best work. We are focused on the health and safety of our employees and creating a culture of inclusion, excellence and learning. Our human capital management efforts include monitoring various metrics and objectives associated with i) employee safety, ii) workforce stability, iii) management and workforce demographics, including gender, racial and ethnic diversity, iv) leadership development and succession planning and v) productivity. We have established the following programs in furtherance of these efforts:

**Safety** - Safety is one of our core values. In managing our business, we focus on the safety of our employees and have implemented safety programs and management practices to promote a culture of safety. Safety is also a metric used and evaluated in determining annual incentive compensation. We continually monitor the Occupational Safety and Health Administration (OSHA) Total Recordable Incident Rate (number of work-related injuries per 100 employees for a one-year period) and Lost Time Incident Rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). New cases are reported and evaluated for corrective action during monthly safety meetings attended by safety professionals at all locations. Our 2022 Total Recordable Incident Rate was 2.08, compared to 1.86 in 2021 and our Lost Time Incident Rate was 0.49, compared to 0.57 in 2021. In both 2022 and 2021 these rates were favorable when compared to the rates of our peers.

**Employee and Leadership Development, Succession Planning and Training Programs** - We invest in leadership development for various levels of employees, management and leaders throughout the Company to build enterprise-wide understanding of our culture, strategy and processes. Annual succession planning, individual development planning, mentoring, and supervisory and leadership development programs all play a role in ensuring a capable leadership team now and in the future. Our skill progression and technical training programs help to retain a stable and skilled workforce.

**Workforce Stability** - Recruiting, retaining and developing employees is an important factor in our continued success and growth. We regularly evaluate our recruiting programs, employee retention and turnover rates.

**Employee Engagement** - To enhance the effectiveness of our workforce and to help our companies continue to be places where our employees choose to work and thrive, we have undertaken a multi-year series of employee engagement surveys. We use the feedback to help shape the employee programs of our organization.

**Diversity, Equity, and Inclusion** - We expect, and are committed to, diversity, equity and inclusion as part of who we are, what we value and how we achieve individual, business and community success. We hold every employee accountable for their behavior in maintaining a workplace free of discrimination and harassment. We have implemented education initiatives for all employees, aimed at inclusive leadership and a respectful workplace, focused on identities and culture, unconscious bias, the power of diverse teams and culturally sensitive conversations. We have implemented initiatives to improve upon our demographic profile, including revised hiring processes and a commitment to diverse interview slates.

**Code of Business Ethics** - We require employees to complete training on several topics associated with our code of business ethics to reinforce our commitment to compliance with laws, regulations and values that guide who we are and how we do business.

As of December 31, 2022, we employed 2,422 full-time employees as shown in the table below:

<b>Segment/Organization</b>	<b>Employees</b>
<b>Electric Segment</b>	
OTP <sup>(1)</sup>	728
<b>Manufacturing Segment</b>	
BTD	1,281
T.O. Plastics	204
Segment Total	1,485
<b>Plastics Segment</b>	
Northern Pipe	95
Vinyltech	78
Segment Total	173
<b>Corporate</b>	<b>36</b>
<b>Total</b>	<b>2,422</b>

<sup>(1)</sup> Includes all full-time employees of Otter Tail Power Company, including employees working at jointly-owned facilities. Labor costs associated with employees working at jointly-owned facilities are allocated to each of the co-owners based on their ownership interest.

At December 31, 2022, 354 employees of OTP were represented by local unions of the International Brotherhood of Electrical Workers under two separate collective bargaining agreements expiring on August 31, 2023 and October 31, 2023. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good. None of the employees of our other operating companies are represented by local unions.

The demographics of our workforce, including our Board of Directors, as of December 31, 2022 was as follows:

	<b>2022</b>		<b>2021</b>	
	<b>% Female</b>	<b>% Racially and Ethnically Diverse</b>	<b>% Female</b>	<b>% Racially and Ethnically Diverse</b>
Board of Directors <sup>(1)</sup>	36 %	9 %	20 %	10 %
CEO Direct Reports	33 %	— %	33 %	— %
Management	33 %	7 %	22 %	4 %
Non-Management Employees	16 %	19 %	17 %	19 %

<sup>(1)</sup> 2022 includes the new directors appointed to our Board effective January 1, 2023.

## **ELECTRIC**

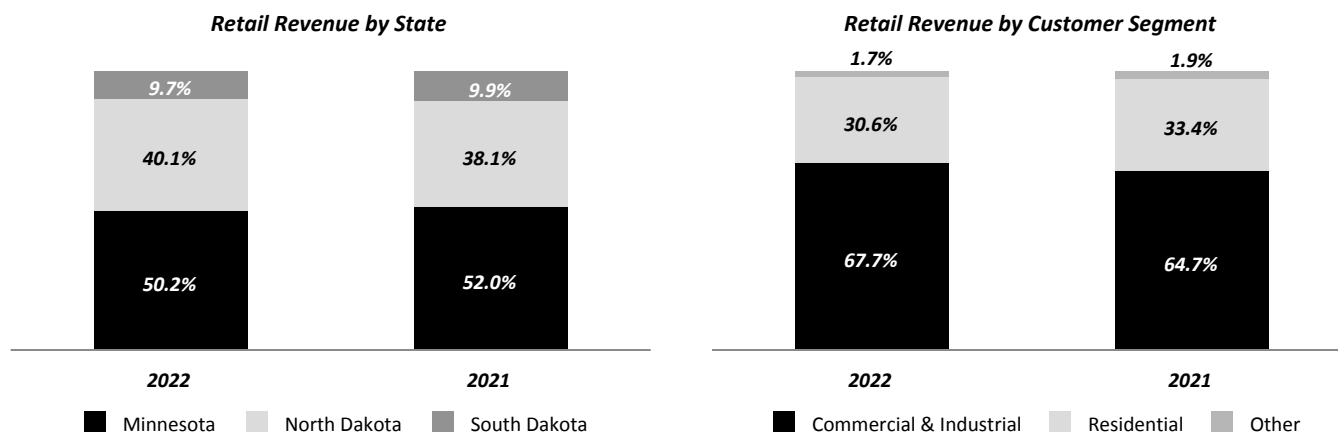
*Contribution to Operating Revenues: 38% (2022), 40% (2021), 50% (2020)*

OTP, headquartered in Fergus Falls, Minnesota, is a vertically integrated, regulated utility with generation, transmission and distribution facilities to serve its more than 133,000 residential, commercial and industrial customers in a service area encompassing approximately 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota.

## **CUSTOMERS**

Our service territory is predominantly rural and agricultural and includes over 400 communities, most of which have populations of less than 10,000. While our customer base includes relatively few large customers, sales to commercial and industrial customers are significant, with one industrial customer accounting for 11% and 10%, respectively, of segment operating revenues for the years ended December 31, 2022 and 2021.

The following charts summarize our retail electric revenues by state and by customer segment for the years ended December 31, 2022 and 2021:



In addition to retail revenue, our Electric segment also generates operating revenues from the transmission of electricity for others over the transmission assets we wholly or jointly own with other transmission service providers, and from the sale of electricity we generate and sell into the wholesale electricity market.

### COMPETITIVE CONDITIONS

Retail electric sales are made to customers in assigned service territories. As a result, most retail customers do not have the ability to choose their electric supplier. Competition is present in some areas from municipally owned systems, rural electric cooperatives and, in certain respects, from on-site generators and co-generators. Electricity also competes with other forms of energy.

Competition also arises from customers supplying their own power through distributed generation, which is the generation of electricity on-site or close to where it is needed in small facilities designed to meet local needs. Distributed energy resources can include combined heat and power, solar photovoltaic, wind, battery storage, thermal storage and demand-response technologies.

The degree of competition may vary from time to time depending on relative costs and supplies of other forms of energy and advances in technology. Irrespective of the competitive environment, we are focused on providing value to our customers and ensuring our retail rates remain among the lowest in the region and in the nation.

The following table presents our average retail rate per kilowatt-hour (kwh) by customer class and in total for the years ended December 31, 2022 and 2021:

<i>Revenue per kwh</i>	<b>2022</b>	<b>2021</b>
Residential	10.99 ¢	10.90 ¢
Commercial & Industrial	7.54 ¢	7.52 ¢
<b>Total Retail</b>	<b>8.41 ¢</b>	<b>8.47 ¢</b>

Wholesale electricity markets are competitive under the Federal Energy Regulatory Commission (FERC) open access transmission tariffs, which require utilities to provide nondiscriminatory access to all wholesale users. In addition, the FERC has established a competitive process for the construction and operation of certain new electric transmission facilities whereby electric transmission providers, including the Midcontinent Independent System Operator, Inc. (MISO), of which OTP is a member, are required to remove from their tariffs a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. The FERC is contemplating potential reforms for electric regional transmission planning, cost allocation and generator interconnection processes. While the ultimate regulatory outcome is uncertain at this time, changes to the regulatory framework could impact future transmission investments.

### Franchises

OTP has franchises to operate as an electric utility in substantially all of the incorporated municipalities it serves. Franchise rights generally require periodic renewal. No franchises are required to serve unincorporated communities in any of the three states OTP serves.

### GENERATION AND PURCHASED POWER

OTP primarily relies on company-owned generation, supplemented by power purchase agreements, to supply the energy to meet our customer needs. Wholesale market purchases and sales of electricity are used as necessary to balance supply and demand. Our mix of owned generation and wholesale market energy purchases to meet customer demand are impacted by wholesale energy prices and the relative cost of each energy source.

As of December 31, 2022, OTP's wholly- or jointly-owned plants and facilities, as well as in place power purchase agreements, and their dependable kilowatt (kW) capacity were:

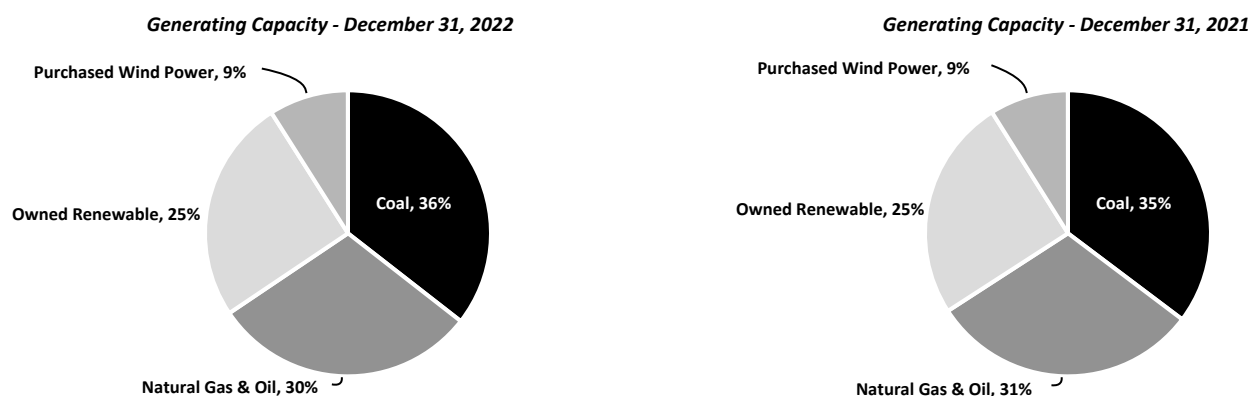
	<i>Capacity / Purchased Power in kW</i>
<b>Owned Generation:</b>	
<b>Baseload Plants</b>	
Big Stone Plant <sup>(1)</sup>	258,000
Coyote Station <sup>(2)</sup>	148,200
Total Baseload Plants	406,200
<b>Combustion Turbine and Small Diesel Units</b>	
Astoria Station	242,200
All Other	101,500
Total Combustion Turbine and Small Diesel Units	343,700
<b>Owned Wind Facilities (rated at nameplate)</b>	
Merricourt Wind Energy Center	150,000
Luverne Wind Farm	49,500
Ashtabula Wind Center	48,000
Langdon Wind Center	40,500
Total Owned Wind Facilities	288,000
<b>Hydroelectric Facilities</b>	2,500
<b>Total Owned Generation Capacity</b>	<b>1,040,400</b>
<b>Power Purchase Agreements:</b>	
<b>Purchased Wind Power (rated at nameplate and greater than 2,000 kW)</b>	
Ashtabula Wind III <sup>(3)</sup>	62,400
Edgeley	21,000
Langdon	19,500
<b>Total Purchased Wind</b>	<b>102,900</b>
<b>Total Generating Capacity</b>	<b>1,143,300</b>

<sup>(1)</sup> Reflects OTP's 53.9% ownership percentage of jointly-owned facility.

<sup>(2)</sup> Reflects OTP's 35.0% ownership percentage of jointly-owned facility.

<sup>(3)</sup> OTP acquired the assets of the Ashtabula III wind farm on January 3, 2023.

The following charts summarize the percentage of our generating capacity by source, including owned and jointly-owned facilities and through power purchase arrangements, as of December 31, 2022 and 2021:



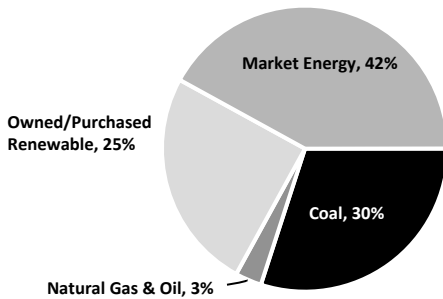
Under MISO requirements, OTP is required to provide sufficient capacity through wholly- or jointly-owned generating capacity or power purchase agreements to meet its monthly weather-normalized forecast demand, plus a reserve obligation.

On August 31, 2022, FERC issued an order to approve MISO's proposal to revise its resource adequacy requirement, including the adoption of a seasonal resource adequacy construct rather than a single requirement based on a summer peak. MISO proposed the seasonal adequacy construct to address significant increases in emergency declarations that occur throughout the year, driven by factors including declining excess reserve margin, generation retirements, reliance on intermittent resources and outages resulting from extreme weather events. These new provisions will be implemented in the 2023/2024 planning year. Under the new seasonal resource adequacy construct, the seasonal reserve margin requirements deviate significantly from MISO's 2022/2023 annual planning reserve margin requirements. For planning year 2022/2023, the last year under the

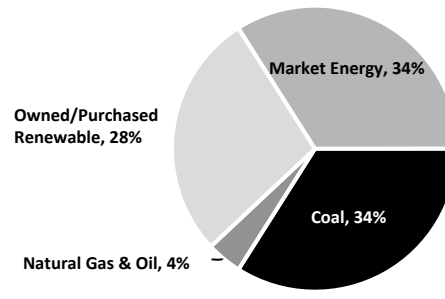
annual construct, our required planning reserve margin was 8.7%. For planning year 2023/2024, under the new seasonal construct, our planning reserve margin requirements range between 7.4% and 25.5%, depending on the season.

The following charts summarize the percentage of retail kwh sold by source during the years ended December 31, 2022 and 2021:

*Retail kwh Sold by Source - Year Ended December 31, 2022*



*Retail kwh Sold by Source - Year Ended December 31, 2021*



### Capacity Retirements and Additions

**Hoot Lake Plant**, our 142-megawatt coal-fired power plant in Fergus Falls, Minnesota was retired in mid-2021.

As part of our investment plan to meet our future energy needs, the following significant projects are at various stages of planning and construction or have been recently completed:

**Merricourt Wind Energy Center (Merricourt)** is a 150-megawatt wind farm located in southeastern North Dakota. The facility was placed into commercial operation in December 2020, with a total cost of approximately \$260 million.

**Astoria Station Natural Gas Plant (Astoria)** is a 245-megawatt simple cycle natural gas combustion turbine generation facility near Astoria, South Dakota. The facility was placed into commercial operation in February 2021, with a total cost of approximately \$160 million.

**Hoot Lake Solar** is a 49-megawatt solar farm under construction on and around our Hoot Lake Plant property in Fergus Falls, Minnesota, with an anticipated cost of approximately \$60 million. We anticipate the facility will be in commercial operation by the end of 2023.

**Ashtabula III Wind Farm** is a 62-megawatt wind farm located in eastern North Dakota. The facility was purchased for approximately \$50 million in January 2023. Prior to the purchase of the wind farm assets, we were purchasing the wind-generated electricity from the wind farm pursuant to a power purchase agreement.

### ENERGY TRANSITION

OTP is committed to transitioning to a lower-carbon and increasingly clean energy future, while maintaining affordable and reliable electricity to serve our customers. We have developed the following goals in furtherance of our efforts to support the energy transition:

Own or purchase energy generation that's **more than 50% renewable by 2025**.

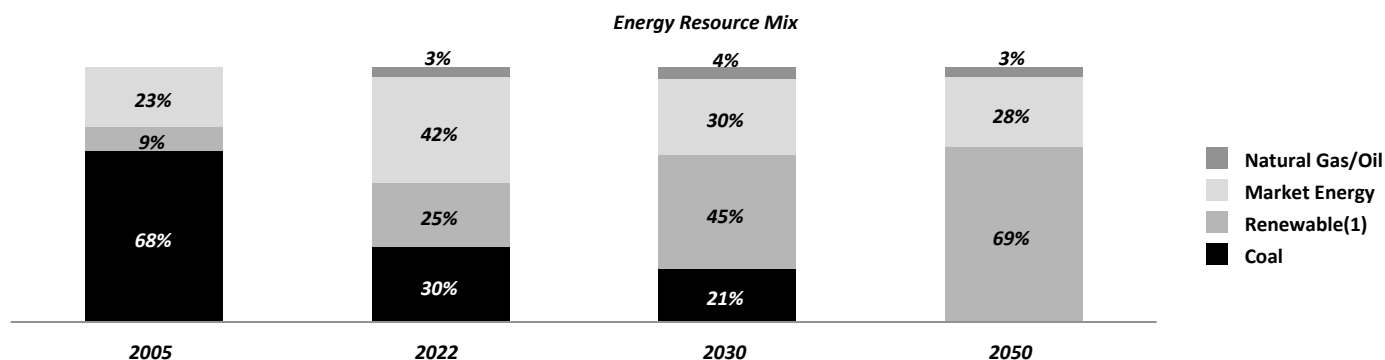
**Reduce carbon emissions** from owned generation resources **50% by 2025** from 2005 levels.

**Reduce carbon emissions** from owned generation resources **97% by 2050** from 2005 levels.

To date, we have undertaken numerous initiatives to reduce our carbon footprint and mitigate greenhouse gas (GHG) emissions in the process of generating electricity for our customers. Our initiatives include increasing the efficiency of our plants, retiring Hoot Lake Plant, adding renewable energy to our resource mix and sponsoring energy conservation programs.

From 2005 through 2022, we have reduced our carbon dioxide (CO<sub>2</sub>) emissions approximately 43% and increased the amount of renewable generation resources we own or purchase through power purchase agreements by approximately 370-megawatts. Our future resource plans to deliver affordable, reliable, and increasingly clean energy to our customers include the addition of 49-megawatts of solar energy from Hoot Lake Solar in 2023 and repowering various wind farm assets to increase their efficiency and output.

The following chart depicts our energy resource mix, which is the electricity we use to serve our customers, in 2005 and 2022 and the projected mix in 2030 and 2050. The amounts include energy generated from owned resources, procured through power purchase agreements and energy purchased in the wholesale market:



### Inflation Reduction Act

On August 16, 2022, the Inflation Reduction Act of 2022 (IRA) was signed into law. The IRA includes funding for climate and clean energy investments and other provisions affecting corporate taxpayers. The climate and clean energy provisions of the IRA include, among other items, i) the extension of the traditional production tax credits (PTC) and investment tax credits (ITC) for renewable technologies (including wind and solar) if construction is begun before 2025, along with elimination of the existing phase-down of the PTC and ITC, and transitions to a new technology neutral credit for property placed in service after 2024, ii) a new PTC for sale of domestically produced electricity with a GHG emission rate of not greater than zero produced at a qualifying facility placed in service after 2024, iii) a new ITC for investment in qualifying zero-emission electricity generation facilities or energy storage technology placed in service after 2024, and iv) alternative ways to monetize renewable tax credits by allowing certain entities to sell tax credits to third parties.

The tax incentives provided under the IRA are intended to incentivize the transition to a cleaner energy economy and to reduce GHG emissions from the electric utility industry. These financial incentives could impact the planning of our future generation resources and our long-term capital spending plan. See the Integrated Resource Plan (IRP) section below for additional details on how the passage of the IRA has impacted our recently filed IRP.

### RESOURCE MATERIALS

Coal is the principal fuel burned at our jointly-owned Big Stone and Coyote Station generating plants. Coyote Station, a mine-mouth facility, burns North Dakota lignite coal. Big Stone Plant burns western subbituminous coal transported by rail. We source coal for our coal-fired power plants through requirements contracts which do not include minimum purchase requirements but do require all coal necessary for the operation of the respective plant to be purchased from the counterparty. Our coal supply contracts for our Big Stone Plant and Coyote Station have expiration dates in 2024 and 2040.

The supply agreement between the Coyote Station owners, including OTP, and the coal supplier includes provisions requiring the Coyote Station owners to purchase the membership interests and pay off or assume loan and lease obligations of the coal supplier, as well as complete mine closing and post-mining reclamation, in the event of certain early termination events and at the expiration of the coal supply agreement in 2040. See below and Note 1 to our consolidated financial statements included in this report on Form 10-K for additional information.

Coal is transported to our non-mine-mouth facility, Big Stone Plant, by rail and is provided under a common carrier rate which includes a mileage-based fuel surcharge.

We purchase natural gas for use at our combustion turbine facilities based on anticipated short-term resource needs. We procure natural gas from multiple vendors at spot prices in a liquid market primarily under firm delivery contracts.

### TRANSMISSION AND DISTRIBUTION

Our transmission and distribution assets deliver energy from energy generation sources to our customers. In addition, we earn revenue from the transmission of electricity over our wholly- or jointly-owned transmission assets for others under approved rate tariffs. As of December 31, 2022, we were the sole or joint owner of nearly 15,000 miles of transmission and distribution lines.

### Midcontinent Independent System Operator

MISO is an independent, non-profit organization that operates the transmission facilities owned by other entities, including OTP, within its regional jurisdiction and administers energy and generation capacity markets. MISO has operational control of our transmission facilities above 100 kilovolts (kV). MISO seeks to optimize the efficiency of the interconnected system, provide solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions.

In 2022, MISO approved several projects within the first tranche of its long-range transmission plan, which includes two new 345 kV transmission projects and a project to upgrade an existing transmission line. OTP will have a varying level of ownership interest in these projects, which will be completed over several years, and our total capital investment in these projects is anticipated to be approximately \$390 million.

## SEASONALITY

Electricity demand is affected by seasonal weather differences, with peak demand occurring in the summer and winter months. As a result, our Electric segment operating results regularly fluctuate on a seasonal basis. In addition, fluctuations in electricity demand within the same season but between years can impact our operating results. We monitor the level of heating and cooling degree days in a period to assess the impact of weather-related effects on our operating results between periods.

## PUBLIC UTILITY REGULATION

OTP is subject to regulation of rates and other matters in each of the three states in which it operates and by the federal government for, among other matters, the interstate transmission of electricity. OTP operates under approved retail electric tariff rates in all three states it serves. Tariff rates are designed to recover plant investments, a return on those investments, and operating costs. In addition to determining rate tariffs, state regulatory commissions also authorize return on equity (ROE), capital structure, and depreciation rates of our plant investments. Decisions by our regulators significantly impact our operating results, financial position, and cash flows.

Below is a summary of the regulatory agencies with jurisdiction of electric rates over OTP covered by each regulatory agency:

<i>Regulatory Agency</i>	<i>Areas of Regulation</i>
Minnesota Public Utilities Commission (MPUC)	Retail rates, issuance of securities, depreciation rates, capital structure, public utility services, construction of major facilities, establishment of exclusive assigned service areas, contracts with subsidiaries and other affiliated interests and other matters. Selection or designation of sites for new generating plants (50,000 kW or more) and routes for transmission lines (100 kV or more). Review and approval of fifteen-year Integrated Resource Plan.
North Dakota Public Service Commission (NDPSC)	Retail rates, certain issuances of securities, construction of major utility facilities and other matters. Approval of site and routes for new electric generating facilities (>500 kW for wind generating facilities; >50,000 kW for non-wind generating facilities) and high voltage transmission lines (>115 kV). Review and approval of fifteen-year Integrated Resource Plan.
South Dakota Public Utilities Commission (SDPUC)	Retail rates, public utility services, construction of major facilities, establishment of assigned service areas and other matters. Approval of sites and routes for new electric generating facilities (100,000 kW or more) and most transmission lines (115 kV or more).
Federal Energy Regulatory Commission (FERC)	Wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, hydroelectric licensing and accounting policies and practices. Compliance with North American Electric Reliability Corporation (NERC) reliability standards, including standards on cybersecurity and protection of critical infrastructure.

In addition to base rates, which are established through periodic rate case proceedings within each state jurisdiction, there are other mechanisms for recovery of plant investments, including a return on investment and operating expenses, between rate cases. The following table summarizes these recovery mechanisms:

<i>Recovery Mechanism</i>	<i>Jurisdiction(s)</i>	<i>Additional Information</i>
Fuel Clause Adjustment (FCA)	MN, ND, SD	Provides for periodic billing adjustments for changes in prudently incurred costs of fuel and purchased power. In North and South Dakota, fuel and purchased power costs are generally adjusted on a monthly basis with over or under collections from the previous month applied to the next monthly billing. In Minnesota, fuel and purchased power costs are estimated on an annual basis and the accumulated difference between actual and estimated cost per kwh are refunded or recovered, subject to regulatory approval, in subsequent periods.
Transmission Cost Recovery Rider (TCR)	MN, ND, SD	Provides for the recovery of costs outside of a general rate case for investments in new or modified electric transmission assets and certain MISO transmission service and related costs.
Environmental Cost Recovery Rider (ECR)	MN, ND, SD	Provides for the recovery of costs outside of a general rate case for investments in certain environmental improvement projects.
Renewable Resource Rider (RRR)	MN, ND	Provides for the recovery of costs outside of a general rate case for investments in certain new renewable energy projects.
Conservation Improvement Program (CIP)	MN	Under Minnesota law, OTP is required to save 1.75% of its gross retail energy revenues through the energy conservation and optimization program. Recovery of these costs outside of a general rate case occurs through the CIP rider.
Electric Utility Infrastructure Costs Rider (EUIC)	MN	Provides for the recovery of costs for investments made to replace or modify existing infrastructure if the replacement or modification conserves energy or uses energy more efficiently.
Advanced Meter and Distribution Technology Cost Recovery Rider (AMDT)	ND	Provides for the recovery of costs for advanced metering infrastructure, outage management systems and demand response projects.
Generation Cost Recovery Rider (GCR)	ND	Provides for the recovery of costs outside of a general rate case for investments in new generation facilities.
Energy Efficiency Plan (EEP)	SD	Provides for the recovery of costs from energy efficiency investments.
Phase-In Rider (PIR)	SD	Provides for the recovery of costs outside of a general rate case for investments in new generation facilities and advanced grid infrastructure.

### **Integrated Resource Plan**

Under Minnesota law, utilities are required to submit for approval by the MPUC a 15-year advance IRP. An IRP is a set of resource options a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the utility's supply and demand circumstances, and the extent to which each resource option would be used to meet those service needs. The MPUC's findings of fact and conclusions regarding IRPs are considered to be prima facie evidence, subject to rebuttal, in future rate reviews and other proceedings. Typically, IRPs are submitted every two years.

In 2021, the North Dakota Legislative Assembly enacted a provision requiring investor-owned electric utilities to submit an IRP to the NDPSC and granted the NDPSC the authority to adopt rules and regulations for the preparation and submission of IRPs. The NDPSC's rules and regulations were finalized and became effective on January 1, 2023. Under the finalized regulation, utilities are required to submit, for approval by the NDPSC, a 15-year advance IRP every three years.

On September 1, 2021, OTP filed its 2022 IRP concurrently with regulators in Minnesota, North Dakota and South Dakota. The 2022 IRP included OTP's preferred plan for meeting customers' anticipated capacity and energy needs while maintaining system reliability and affordable electric service rates, based on the information available at that time. The preferred plan as outlined in the 2022 IRP included the addition of dual fuel capabilities at our Astoria natural gas plant, the addition of 150-megawatts of solar generation, the addition of 100-megawatts of wind generation, and the commencement of the process of withdrawing from our 35 percent ownership interest in Coyote Station, a jointly-owned, coal-fired generation plant, by December 31, 2028.

Subject to regulatory approval, the preferred plan proposed to create a regulatory asset as a vehicle to recover costs related to a future withdrawal from Coyote Station, including the net book value of the plant on the withdrawal date, anticipated decommissioning costs and any required costs incurred as a result of an early termination of the existing lignite sales agreement (LSA), under which Coyote Station acquires all of its lignite coal from a nearby mine. As part of the filing, OTP developed an estimate of the reasonably foreseeable costs of withdrawing from Coyote Station at the end of 2028 of \$68.5 million. These costs may differ from actual results due to the uncertainty and timing of future events associated with the terms and conditions of a withdrawal.

On October 14, 2022, OTP submitted a supplemental filing to update its 2022 IRP, requesting the procedural schedule in Minnesota be amended to allow additional time to update our resource modeling given significant changes in the energy industry since the original 2022 IRP filing, while maintaining the original procedural schedule as it relates to adding dual fuel capability at Astoria. Our original filing proposed fuel oil as the secondary on-site fuel at Astoria and our supplemental filing reflects revised cost estimates and proposes liquified natural gas as the most cost-effective secondary fuel source. The primary changes and events which led to OTP's request include FERC's approval of MISO's new seasonal

resource adequacy construct, MISO's proposal to significantly increase winter and spring planning reserve margins, and enactment of the IRA. A notice of the request submitted to the MPUC was also provided to the NDPSC and SDPUC.

On November 1, 2022, the MPUC approved OTP's requested changes to the procedural schedule for the 2022 IRP. OTP plans to file an updated resource plan in March 2023, pursuant to the amended schedule. In conjunction with the updated resource plan, OTP's preferred plan could change based on the results of updated resource modeling incorporating the factors listed above, as well as other changes. A change to the preferred plan could ultimately impact the nature, timing and amount of future capital investments, as well as the potential for OTP's withdrawal from Coyote Station.

#### **Capital Structure Petition**

Minnesota law requires an annual filing of a capital structure petition with the MPUC. In this filing the MPUC reviews and approves OTP's capital structure. Once approved, OTP may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved petition. OTP's current capital structure approved by the MPUC on November 8, 2022, allows for an equity-to-total-capitalization ratio between 47.5% and 58.0%, with total capitalization not to exceed \$1.8 billion.

#### **Renewable Energy Standard**

Minnesota has a renewable energy standard requiring utilities to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 25% by 2025 and 55% by 2035. Qualifying renewable sources are classified as wind, hydropower, hydrogen, and certain biomass generation. We met the current renewable sources requirements with a combination of owned renewable generation and purchases from renewable generation sources. Minnesota law also requires 1.5% of total Minnesota retail electric sales by public utilities to be supplied by solar energy. For a public utility with between 50,000 and 200,000 retail electric customers, such as OTP, at least 10% of the 1.5% requirement must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less. OTP plans to purchase Solar Renewable Energy Credits to meet its obligations until its Hoot Lake Solar and other solar projects are complete and operational. Under certain circumstances, and after consideration of customers' utility costs and reliability issues, the MPUC may modify or delay implementation of the standards. We are evaluating potential options for maintaining compliance and meeting the solar energy standard beyond 2022.

#### **Minnesota Clean Energy Bill**

In February 2022, Minnesota enacted the Clean Energy Bill, which requires electric utilities to generate or procure sufficient electricity from carbon-free resources, to provide retail customers in Minnesota with at least the following percentages of carbon-free electric energy: 80% by 2030, 90% by 2035, and 100% by 2040. Carbon-free resources include wind, solar, hydropower, and nuclear generation. To provide flexibility, the law allows electric utilities to use renewable energy credits (RECs) to offset carbon emissions and for the MPUC to consider whether a regulated utility's requirement to meet established standards should be delayed due to affordability or reliability impacts. OTP is in the process of reviewing its plan for compliance with the newly enacted law.

#### **ENVIRONMENTAL REGULATION**

OTP is subject to stringent federal and state environmental standards and regulations regarding, among other things, air, water and solid waste pollution. OTP's facilities have been designed, constructed and, as necessary, updated to operate in compliance with applicable environmental regulations. However, new or amended laws and regulations or changes in interpretations of current laws and regulations may require additional pollution control equipment or emission reduction measures and there can be no assurance that our facilities will remain economic to operate. Prudent expenditures incurred to comply with environmental regulations are eligible to be recovered in rates authorized by regulators in jurisdictions in which we operate; however, there can be no assurance that future costs will be authorized for recovery. Alternatively, additional pollution control equipment or other emission reduction measures may prove to be uneconomic potentially leading to the exiting of a facility earlier than originally planned. As it relates to our jointly-owned facilities, we may determine it is necessary to transfer, sell or otherwise divest of our ownership, or the ownership group may determine the early closure or repurposing of a facility is necessary.

For the five-year period ended December 31, 2022, OTP invested approximately \$10.4 million in environmental control facilities, including \$0.4 million in 2022. Our construction budget for the next five years includes approximately \$6.1 million of capital investments in environmental control equipment. The timing and amount of our expenditures may change as the regulatory environment changes.

Among current regulatory requirements, the federal Regional Haze Rule (RHR) could have the most significant impact on our operating results, financial condition and liquidity.

The Environmental Protection Agency (EPA) adopted the RHR in 1999 as an effort to improve visibility in national parks and wilderness areas. The RHR requires states, in coordination with the EPA and other governmental agencies, to develop and implement state implementation plans (SIPs) which work towards achieving natural visibility conditions by the year 2064, to set goals to ensure reasonable progress is being made, and to periodically evaluate whether those goals and progress are on track or whether additional emission reductions are appropriate. The second RHR implementation period covers the years 2018-2028. States are required to submit a state implementation plan to assess reasonable progress with the RHR and determine what additional emission reductions are appropriate, if any.

Coyote Station is subject to assessment in the second implementation period under the North Dakota SIP for the RHR. The North Dakota Department of Environmental Quality (NDDEQ) submitted its proposed SIP to the EPA for approval in August 2022. In its plan, the NDDEQ concluded it is not reasonable to require additional emission controls during this planning period. The EPA submitted comments during the development of the SIP requesting NDDEQ to reassess its determination for Coyote Station. The EPA is anticipated to take proposed action and potential final action on the SIP in 2023. See Note 13 to our consolidated financial statements for additional information.

## Climate Change and Greenhouse Gas Regulation

Global climate change presents a significant energy and environmental policy challenge. Combustion of fossil fuels for the generation of electricity is a considerable source of CO<sub>2</sub> emissions, which is the primary GHG emitted by our utility operations. The federal government and many states are pursuing climate policies to regulate GHG emissions as part of a broad-based effort to limit global warming.

In February 2021, the U.S. rejoined the United Nations Framework Convention on Climate Change (the Paris Agreement), which is a legally binding international treaty on climate change adopted by over 190 countries. The goal of the Paris Agreement is to limit the global temperature increase to well below 2° Celsius compared to pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5° Celsius. The Biden Administration has announced the goal of reducing GHG emissions by 50 to 52 percent from 2005 levels in 2030 and to reach 100 percent carbon pollution-free electricity by 2035 as part of the U.S. plan to achieve the goals under the Paris Agreement.

In February 2022, Minnesota enacted the Clean Energy Bill, which requires electric utilities to generate or procure sufficient electricity from carbon-free resources to provide retail customers in Minnesota with at least the following percentages of carbon-free electric energy: 80% by 2030, 90% by 2035, and 100% by 2040.

The implementation of climate change programs, such as the Paris Agreement, the Minnesota Clean Energy Bill, and other federal or state regulations targeting GHG emissions may have a significant impact on our utility business. Specific regulatory measures to address climate change continue to evolve. In January 2021, the EPA's Affordable Clean Energy Rule (ACE Rule), which required states to develop plans for GHG emissions from coal-fired power plants, was vacated by the U.S. Court of Appeals for the District of Columbia Circuit. In October 2021, the U.S. Supreme Court agreed to hear a consolidated challenge to the Court of Appeals decisions. In June 2022, the U.S. Supreme Court issued its opinion in the case of *West Virginia v. EPA*, finding that in Section 111(d) of the Clean Air Act, Congress did not grant the EPA the authority to broadly regulate GHG emissions under the Clean Air Act, including the setting of emissions limits for existing power plants based on the power sector's ability to shift to cleaner renewable energy sources (a process known as "generation shifting"). The Supreme Court found that the authority to regulate issues that have broad economic or political consequences (known as the "major questions doctrine") requires explicit Congressional authorization in law. In the first half of 2023, the EPA is expected to issue a proposed rule under Clean Air Act section 111(d), replacing or revising the previously proposed ACE rule. Although this future proposed rule is subject to the constraints of the Supreme Court's *West Virginia v. EPA* decision, the rule nevertheless has the potential to impact the emissions controls needed at OTP's coal-fired power plants.

While the future financial impact of any current, proposed, or pending litigation or regulation of GHG or other emissions is unknown at this time, any capital or operating costs incurred for additional pollution control equipment or emission reduction measures could materially adversely impact our future operating results, financial position, and liquidity unless such costs could be recovered through related rates and/or future market prices for energy.

## MANUFACTURING

*Contribution to Operating Revenues: 27% (2022), 28% (2021), 27% (2020)*

Manufacturing consists of businesses engaged in the following activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components and extruded raw material stock. The following is a brief description of each of these businesses:

**BTD Manufacturing, Inc. (BTD)**, with headquarters located in Detroit Lakes, Minnesota, provides metal fabrication services for custom machine parts and metal components through metal stamping, tool and die, machining, tube bending, welding and assembly in its facilities in Detroit Lakes and Lakeville, Minnesota, Washington, Illinois and Dawsonville, Georgia.

**T.O. Plastics, Inc. (T.O. Plastics)**, with facilities in Otsego and Clearwater, Minnesota, manufactures extruded and thermoformed plastic products, including custom parts for customers in several industries and its own line of horticulture containers. Examples of products produced include clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts.

## CUSTOMERS

Our metal fabrication business primarily serves Midwestern and Southeastern U.S. manufacturers in the recreational vehicle, lawn and garden, agricultural, construction, and industrial and energy equipment end markets. Our plastic products business serves primarily U.S. customers in the horticulture, medical and life sciences, industrial, recreational and electronics industries. The principal method of production distribution is by direct shipment to our customers through direct customer pick-up or common carrier ground transportation.

No single customer or product of our Manufacturing segment businesses accounted for 10% or more of our consolidated operating revenues in 2022. However, the top three customers combined to account for 50% and 46% of our 2022 and 2021 Manufacturing segment operating revenues, respectively.

## COMPETITIVE CONDITIONS

The various markets in which we compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources, excess capacity, labor advantages and larger marketing, research and development staffs and facilities than our own.

We believe the principal competitive factors in our Manufacturing segment are product performance, quality, price, technical innovation, cost effectiveness, customer service and breadth of product line. We intend to continue to compete based on high-performance products, innovative production technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

## RESOURCE MATERIALS

We use raw materials in the products we manufacture, including, among others, steel, aluminum, and polystyrene and other plastics resins. Managing price volatility and ensuring raw material availability are important aspects of our business. We attempt to pass increases in the costs of these raw materials through to our customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins. Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of our Manufacturing segment as it reduces their ability to mitigate the costs associated with excess material.

## ENVIRONMENTAL REGULATION

Our manufacturing businesses are subject to environmental, health and safety laws and regulations, including those governing discharges to air and water, the management and disposal of hazardous substances, the cleanup of contaminated sites and health and safety matters.

## PLASTICS

*Contribution to Operating Revenues: 35% (2022), 32% (2021), 23% (2020)*

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The following is a brief description of these businesses:

**Northern Pipe Products, Inc. (Northern Pipe)**, located in Fargo, North Dakota, manufactures and sells PVC pipe for municipal water, rural water, wastewater, storm drainage systems and other uses in the northern, midwestern, south-central and western regions of the United States as well as central and western Canada.

**Vinyltech Corporation (Vinyltech)**, located in Phoenix, Arizona, manufactures and sells PVC pipe for municipal water, wastewater, water reclamation systems and other uses in the western, northwest and south-central regions of the United States.

PVC pipe is manufactured through a process known as extrusion. During this process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is pulled through a series of water-cooling tanks, marked to identify the type of pipe and cut to finished lengths.

## CUSTOMERS

PVC pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for our PVC pipe products consist primarily of wholesalers and distributors and the principal method for distribution of our products is by common carrier ground transportation. No single customer of the PVC pipe companies accounted for 10% or more of our consolidated operating revenues in 2022. However, two customers, both of which are distributors of PVC pipe, combined to account for 46% and 50% of our 2022 and 2021 Plastics segment operating revenues, respectively.

## COMPETITIVE CONDITIONS

The plastic pipe industry is fragmented and competitive due to the number of producers, the small number of raw material suppliers and the fungible nature of the product. Due to shipping costs, competition is usually regional instead of national in scope. The principal factors of competition are price, customer service and product performance. We compete not only against other plastic pipe manufacturers, but also ductile iron, high-density polyethylene, steel and concrete pipe producers. Pricing pressure will continue to affect our operating margins in the future.

We will continue to compete based on our high-quality products, cost-effective production techniques and close customer relations and support.

## RESOURCE MATERIALS

PVC resins are acquired in bulk and shipped to our facilities by rail. There are four vendors from which we can source our PVC resin requirements. In 2022 we sourced all of our PVC resin from two vendors. Our contractual arrangements to acquire resin generally include estimated annual order quantities with no required minimum purchases, and include variable pricing based on market prices for resin. The supply of PVC resin may also be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region. These plants are subject to the risk of damage and production shutdowns because of exposure to hurricanes or other extreme weather events that occur in this part of the United States. The loss of a key vendor, or any interruption or delay in the supply of PVC resin could disrupt the ability of our Plastics segment businesses to manufacture products, cause customers to cancel orders or result in increased expenses for obtaining PVC resin from alternative sources, if such sources were available. We believe we have good relationships with our key raw material vendors.

Due to the commodity nature of PVC resin and PVC pipe and the dynamic supply and demand factors worldwide, historically the markets for both PVC resin and PVC pipe have been very cyclical with significant fluctuations in prices and gross margins.

In addition to PVC resin, we use certain other materials, such as stabilizers, gaskets and lumber, in the process of manufacturing and shipping our PVC pipe products. We generally source these materials from a limited number of suppliers, and supply chain constraints or disruptions related to these materials could disrupt our ability to manufacture or ship products and could result in increased costs.

## SEASONALITY

Demand for our PVC pipe products can be impacted by seasonal weather differences, with generally lower sales volumes realized in the first quarter of the year when cold temperatures and frozen ground across the northern portion of our footprint can delay or prevent construction activity and consequently delay or prevent customer orders of PVC pipe.

**ENVIRONMENTAL REGULATION**

Our plastics businesses are subject to environmental, health and safety laws and regulations, including those governing discharges to air and water, the management and disposal of hazardous substances, the cleanup of contaminated sites and health and safety matters.

## ITEM 1A. RISK FACTORS

### RISK FACTORS AND CAUTIONARY STATEMENTS

Our businesses are subject to various risks and uncertainties. Any of the risks described below or elsewhere in this report on Form 10-K or in our other SEC filings could materially adversely affect our business, operating results, financial condition and liquidity. Additional risks and uncertainties we are not presently aware of or that we currently consider immaterial may also affect our business, operating results, financial condition and liquidity.

#### Oversight of Risk and Related Processes

A key accountability of the Board of Directors is the oversight of material risk. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of significant and emerging risks. Management identifies and analyzes risks to determine the impact and other attributes such as timing, likelihood and management control. Identification and analysis occur formally through an assessment of significant and emerging risks conducted by senior management, the financial disclosure process, and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through the development of goals and key performance indicators, which include risk identification to determine barriers to implementing our strategy. We promote a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of business ethics and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. We manage and further mitigate risks through formal risk management structures, including a management executive risk committee and internal business functions such as internal audit/business risk management and legal. Management communicates regularly with our Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to our Board of Directors which provides information on the risks management believes are material, including the earnings impact, timing, likelihood and management control. The Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of Otter Tail Corporation. The Board of Directors regularly reviews management's top risk assessment and analyzes areas of existing and future risks and opportunities. Finally, the Board of Directors conducts an annual strategy session where our future plans and initiatives are reviewed.

### OPERATIONAL RISKS

#### Our strategy includes large capital investments, which are subject to risks.

Our business strategy includes major capital investments at our existing companies. Our capital investment program planned for the next five years includes Electric segment investments in renewable generation, transmission asset additions and upgrades, and technology and infrastructure projects, and Manufacturing and Plastics segments investments in facilities, equipment and machinery. These capital projects are planned years in advance of their in-service dates and are subject to various risks including: obtaining necessary permits, licenses and timely approvals; adverse changes in regulatory treatment or public policy; changes in commodity pricing, equipment and construction costs; technology changes; delivery delays of critical materials and components; delays caused by construction accidents, injuries or public health crises; adverse weather conditions; unforeseen product defects; limited access to capital; and other adverse conditions. Capital investments in our Electric segment require regulatory approval and are subject to the risks of not being granted timely or allowed to be fully recovered. The inability to complete capital projects on budget and in a timely manner could adversely impact our operating results and financial condition.

#### Our acquisition or divestiture strategies are subject to risk and could adversely impact our financial position and operating results.

As part of our business strategy, we continually assess our mix of businesses and potential strategic acquisitions or divestitures. This investment strategy is subject to various risks including the ability to identify appropriate acquisition candidates or successfully negotiate and finance any acquisitions. In addition, difficulties in integrating the operations, services, products and personnel of the acquired business, and the potential loss of key employees, customers and suppliers of the acquired business could adversely impact our financial condition and operating results.

The sale of any of our businesses may result in the recognition of a loss if the business is sold for less than its book value and may expose us to risk arising from indemnification obligations that arose out of the conduct of the business prior to the sale. These obligations may include warranty and environmental obligations or the recoverability of certain assets sold as part of the transaction. Unforeseen costs related to these obligations could impact our operating results.

#### Weather impacts, including normal seasonal fluctuation and extreme weather events, could adversely affect our operating results.

Our Electric segment business is seasonal and weather patterns can have a material impact on our financial performance. Demand for electricity is normally greater in the winter and summer months. Unusually mild summers and winters could have an adverse effect on our financial condition and results of operations. Weather can also have a significant impact on our Plastics segment businesses as most U.S. PVC resin production plants are located in the Gulf Coast region, which is prone to seasonal hurricane activity and other extreme weather events. Our access to PVC resin may be impacted by the volume and magnitude of hurricane and storm activity in this region. In addition, our Plastics segment businesses can be affected by weather prohibiting or delaying construction projects at any time of the year in any geography, but specifically times of the year when frozen ground and cold temperatures in many parts of the country can delay construction projects, all of which can result in reduced customer demand.

Our businesses are located in areas that could be subject to natural disasters such as severe snow and ice storms, tornadoes, flooding and fires. These factors could result in interruption of our business and damage to our facilities. An extreme weather event within our utility service area could directly affect our capital assets, causing disruption in service to customers and result in repair or replacement costs, due to downed wires and poles or damage to other operating equipment.

In addition to variations in seasonal weather patterns, more widespread climate change may also create physical and financial risk to our businesses. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation

patterns, changes to ground and surface water availability and other phenomena, could affect some or all of our operations. Severe weather or other natural disasters related to climate change could be destructive and result in increased costs and disruptions in our operations. Extreme weather conditions, such as uncommonly long periods of high or low ambient temperature, generally require more utility system backup, adding to costs and contributing to increased system stress on our utility infrastructure, which could cause service interruptions.

**The loss of, or significant reduction in revenue from, any of our key customers could have an adverse effect on our operating results.**

While no single customer provided more than 10% of our consolidated operating revenues, each of our segments have customers which accounted for over 10% of the segment's operating revenues. In 2022, one customer accounted for 11% of Electric segment revenues, three customers combined to account for 50% of Manufacturing segment operating revenues and two customers combined to account for 46% of Plastics segment operating revenues. The loss of any one of these customers or a significant decline in sales to these customers, would have a significant negative impact on the segment's financial condition and operating results, and could have a significant negative impact on the Company's consolidated financial condition, operating results and liquidity.

Electric segment operating revenues also include sales to a customer that is a developer and operator of data centers which serve the high performance computing industry, with a concentration of customers involved in cryptocurrency mining and related activities. Customer demand from their cryptocurrency mining customers can directly impact our customer's demand for electricity. The cryptocurrency industry is highly volatile, and a significant decrease in cryptocurrency mining demand could have a negative impact on our customer's demand for electricity, and therefore negatively impact our operating revenues.

**We are subject to counterparty credit risk.**

We extend credit to our customers in the ordinary course of business in each of our operating segments. Our customers' ability to pay depends on a variety of factors including macroeconomic conditions, local economic conditions including unemployment rates, and industry conditions in which our customers operate. Increased customer delinquencies and bad debts could adversely impact our operating results and liquidity.

**Our operations are subject to environmental, health and safety laws and regulations.**

We are subject to numerous federal, state, and local environmental, health and safety laws and regulations governing, among other things, discharges to air and water, natural resources, hazardous waste and toxic substances, the cleanup of contaminated sites, and health and safety matters. Our failure to comply with applicable laws and regulations could result in civil or criminal fines or penalties, enforcement actions, and regulatory or judicial orders enjoining or curtailing operations or requiring corrective measures, which could materially and adversely affect our business. Compliance with these laws and regulations is a significant factor in our business. We have incurred and expect to continue to incur capital expenditures and operating costs to comply with applicable current and future laws and regulations.

Our businesses continue to be subject to additional and changing environmental, health and safety laws and regulations, and we could incur additional costs complying with requirements that are promulgated in the future. Recently, various federal and state agencies have heightened their scrutiny of per- and polyfluoroalkyl substances (PFAS), which are manufactured chemicals used in a variety of consumer and industrial products. In August 2022, the U.S. EPA proposed to designate perfluorooctanesulfonic acid (PFOS) and perfluorooctanoic acid (PFOA), two of the most common PFAS chemicals, as hazardous substances, which could have wide-ranging impacts on companies across various industries, including ours. We are investigating whether PFAS compounds are used in our manufacturing or operating processes that occur in our various businesses. At this time, we cannot predict the outcome or the severity of the impact, if any, of future laws or regulations enacted to address PFAS.

**A cyber incident, security breach or system failure could adversely affect our business and operating results.**

The operation of our business is dependent on the secure functioning of our computer hardware and software systems. Furthermore, all our businesses require us to collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss. We also use third-party vendors to electronically process certain of our business transactions. Information systems, both ours and those of third parties, are vulnerable to security breaches by computer hackers and cyber terrorists and the negligent or intentional breach of established controls and procedures or mismanagement of confidential information by employees. We may also be impacted by attacks and data security breaches of financial institutions, merchants or third-party service providers. While we employ a defense-in-depth strategy and regularly conduct cybersecurity assessments, we cannot be certain our information security systems and protocols and those of our vendors and other third parties are sufficient to withstand a cyber-attack or other security breach.

A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For example, we may be subject to liability under various federal, state and international data protection laws. These laws are subject to change and expansion and may require additional operational changes and costs to comply.

The misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant monetary damages, regulatory enforcement actions and breach notification and mitigation expenses, such as credit monitoring, and result in reputational damage affecting relations with shareholders, customers, regulators and others. In addition to property and casualty insurance, which may cover restoration of data, certain physical damage or third-party injuries, we have cybersecurity insurance related to a breach event. However, damage and claims arising from such incidents may not be covered or may exceed the amount of any available insurance.

**The inability to attract and retain a qualified workforce could have an adverse effect on our operations.**

The success of our business is heavily dependent on the leadership of our executive officers and key employees for implementation of our strategy. In addition, all of our businesses rely on a qualified workforce, including technical employees who possess certain specialized knowledge and skills. The inability to attract and retain a skilled and stable workforce at necessary staffing levels, whether due to decreases in hiring rates, increases in employee retirements, increases in terminations, or any combination thereof, may negatively affect our ability to service our customers, manufacture products or successfully manage our business and achieve our objectives.

In 2022, we faced labor challenges within our Manufacturing segment businesses including difficulty attracting and retaining employees. In response, we offered increased compensation and hiring and retention incentives, which led to increased costs in our business. Should these challenges persist or exacerbate, our financial results could be impacted. If we are unable to maintain our desired staffing levels our ability to meet customer demand and achieve our growth targets could be negatively impacted.

## **FINANCIAL RISKS**

### **We are subject to capital market and interest rate risks.**

We rely on access to debt and equity capital markets as a source of liquidity to fund our investment initiatives, including rate base growth investments in our Electric segment and opportunities for investment, including acquisitions, in our Manufacturing and Plastics segments. Capital markets are impacted by global and domestic economic conditions, monetary policy, commodity prices, geopolitical events and other factors. If we are unable to access capital on acceptable terms and at reasonable costs, our ability to implement our business plans may be adversely affected. In addition, higher market interest rates on outstanding variable-rate, short-term indebtedness could also impact our operating results. In 2022, rising market interest rates caused the applicable rate of interest on our short-term indebtedness to increase significantly. However, the impact to our operating results was not significant due to our low level of outstanding borrowings on our short-term indebtedness. Our operating results could be impacted if we significantly increase our short-term borrowings or issue new long-term debt, and interest rates remain elevated or continue to increase.

### **A decrease in our credit ratings could increase our borrowing costs and result in additional contractual costs.**

We rely on our investment grade credit ratings to provide acceptable costs for accessing the capital markets. A downgrade of our credit ratings could result in higher borrowing costs thereby negatively impacting our operating results and limiting our ability to access capital markets, which may negatively impact our ability to implement our business plans. In addition, OTP is a party to contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below certain levels.

### **Our pension and other postretirement benefit plans are subject to investment and interest rate risks.**

The financial obligations and related costs of our pension and other postretirement benefit plans are affected by numerous factors. Assumptions related to future costs, investment returns, actuarial estimates and interest rates have a significant effect on our funding obligations and the cost recognized related to these plans. If our pension plan assets do not achieve our estimated long-term rate of return or if our other estimates prove to be inaccurate, our operating results, financial condition and liquidity may be adversely impacted. In addition, our funding requirements could be impacted by changes to the Pension Protection Act.

### **We rely on our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and pay dividends to our shareholders.**

Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the earnings, cash flows, capital requirements and general financial positions of our subsidiary companies. In addition, OTP is subject to federal and state regulations which may restrict its ability to pay dividends. Finally, we are also reliant on our subsidiary companies to maintain compliance with financial covenants under our various short- and long-term debt agreements. Our debt agreements include restrictions on the payment of cash dividends upon an event of default.

### **Changes in tax laws could materially affect our financial condition and operating results.**

Our provision for income taxes and tax obligations are impacted by various tax laws and regulations, including the availability of various tax credits, IRS tax policies such as tax normalization and, at times, the ability to carryforward net operating losses and tax credits. Changes in tax laws, regulations and interpretations could have an adverse effect on our financial condition and operating results. Tax law changes that reduce or eliminate production or investment tax credits may impact the economics of constructing certain electric generation resources, which may impact our planned investments and could adversely affect our financial condition and operating results.

### **A significant impairment of our goodwill would negatively impact our financial position and operating results.**

As of December 31, 2022, we had \$37.6 million of goodwill recorded on our consolidated balance sheet related to businesses within our Manufacturing and Plastics segments. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. The goodwill impairment test requires us to estimate the fair value of the businesses being tested. Estimating the fair value of a business unit requires significant judgments and estimates, including estimates of future operating results and cash flows, among others. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions or material differences between actual and forecasted financial performance could affect our fair value estimates and lead to a goodwill impairment charge that could adversely affect our financial condition and operating results, as well as impact compliance with financing agreement covenants.

## **ELECTRIC SEGMENT RISKS**

### **General economic and industry conditions impact our business.**

Several factors, many of which are beyond our control, may contribute to reduced demand for energy from our customers or increase the cost of providing energy to our customers. These risks include economic growth or decline in our service areas, demographic changes in our customer base and changes in customer demand or load growth due to, among other items, proliferation of distributed generation, energy efficiency initiatives and technological advancements. In addition, customer demand could be impacted by increased competition in our service territories or the loss of a service territory or franchise. Other risks include increased transmission or interconnection costs, generation curtailment and changes in the

manner in which wholesale power is purchased and sold. A decrease in revenues or an increase in expenses related to our electric operations could negatively impact our financial condition, operating results and liquidity.

**Our utility business is significantly impacted by government legislation and regulation.**

OTP is subject to federal and state legislation and comprehensive regulation by federal and state regulatory agencies, including the public utility commissions in each of the three states in which OTP operates, and by the FERC. State utility commissions regulate, among other matters, the establishment of assigned service areas, the siting and construction of major facilities, the capital structure of the utility business, and the allowed rates to charge customers for providing energy and utility service. Each state utility commission operates independent of one another; therefore, OTP is subject to and must adhere to the decisions of each independent state commission. The FERC regulates, among other matters, wholesale energy transactions, hydroelectric licensing, transmission and sale of electric energy in interstate commerce, and the interconnection of electric facilities.

Our financial condition, operating results and liquidity are significantly impacted by, and dependent upon, our ability to recover the costs associated with providing utility service and earn a return on our utility capital investments. There is no assurance that each state utility commission will judge our utility costs to have been prudently incurred or that rates will produce full recovery of such costs. In addition, changes in the federal or state regulatory framework could impair our ability to recover utility costs historically collected from our customers. In addition, prolonged inflationary cost pressures would increase the cost of constructing our utility assets and operating our utility business. Rising fuel costs in 2022 have increased the cost of providing energy to our customers. In each instance, there can be no assurance that our state regulatory commissions will authorize recovery of these rising costs.

In addition to the recovery of our utility costs, our profitability is impacted by our authorized ROE, which can be impacted by macroeconomic factors such as interest rates. There can be no assurance that each state utility commission or the FERC will authorize a rate of return which allows us to achieve our financial goals.

An adverse decision by one or more regulatory authorities concerning the level or method of determining electric utility rates; the authorized returns on equity; the authority to self-fund transmission upgrades; recoverability of fuel, purchase power and other costs; the allocation of costs between jurisdictions, approval of depreciation rates; implementation of enforceable federal reliability standards or other regulatory matters; permitted business activities, such as ownership or operation of nonelectric businesses; or any prolonged delay in rendering a decision in a rate or other proceeding could adversely impact our financial condition, operating results and liquidity.

**Our generating facilities are subject to risks that could result in early closure or the sale of our ownership interest.**

Changes in operational or economic factors, environmental regulation or risks of litigation could result in the early closure of or the sale of our interest in a generating facility. In the event of an early closure, a significant asset impairment charge could be required and we would be obligated to pay for our share of the costs of closure of the generating facility including costs associated with decommissioning, remediation, reclamation and restoration of the property, and any costs of terminating contracts associated with the generating facility, such as coal supply arrangements. In the event of a sale of our interest in a generating facility, we may not be able to negotiate the sale on favorable terms, which could result in the recognition of a loss on the sale and other potential liabilities. There can be no assurance that we would be authorized by any of our state utility commissions to recover any costs or losses associated with the early closure of or sale of our interest in a generating facility.

The loss of a major generating facility would require OTP to identify and obtain approval for other sources of generation for its customers, if available, and expose it to higher purchased power costs. In addition, OTP may not be able to obtain timely regulatory approval for new generation resources to replace closed or sold facilities.

In September 2021, our IRP filed in the three jurisdictions in which we operate outlined our plan to withdraw from our 35 percent ownership interest in Coyote Station, a jointly-owned coal-fired generation plant, by December 31, 2028. If we proceed with the withdrawal under the updated IRP which we expect to file in March 2023, we will seek to recover all costs related to the future withdrawal from Coyote Station, however, there can be no assurance that we will be granted recovery of any such costs. A full or partial denial of recovery of the costs of withdrawal could significantly impact our operating results, financial condition and liquidity.

**Federal and state environmental regulation could require us to incur substantial capital expenditures, increased operating costs or make it no longer economically viable to operate some of our facilities.**

We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements may require us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines.

Coyote Station, one of OTP's jointly-owned coal-fired power plants, is subject to assessment under the second implementation period of RHR as part of the state of North Dakota's state implementation plan, or SIP. We cannot predict with certainty the impact the SIP may have on our business until the plan has been approved or otherwise acted on by the EPA, including its potential implementation of an alternative federal implementation plan. However, significant emission control investments could be required. Alternatively, investments in emission control equipment may prove to be uneconomic and result in the early closure of or the sale of our interest in Coyote Station.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. The multiple jurisdictions that govern our electric utility business may not agree as to the appropriate resource mix, which may lead to costs incurred to comply

with one jurisdiction that are not recoverable across all jurisdictions served by the same assets. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our financial condition, operating results and liquidity, making the operation of some of our facilities no longer economically viable.

**Legislation, regulation, litigation or other actions related to climate change and greenhouse gas emissions could materially impact us.**

Current and future federal, state, regional and international regulations to address global climate change and reduce GHG emissions, including measures such as mandated levels of renewable generation, mandatory reductions in CO<sub>2</sub> emission levels, taxes on CO<sub>2</sub> emissions, or cap-and-trade regimes, could require us to incur significant costs which could negatively impact our financial condition, operating results and liquidity if such costs cannot be recovered through rates granted by rate-making authorities or through increased market prices for electricity.

In 2021, the Biden Administration introduced new targets aimed at reducing economy-wide net GHG emissions by 50 to 52 percent from 2005 levels by 2030. In addition, the Administration set a goal to reach 100 percent carbon pollution-free electricity by 2035. To achieve these targets the Administration may implement new regulations targeting GHG emissions from existing fossil fuel-fired power plants. While the precise nature and implications of any new regulations are uncertain, such regulations could impose substantial costs on and impact the operations of our utility business, which may materially impact our financial condition, operating results and liquidity.

In addition to complying with legislation and regulation, we could be subject to litigation related to climate change. In recent years, there has been an increase in litigation against electric utilities and fossil fuel producers. If OTP were subjected to such litigation, the costs of such litigation could be significant and an adverse outcome could require substantial capital expenditures, changes in operations and possible payment of penalties or damages which could affect our financial condition, operating results and liquidity if the costs are not recoverable in rates or covered by insurance.

To the extent investors view climate change, fossil fuel combustion and GHG emissions as a financial risk, our stock price or our ability to access capital markets on favorable terms and conditions could be adversely impacted.

**Violations of extensive legal and regulatory compliance requirements could have a negative impact on our business and results of operations.**

We are subject to an extensive legal and regulatory framework imposed under federal and state laws and regulatory agencies, including the FERC and the NERC. We could be subject to potential financial penalties for compliance violations. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. If a serious reliability incident were to occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance. We attempt to mitigate the risk of regulatory penalties through formal training. However, there is no guarantee our compliance program will be sufficient to ensure against violations.

In addition, energy policy initiatives at the state or federal level could increase incentives for distributed generation, or authorize municipal utility formation or acquisition of service territory, or local initiatives could introduce generation or distribution requirements that could change the current integrated utility model.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary approvals for our existing operations and that our business is conducted in accordance with applicable laws and regulatory requirements; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations or the imposition of additional regulations could have a material adverse impact on our financial condition, operating results and liquidity.

**Our transmission and generation facilities could be vulnerable to cyber and physical attack.**

OTP owns electric transmission and generation facilities subject to mandatory and enforceable standards advanced by the NERC. These bulk electric system facilities provide the framework for the electrical infrastructure of OTP's service territory and interconnected systems, the operation of which is dependent on information technology systems. Further, the information systems that operate OTP's electric system are interconnected to external networks. Parties that wish to disrupt the U.S. bulk power system or OTP's operations could view OTP's computer systems, software or networks as attractive targets for cyber-attack.

In addition, OTP's generation and transmission facilities are spread throughout a large service territory. These facilities could be subject to physical attack or vandalism that could disrupt OTP's operations or conceivably the regional or U.S. bulk power system.

OTP is subject to mandatory cybersecurity and physical security regulatory requirements. OTP implements the NERC standards for operating its transmission and generation assets and remains abreast of best practices within the business and the utility industry to protect its computers and computer-controlled systems from outside attack. We rely on industry-accepted security measures and technology to securely maintain confidential and proprietary information necessary for the operation of our systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls and disaster recovery plans designed to protect and preserve the confidentiality, integrity and availability of data and systems. We also take prudent and reasonable steps to protect the physical security of our generation and transmission facilities. However, all these measures and technology may not adequately prevent security breaches, ransomware attacks or other cyber-attacks, or enable us to recover effectively from such a breach or attack. Any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches or physical attack of our generation or transmission facilities could adversely affect our business and our financial condition, operating results and liquidity.

**Our generating facilities and transmission assets are subject to operational risks that could result in unscheduled outages and increased costs.**

The operation of electric generating facilities and transmission assets involves many risks including facility shutdowns due to equipment or process failures; aging equipment and sourcing replacement parts; labor disputes; operator error; catastrophic events such as fires, explosions and floods;

the dependence on a specific fuel source; increased costs or delayed receipt of materials due to supply chain disruptions; and the risk of performance below expected levels of output or efficiency. We could be subject to costs associated with any unexpected failure to produce or deliver power, including failures caused by a breakdown or forced outage, as well as damages to facilities or other assets.

We rely on a limited number of suppliers to provide coal and coal transportation to our facilities. A failure to perform by any of these counterparties may arise due to liquidity challenges or insolvency, operational deficiencies or other circumstances such as severe weather or natural disasters, which could impact our ability to provide service to our customers or require us to seek alternative sources for these products and services, if available, which could lead to increased costs adversely impacting our financial condition, operating results and liquidity.

**Joint ownership of coal-fired generation facilities could impact our ability to manage changing regulations and economic conditions.**

We own our coal-fired generation facilities jointly with other co-owners with varying ownership interests in such facilities. Our ability to make determinations on our IRP in order to best navigate changing environmental regulations and economic conditions may be impacted by our rights and obligations under the co-ownership agreements and related agreements, and our ability to reconcile a divergence in the interests of OTP and the co-owners of these generation facilities. Such a divergence could impair our ability to effectively manage these changing conditions to meet our strategic objectives and could adversely impact our financial condition, operating results and liquidity.

**We are subject to risks associated with energy markets.**

Our electric business is subject to the risks associated with energy markets, including market supply and changing energy prices. If we are faced with shortages in market supply, we may be unable to fulfill our contractual obligations to our retail, wholesale and other customers at previously anticipated costs. This could force us to obtain alternative energy or fuel supplies at higher costs, or suffer increased liabilities for unfulfilled contractual obligations. Any significantly higher than expected energy or fuel costs could negatively affect our financial condition, operating results and liquidity.

**MANUFACTURING SEGMENT RISKS**

**The price and availability of raw materials could adversely impact our operating results.**

The companies in our Manufacturing segment use a variety of raw materials in the products they manufacture including, among others, steel, aluminum, and polystyrene and other plastics resins. The price and availability of the raw materials used in our manufacturing processes are based on global supply and demand conditions, which can create volatile pricing and supply disruptions as conditions change. Federal trade policies, including imposed tariffs, can also impact prices for these raw materials. If we are unable to pass cost increases through to our customers or are unable to procure adequate or timely raw material inputs for use in our manufacturing processes, our financial condition, operating results and liquidity could be negatively impacted.

Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes used by our manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of our manufacturing companies as it reduces their ability to mitigate the cost associated with excess material.

**Competition from foreign and domestic manufacturers could affect the revenues and earnings of our manufacturing businesses.**

Our manufacturing businesses are subject to intense competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development personnel and facilities, and other capabilities. Our ability to compete on product performance, competitive pricing, technological innovation and customer service is critical to our ongoing success. If we are unable to compete in these and potentially other areas, our business and financial condition, operating results and liquidity could be adversely impacted.

**Economic conditions in the end markets in which our customers operate could have an adverse impact on our operating results and liquidity.**

Our manufacturing businesses derive a large amount of their revenues from customers in the following industry sectors: recreational vehicle/ powersports, lawn and garden, construction, agriculture, energy and horticulture. Factors affecting any of these industries in general could adversely affect our operating results as growth in our operating revenues is largely dependent on the growth of our customers' businesses in their respective industries. These factors include:

- seasonality of demand for our customers' products which may cause our manufacturing capacity to be underutilized for periods of time;
- our customers' failure to successfully market their products, gain or retain widespread commercial acceptance of their products or compete effectively in their industries;
- loss of market share for our customers' products which may lead our customers to reduce or discontinue purchasing our products and components and to reduce prices, thereby exerting pricing pressure on us;
- economic conditions in the markets in which our customers operate, the United States, in particular, including recessionary periods such as a global economic downturn;
- our customers' decisions to bring the production of components in-house that have traditionally been outsourced to us; and
- product design changes or manufacturing process changes that may reduce or eliminate demand for the components we supply.

We expect future sales will continue to depend on the success of our customers. If economic conditions or demand for our customers' products deteriorates, we may experience a material adverse effect on our financial condition, operating results and liquidity.

**Our business may be adversely affected if we are not able to maintain our manufacturing, engineering and technological expertise.**

The markets for our manufacturing businesses are characterized by changing technology and evolving process development. The continued success of our businesses will depend on our ability to:

- maintain technological leadership in our industry;

- implement new and expand on current robotics, automation and tooling technologies; and
- anticipate or respond to changes in manufacturing processes in a cost-effective and timely manner.

We may be unable to develop the capabilities required by our customers in the future. The emergence of new technologies, industry standards or customer requirements may render our equipment, inventory or processes obsolete or noncompetitive. We may be required to acquire new technologies and equipment to remain competitive. The acquisition and implementation of new technologies and equipment may require us to incur significant expense and capital investment, which could reduce our margins and affect our operating results. When we establish or acquire new facilities, we may not be able to maintain or develop our manufacturing, engineering and technological expertise due to a lack of trained personnel, ineffective training of new staff or technical difficulties with machinery. Failure to anticipate and adapt to customers' changing technological needs and requirements and to maintain manufacturing, engineering and technological expertise may have material adverse effects on our financial condition, operating results and liquidity.

## **PLASTICS SEGMENT RISKS**

### **Changes in PVC resin prices could negatively affect our plastics business.**

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices were rising or stable, margins and sales volumes were higher and when resin prices were falling, sales volumes and margins were lower. Changes in PVC resin prices can negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of our finished goods inventory.

Periodic shortages of PVC resin coupled with robust domestic and global demand for PVC resin led to significantly increased resin pricing throughout 2021 and the first half of 2022, which resulted in higher input costs in our Plastics segment during these years. Resin prices started to decline in the last half of 2022 and we anticipate resin prices will moderate in 2023 as these market conditions normalize. Our operating results could be impacted by the timing and degree to which resin prices stabilize.

### **Our plastics operations are highly dependent on a limited number of vendors and a limited supply of PVC resin and other materials.**

We rely on a limited number of vendors to supply the PVC resin used in our plastics business. In 2022 we sourced all of our PVC resin needs from two vendors. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region. This could increase the risk of a shortage of resin in the event of a hurricane, other extreme weather events and other natural disasters in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources were available.

Although PVC resin is the most significant raw material input in our PVC pipe manufacturing process, we also use certain other materials, such as stabilizers, gaskets, lumber, banding and others in the process of manufacturing and shipping our PVC pipe products. We generally source these materials from a limited number of suppliers and any significant supply chain constraints or disruptions related to these materials could also disrupt our ability to manufacture or ship products and could result in increased costs.

### **We compete against many other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.**

The plastic pipe industry is fragmented and competitive due to the number of producers and the fungible nature of the product. We compete not only against other plastic pipe manufacturers, but also against ductile iron, steel and concrete pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope and the principal areas of competition are a combination of price, service, warranty and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics businesses.

### **External factors beyond our control could cause fluctuations in demand for our PVC pipe products and changes in our prices and margins, which could adversely impact our operating results.**

Our PVC pipe products, sold through distributors and wholesalers, are primarily used in municipal and rural water projects, wastewater projects, storm drainage systems and reclamation systems. External factors beyond our control can cause volatility in raw material costs, demand for our products, sales prices, and deterioration in operating margins. These factors can magnify the impact of economic cycles on our business and results of operations. Examples of external factors include:

- general economic conditions including housing and construction markets which can be cyclical;
- increases in interest rates;
- severe weather and natural disasters;
- governmental regulation in the United States;
- funding shortages for municipal water and wastewater projects; and
- pandemics and other public health threats.

Our financial results in 2021 and 2022 were impacted by unique market conditions within the PVC pipe industry, including a significant increase in the price of PVC resin, and periodic shortages of certain additives and ingredients used in the manufacturing of PVC pipe which limited the manufacturing of PVC pipe. Strong demand for PVC pipe along with limited manufacturing output led to low inventories across the industry. The combination of these factors resulted in extraordinary growth in earnings and cash flows from our Plastic segment in these years. As these industry conditions begin to normalize in 2023 and beyond, we anticipate our operating results and cash flows will moderate, returning to more stable levels. Our operating results and cash flows could be impacted by the timing under which conditions normalize and the level of stabilized resin and PVC pipe prices.

## GENERAL RISK FACTORS

### Economic conditions could negatively impact our businesses.

Our businesses are affected by local, national and worldwide economic conditions, including the impact of inflation, tightening of credit in financial markets, economic recessions or other changes in economic conditions. Our businesses may be adversely affected by decreases in the general level of economic activity, such as decreases in business and consumer spending. A decline in the level of economic activity and uncertainty regarding energy and commodity prices could adversely affect our results of operations and our future growth. Inflationary pressures may lead to rising material and commodity costs and increased labor costs. Our operating results and liquidity would be adversely impacted if we were unable to recover these increased costs from our customers. Tightening of credit in financial markets could adversely affect the ability of customers to finance purchases of our goods and services, resulting in decreased orders, cancelled or deferred orders, slower payment cycles, and increased bad debt and customer bankruptcies.

### If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.

We expect much of our growth in the next few years will come from major capital investments at existing companies. To achieve the organic growth we expect, we must have access to the capital markets, be successful with capital expansion programs related to organic growth, develop new products and services, expand our markets and increase efficiencies in our businesses. Competitive and economic factors could adversely affect our ability to do this. If we are unable to achieve and sustain consistent organic growth, we will be less likely to meet our earnings growth targets, which may adversely affect the market price of our common shares.

### The economic effects of the coronavirus (COVID-19) pandemic and any other epidemic or pandemic, and measures taken to reduce and slow the spread of the disease could adversely impact our business.

The outbreak and global spread of COVID-19 has had widespread impacts on society, economies, financial markets and businesses everywhere since early 2020. The COVID-19 pandemic has impacted our business operations, including our employees, customers, construction contractors, suppliers and vendors, and some uncertainty in the nature and degree of the continued effects over time still remains. In 2022, our business was impacted by supply chain disruptions and labor shortages resulting from the pandemic, and the associated costs and inflation related thereto. The extent to which COVID-19 impacts our business going forward, if at all, remains uncertain.

We continue to monitor developments involving our workforce, customers, construction contractors, suppliers and vendors and take steps to mitigate against additional impacts, but given the unprecedented and evolving nature of these circumstances, we cannot predict the full extent of the impact that COVID-19 will have on our operating results, financial condition and liquidity.

A future widespread outbreak of an infectious disease, which affects a large percentage of the population regionally, nationally, or globally could impact our business operations, including our employees, customers, construction contractors, suppliers and vendors, and could impact our operating results, financial condition and liquidity.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

The following provides a summary of our properties which are material to our operations, by segment, as of December 31, 2022.

### ELECTRIC SEGMENT

The following reflects our wholly- or jointly-owned material electric generation facilities as of December 31, 2022:

Description	Location	Year Placed in Service	Fuel Type	Capacity - kW (Nameplate Rating)
Big Stone Plant <sup>(1)</sup>	Big Stone City, SD	1975	Subbituminous Coal	223,146
Coyote Station <sup>(2)</sup>	Beulah, ND	1981	Lignite Coal	144,900
Jamestown Combustion Turbine	Jamestown, ND	1975	Fuel Oil	48,108
Lake Preston Combustion Turbine	Lake Preston, SD	1978	Fuel Oil	24,100
Solway Combustion Turbine	Solway, MN	2003	Natural Gas/Fuel Oil	44,500
Astoria Station	Astoria, SD	2021	Natural Gas	245,000
Langdon Wind Center	Cavalier County, ND	2007	Wind	40,500
Ashtabula Wind Center	Barnes County, ND	2008	Wind	48,000
Luverne Wind Farm	Griggs and Steele Counties, ND	2009	Wind	49,500
Merricourt Wind Energy Center	McIntosh and Dickey Counties, ND	2020	Wind	150,000

<sup>(1)</sup>OTP holds a 53.9% joint ownership interest in this jointly-owned facility. The nameplate capacity indicated reflects OTP's ownership percentage.

<sup>(2)</sup>OTP holds a 35.0% joint ownership interest in this jointly-owned facility. The nameplate capacity indicated reflects OTP's ownership percentage.

On January 3, 2023, OTP purchased the Ashtabula III wind farm, a 62.4-megawatt wind farm located in eastern North Dakota.

In addition to our generation facilities, we wholly or jointly own transmission and distribution lines as of December 31, 2022 as follows:

	<i>Miles</i>
<b>Transmission</b>	
345 kV <sup>(3)</sup>	875
230 kV <sup>(4)</sup>	484
115 kV	960
Less than 115 kV	4,028
<b>Distribution</b>	
Less than 115 kV	8,413

<sup>(3)</sup> As of December 31, 2022, OTP held a 14.2% ownership interest of 242 miles, a 4.8% ownership interest of 250 miles, and a 50.0% ownership interest of 234 miles of the 345 kV transmission lines, with the remaining miles being wholly-owned.

<sup>(4)</sup> As of December 31, 2022, OTP held a 14.8% ownership interest of 70 miles of the 230 kV transmission lines, with the remaining miles being wholly-owned.

## MANUFACTURING AND PLASTICS SEGMENTS

The following reflects the material properties of our Manufacturing and Plastic segments as of December 31, 2022:

<i>Segment/Location</i>	<i>Owned/Leased</i>	<i>Facility Type/Use</i>	<i>Approximate Square Feet</i>
<b>Manufacturing Segment</b>			
Washington, IL	Leased	Office/Manufacturing/Warehouse	217,508
Detroit Lakes, MN	Owned	Office/Manufacturing/Warehouse	353,812
Lakeville, MN	Leased	Office/Manufacturing/Warehouse	413,000
Dawsonville, GA	Owned	Office/Manufacturing/Warehouse	172,000
Buford, GA	Leased	Warehouse	71,357
Clearwater, MN	Owned	Office/Manufacturing/Warehouse	203,840
Otsego, MN	Leased	Manufacturing/Warehouse	86,400
<b>Plastics Segment</b>			
Fargo, ND	Owned	Office/Manufacturing/Warehouse	122,441
Fargo, ND	Leased	Warehouse	239,580
Phoenix, AZ	Owned	Office/Manufacturing/Warehouse	86,066

We believe the facilities described above are adequate for our present business.

## ITEM 3. LEGAL PROCEEDINGS

We are the subject of various legal and regulatory proceedings in the ordinary course of our business. See [Note 13, Commitments and Contingencies](#), to the consolidated financial statements, and [Management's Discussion and Analysis of Financial Condition and Results of Operations, Regulatory Matters](#), which information is incorporated herein by reference, for discussion of certain legal, environmental and other regulatory proceedings to which we are a party.

## ITEM 3A. INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Set forth below is a summary of the principal occupations and business experience during the past five years of the executive officers as defined by rules of the SEC. Each of the executive officers has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly-owned subsidiary, Otter Tail Power Company.

<i>Name and Age</i>	<i>Date Elected to Office</i>	<i>Current Position</i>
Charles S. MacFarlane (58)	04/13/15	President and Chief Executive Officer
Kevin G. Moug (63)	04/09/01	Chief Financial Officer and Senior Vice President
Timothy J. Rogelstad (56)	04/14/14	Senior Vice President, Electric Platform
John S. Abbott (64)	02/11/15	Senior Vice President, Manufacturing Platform
Jennifer O. Smestad (52)	01/01/18	Vice President, General Counsel and Corporate Secretary

**Chuck MacFarlane** has served as the Company's President and Chief Executive Officer and as a member of the Company's Board of Directors since April 13, 2015.

**Kevin Moug** has served as Chief Financial Officer and Senior Vice President of the Company since April 9, 2001.

**Timothy Rogelstad** has served as President of OTP and Senior Vice President, Electric Platform of the Company since April 14, 2014.

**John Abbott** has served as Senior Vice President, Manufacturing Platform, since February 5, 2015.

**Jennifer Smestad** has served as Vice President, General Counsel and Corporate Secretary of the Company, since January 1, 2018. Ms. Smestad has also served as General Counsel for OTP since March 1, 2013.

The term of office for each of the executive officers is one year and any executive officer elected may be removed by the vote of the board of directors at any time during the term. There are no family relationships between any of the executive officers or directors.

#### **ITEM 4. MINE SAFETY DISCLOSURES**

Not Applicable.

## PART II

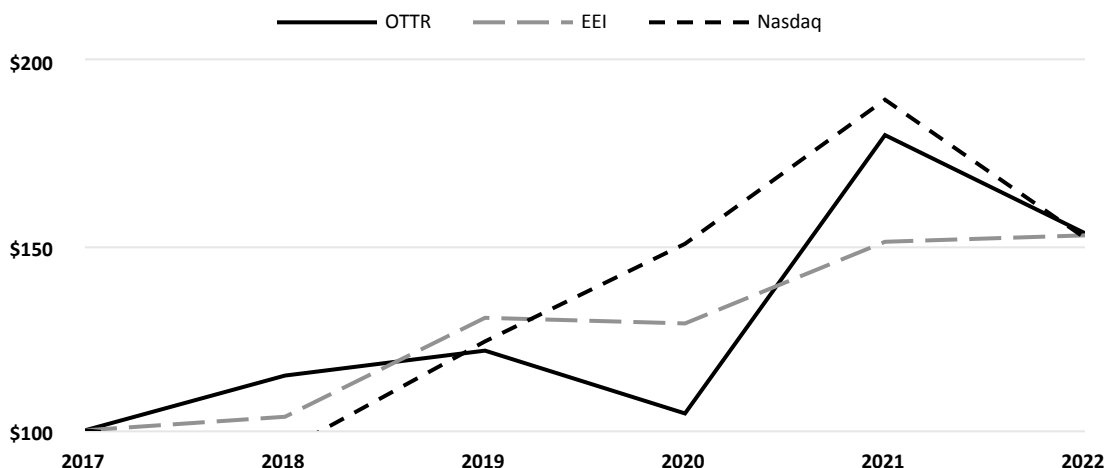
### ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the Nasdaq Global Select Market under the Nasdaq symbol "OTTR". As of December 31, 2022, there were 11,748 holders of record of our common stock.

We do not have a publicly announced stock repurchase program and we did not repurchase any equity securities during the year ended December 31, 2022.

#### PERFORMANCE GRAPH COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

This graph compares the cumulative total shareholder return on our common shares for the last five years with the cumulative return of the Nasdaq Stock Market Index and the Edison Electric Institute (EEI) Index over the same period (assuming the investment of \$100 in each vehicle on December 31, 2017, and reinvestment of all dividends).



		2017		2018		2019		2020		2021		2022
<b>OTTR</b>	\$	100.00	\$	114.80	\$	121.54	\$	104.56	\$	179.79	\$	<b>153.27</b>
<b>EEI</b>	\$	100.00	\$	103.67	\$	130.41	\$	128.89	\$	150.96	\$	<b>152.70</b>
<b>Nasdaq</b>	\$	100.00	\$	94.56	\$	124.03	\$	150.41	\$	189.36	\$	<b>152.00</b>

### ITEM 6. [RESERVED]

### ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis of our financial condition and results of operations together with our financial statements and the related notes appearing under [Item 8](#) of this Form 10-K.

#### OVERVIEW

Otter Tail Corporation and its subsidiaries form a diverse group of businesses with operations classified into three segments: Electric, Manufacturing and Plastics. Our Electric business is a vertically integrated, regulated utility with generation, transmission and distribution facilities to serve our customers in western Minnesota, eastern North Dakota and northeastern South Dakota. Our Manufacturing segment provides metal fabrication for custom machine parts and metal components, and manufactures extruded and thermoformed plastic products. Our Plastics segment manufactures PVC pipe for use in, among other applications, municipal and rural water, wastewater and water reclamation projects.

Our strategy includes investing in rate base growth opportunities in our Electric segment and capitalizing on organic growth opportunities in our Manufacturing and Plastics segments. Investments in our Electric segment are expected to produce increased earnings and cash flows, lower our overall risk, create a more predictable earnings stream, improve our credit quality and preserve our ability to fund our dividend. Our Electric segment is complemented by our Manufacturing and Plastics segment businesses, which we expect to contribute to earnings growth by capitalizing

on market expansion opportunities and increasing utilization of existing capacities, along with planned investments to create additional capacity and increased efficiencies. Collectively, our mix of businesses is expected to contribute to the achievement of our targeted annual growth in earnings per share of five to seven percent over the next several years, using 2024 as the base for measurement.

## **2022 FINANCIAL RESULTS**

In 2022, our diversified business model generated record financial results, producing net income of \$284.2 million, or \$6.78 per diluted share, an increase of 61% from \$176.8 million, or \$4.23 per diluted share, in 2021. All three of our operating segments produced double digit earnings growth in 2022 compared to the prior year, led by our Plastics segment, which capitalized on the continuation of unique market conditions to produce extraordinary financial results. In 2022, we paid an annual dividend of \$1.65 per share, or \$68.8 million, completing our 84th consecutive year of dividend payments to our shareholders.

Our Electric segment produced earnings growth of 10% in 2022, driven by increased customer demand from commercial and industrial customers, including the addition of a new large commercial customer in North Dakota, and the impacts of favorable weather. We continued the construction of rate base investments, including our Hoot Lake Solar project, which we anticipate will be in commercial operation by the end of 2023. Our utility also accomplished all of its key regulatory objectives for the year, including completing a general rate case in Minnesota, with final rates becoming effective on July 1, 2022, and securing all necessary approvals to acquire the Ashtabula III wind farm, which was finalized and purchased on January 3, 2023.

Our Manufacturing segment produced earnings growth in 2022 of 22%, as strong end market demand across most markets we serve led to increased sales volumes. Pricing increases and favorable cost absorption offset increased labor, material, and overhead costs, which resulted in consistent gross profit levels. Our Manufacturing segment was also impacted in 2022 by steel price volatility, as further discussed below.

Our Plastics segment produced earnings of \$195.4 million in 2022, compared to \$97.8 million in 2021. The unprecedented level of earnings in 2022 resulted from extraordinary industry supply and demand dynamics which emerged in 2021 and continued into 2022. As further described below, increases in the price of resin, the primary raw material used in the manufacturing of PVC pipe, coupled with robust end market demand for PVC pipe led to a rapid escalation in PVC pipe prices and gross margins in 2021 and into 2022. Resin prices declined from peak levels in the second half of the year, and pipe distributors and contractors reduced purchase volumes and inventory levels in response to changing market conditions. Despite softening demand in the second half of the year, strong pipe sales prices and profit margins resulted in earnings growth of 100% in 2022.

Our earnings mix in 2022 was 28% from our Electric segment and 72% from the combination of our Manufacturing and Plastics segments net of unallocated corporate costs. Electric segment earnings as a percentage of our total earnings were less than our long-term target of 65% due to the unique market conditions that occurred in our Plastics segment. We expect our earnings mix to return to our targeted mix of 65% from the Electric segment and 35% from the Manufacturing and Plastics segments in 2024.

## **STEEL PRICING**

Volatility in the price of steel, a key material input to our Manufacturing segment, significantly impacted our operating results in 2022. Steel prices increased rapidly throughout 2021, peaking in the fourth quarter at historically high levels. Steel prices, which were highly volatile in 2022, began to steadily decline at the end of the second quarter and returned to near historical levels by the end of the year. The increase in steel prices led to increased sale prices for our products at BTM, our metal fabrication business within our Manufacturing segment, as we passed along material cost increases to our customers. Scrap metal prices, which typically follow steel prices, also increased throughout 2021 and remained elevated in the first half of 2022, but declined sharply throughout the second half of the year, negatively impacting our 2022 financial results.

## **PVC PIPE SUPPLY AND DEMAND CONDITIONS**

PVC resin is the primary material input of the PVC pipe manufactured by our Plastics segment businesses. Resin supply disruptions throughout 2021, along with robust domestic and global demand for PVC resin, led to significantly increased resin prices. Supply disruptions for resin and other additives and ingredients used in the manufacturing process also resulted in reduced manufacturing of PVC pipe and low pipe inventories across the industry. This combination of disrupted raw material supply and the resulting low PVC pipe inventories, along with robust demand for PVC pipe, led to rapidly increasing sale prices for PVC pipe throughout 2021 and 2022. The increase in sale prices outpaced the increase in PVC resin costs and led to expanding gross profit margins which positively impacted our 2022 financial results. However, beginning in the third quarter of 2022, demand for PVC pipe began to decline as PVC pipe distributors and contractors reduced purchase volumes and inventory levels in response to changing market conditions.

The unique market dynamics experienced by our Plastics segment businesses in 2021 and 2022 resulted in a significant increase in earnings compared to prior periods. We currently expect earnings of our Plastics segment to decrease in 2023, but to remain elevated relative to historical levels. We currently expect segment earnings to normalize in 2024, as industry supply and demand conditions normalize throughout 2023.

The marketplace dynamics impacting both our Manufacturing and Plastics segments are fluid and subject to change which may impact our operating results prospectively.

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## **FINANCIAL AND OTHER METRICS**

**Heating Degree Days (HDDs)** is a measure of how much (in degrees), and for how long (in days), the outside air temperature was below a certain normalized level. Normal weather conditions are defined as the 20-year average of actual historical weather conditions. This measure is commonly used in calculations relating to the energy consumption required to heat buildings.

**Cooling Degree Days (CDDs)** is a measure of how much (in degrees), and for how long (in days), the outside air temperature was above a certain normalized level. This measure is commonly used in calculations relating to the energy consumption required to cool buildings.

OTP generally bases its forecasted kwh sales and rates on expected consumption under a normal level of HDDs and CDDs over a given period of time in its service territory. Increased or decreased levels of consumption for certain customer classifications are attributed to deviation from the norms and are a significant factor influencing consumption of electricity across our service territory. We present HDDs and CDDs to provide an indication of the impact of weather on kwh sales, revenues and earnings relative to forecast and on period-to-period results.

**Utility Rate Base** is the value of property on which a public utility is permitted to earn a specified rate of return in accordance with rules set by a regulatory agency. In general, rate base consists of the value of property used by the utility in providing service. Rate base can also include cash, working capital, materials and supplies, deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits dependent on the method that is used in the calculation, which can vary from jurisdiction to jurisdiction. We present actual and forecasted levels of utility rate base to provide an indication of expected investments on which we expect to earn future returns.

## RESULTS OF OPERATIONS

For a comparison of fiscal year 2021 to 2020, see Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our report on [Form 10-K](#) for the fiscal year ended December 31, 2021, filed with the SEC on February 16, 2022.

Provided below is a summary and discussion of our operating results on a consolidated basis followed by a discussion of the operating results of each of our segments, Electric, Manufacturing and Plastics. In addition to the segment results, we provide an overview of our Corporate costs. Our Corporate costs do not constitute a reportable segment but rather consist of unallocated general corporate expenses, such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of segment performance. Corporate costs are added to operating segment totals to reconcile to totals on our consolidated statements of income.

### CONSOLIDATED RESULTS

The following table summarizes our consolidated results of operations for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	2022	2021	\$ change	% change
Operating Revenues	\$ 1,460,209	\$ 1,196,844	\$ 263,365	22.0 %
Operating Expenses	1,069,770	947,136	122,634	12.9
<b>Operating Income</b>	<b>390,439</b>	<b>249,708</b>	<b>140,731</b>	<b>56.4</b>
Interest Charges	36,016	37,771	(1,755)	(4.6)
Nonservice Cost Components of Postretirement Benefits	(1,075)	2,016	(3,091)	(153.3)
Other Income	2,037	2,900	(863)	(29.8)
<b>Income Before Income Taxes</b>	<b>357,535</b>	<b>212,821</b>	<b>144,714</b>	<b>68.0</b>
Income Tax Expense	73,351	36,052	37,299	103.5
<b>Net Income</b>	<b>\$ 284,184</b>	<b>\$ 176,769</b>	<b>\$ 107,415</b>	<b>60.8 %</b>

**Operating Revenues** increased \$263.4 million on a consolidated basis in 2022. Each operating segment contributed to the overall growth. Electric segment operating revenues increased 14% primarily due to increased fuel recovery revenues and higher sales volumes. Manufacturing segment operating revenues increased 18% mainly as a result of higher sales volumes and increased pricing to pass through material input costs. Plastics segment operating revenues increased 35% due to an increase in the price per pound of PVC pipe sold, partially offset by decreased sales volumes. See our segment disclosures below for additional discussion of items impacting operating revenues.

**Operating Expenses** increased \$122.6 million in 2022. Electric segment operating expenses increased 17% primarily due to increased purchased power costs resulting from increased purchase volumes and higher operating and maintenance expenses. Operating expenses in our Manufacturing segment increased 18%, driven by increased cost of products sold, which resulted from higher material input costs and increased sales volumes. Operating expenses in our Plastics segment were consistent year over year due to lower sales volumes which were offset by higher costs of products sold from higher resin costs and increased operating costs. See our segment disclosures below for additional discussion of items impacting operating expenses.

**Interest Charges** decreased \$1.8 million in 2022 primarily due to a decrease in our average short-term borrowings, partially offset by increased interest rates on our short-term borrowings and a net increase in our long-term debt of \$60.0 million. The increase in our long-term debt was largely used to finance rate base investments in our Electric segment.

**Nonservice Cost Components of Postretirement Benefits** decreased \$3.1 million in 2022 primarily due to the amortization of actuarial gains resulting from the increase in the discount rates used to measure our pension benefit and other postretirement benefit liabilities as of December 31, 2021.

**Other Income** decreased \$0.9 million in 2022 primarily due to investment losses on our corporate-owned life insurance policies and the investments of our captive insurance entity.

**Income Tax Expense** increased \$37.3 million in 2022 primarily due to an increase in income before income taxes. Our effective tax rate was 20.5% in 2022 and 16.9% in 2021. See Note 12 to our consolidated financial statements included in the report on Form 10-K for additional information regarding factors impacting our effective tax rate.

## ELECTRIC SEGMENT RESULTS

The following table summarizes the operating results of our Electric segment for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>		<b>2022</b>	<b>2021</b>	<b>\$ change</b>	<b>% change</b>
Retail Sales Revenue	\$	<b>470,300</b>	\$ 405,484	\$ 64,816	16.0 %
Transmission Services Revenues		<b>52,213</b>	48,835	3,378	6.9
Wholesale Revenues		<b>18,539</b>	17,936	603	3.4
Other Electric Revenues		<b>8,647</b>	8,066	581	7.2
Total Operating Revenue		<b>549,699</b>	480,321	69,378	14.4
Production Fuel		<b>65,110</b>	59,327	5,783	9.7
Purchased Power		<b>100,281</b>	65,409	34,872	53.3
Operating and Maintenance Expenses		<b>181,378</b>	159,669	21,709	13.6
Depreciation and Amortization		<b>72,050</b>	71,343	707	1.0
Property Taxes		<b>17,742</b>	17,609	133	0.8
Operating Income	\$	<b>113,138</b>	\$ 106,964	\$ 6,174	5.8 %

<b>Electric kwh Sales (in thousands)</b>					
Retail kwh Sales		<b>5,592,368</b>	4,789,879	802,489	16.8 %
Wholesale kwh Sales		<b>267,184</b>	420,044	(152,860)	(36.4)
<b>Heating Degree Days</b>		<b>7,122</b>	5,794	1,328	22.9
<b>Cooling Degree Days</b>		<b>531</b>	704	(173)	(24.6)

Our Electric segment operating results are impacted by fluctuations in weather conditions and the resulting demand for electricity for heating and cooling. The following table presents heating and cooling degree days as a percent of normal for the years ended December 31, 2022 and 2021:

	<b>2022</b>	<b>2021</b>
Heating Degree Days	<b>112.5 %</b>	91.3 %
Cooling Degree Days	<b>113.5 %</b>	151.7 %

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kwh sales under actual weather conditions and expected retail kwh sales under normal weather conditions for the years ended December 31, 2022 and 2021, and between years:

	<b>2022 vs Normal</b>	<b>2022 vs 2021</b>	<b>2021 vs Normal</b>
Effect on Diluted Earnings Per Share	\$ 0.11	\$ 0.10	\$ 0.01

**Retail Revenues** increased \$64.8 million primarily due to the following:

- A \$42.5 million increase in fuel recovery revenues primarily due to increased purchased power volumes and pricing to recover production fuel costs, as described below.
- A \$12.8 million increase in retail revenues from increased sales volumes from commercial and industrial customers, including the impact of a new commercial customer load in North Dakota.
- A \$5.4 million increase in revenues from the favorable impact of weather compared to last year.
- A \$4.1 million increase in interim rate revenue due to the finalization of the interim rate refund, as approved by the MPUC in the second quarter of 2022.

Retail revenues also benefited from increased transmission, renewable and phase-in rider revenue in 2022. These increases were partially offset by a decrease in CIP revenue as a result of decreased CIP spending and related cost recovery.

**Transmission Services Revenues** increased \$3.4 million primarily due to increased recovery of higher transmission costs and increased transmission investments along with increased transmission volumes and formula rate adjustments.

**Production Fuel** costs increased \$5.8 million due to a 22% increase in fuel cost per kwh, which was partially offset by a decrease in kwhs generated from our fuel-burning plants due to an outage at Coyote Station in 2022, and the retirement of Hoot Lake Plant in May 2021.

**Purchased Power** costs to serve retail customers increased \$34.9 million due to a 54% increase in the volume of purchased power, resulting from outages at both Coyote Station and Big Stone Plant, the retirement of Hoot Lake Plant and increased customer demand.

**Operating and Maintenance Expense** increased \$21.7 million primarily due to:

- A \$6.7 million increase in employee compensation and benefit costs, including discretionary incentive and retirement benefit compensation based on current year financial results.
- A \$3.7 million increase in transmission tariff expenses.
- A \$3.3 million increase in maintenance and other costs due to our plant outages at Coyote Station and Big Stone Plant during the year.
- A \$1.4 million increase in travel costs driven by higher fuel costs for our vehicle fleet and increased travel activities.
- Other additional costs including additional maintenance costs, increases in information technology expenses, increases in insurance costs and various other expenses.

These expense increases were partially offset by, among other items, a \$2.1 million reduction in CIP expenses compared to the previous year.

## MANUFACTURING SEGMENT RESULTS

The following table summarizes operating results of our Manufacturing segment for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>	<b>\$ change</b>	<b>% change</b>
Operating Revenues	\$ 397,983	\$ 336,294	\$ 61,689	18.3 %
Cost of Products Sold	315,375	259,581	55,794	21.5
Other Operating Expenses	37,341	37,163	178	0.5
Depreciation and Amortization	16,202	15,436	766	5.0
Operating Income	\$ 29,065	\$ 24,114	\$ 4,951	20.5 %

**Operating Revenues** increased \$61.7 million primarily due to the following:

- At BT.D, operating revenues increased \$52.8 million due to a combination of higher sales volumes and increased pricing. Sales volumes increased 12% compared to the previous year due to strong end market demand. Material costs, which are passed through to customers, increased 8%, as annual steel prices increased from the previous year. Steel prices increased drastically in 2021, peaking in the fourth quarter, and remained elevated compared to historical levels throughout the first half of 2022. Increases in sales volumes and prices were partially offset by a \$2.5 million decrease in scrap revenues due to a decrease in both scrap metal prices and scrap volumes.
- At T.O. Plastics, revenues increased \$8.8 million due to a combination of increased sales prices and higher sales volumes. Sales prices increased 16% and sales volumes increased 7% due to strong customer demand primarily in horticulture product sales.

**Cost of Products Sold** increased \$55.8 million due to the following:

- Cost of products sold at BT.D increased \$50.2 million primarily due to higher sales volumes and increased material costs, as discussed above. Cost of products sold also increased due to higher labor and overhead costs, partially offset by lower freight costs.
- Cost of products sold at T.O. Plastics increased \$5.6 million primarily due to higher sales volumes, primarily in horticulture product sales, partially offset by favorable cost absorption.

## PLASTICS SEGMENT RESULTS

The following table summarizes operating results for our Plastics segment for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>	<b>\$ change</b>	<b>% change</b>
Operating Revenues	\$ 512,527	\$ 380,229	\$ 132,298	34.8 %
Cost of Products Sold	227,569	228,789	(1,220)	(0.5)
Other Operating Expenses	16,175	14,326	1,849	12.9
Depreciation and Amortization	4,205	4,354	(149)	(3.4)
Operating Income	\$ 264,578	\$ 132,760	\$ 131,818	99.3 %

**Operating Revenues** increased \$132.3 million primarily due to a 66% increase in the price per pound of PVC pipe sold, as sales prices remained high and continued to increase in 2022, due to a continuation of extraordinary market conditions first experienced in the previous year. Sales volumes decreased 19% due to raw material constraints in the first half of 2022 and softening customer demand during the second half of 2022 driven by contractors delaying projects due to supply chain issues, softening housing market outlook, and customers reducing purchases of PVC pipe in order to use up existing on hand inventory.

**Cost of Products Sold** decreased \$1.2 million primarily due to a 19% decrease in sales volumes, partially offset by a 22% increase in the cost per pound of PVC pipe sold, largely due to higher resin costs.

**Other Operating Expenses** increased \$1.8 million due to increases in various cost categories including compensation costs and sales commissions.

## CORPORATE COSTS

The following table summarizes Corporate results of operations for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>		2022	2021	\$ change	% change
Other Operating Expenses	\$	16,202	\$ 13,905	\$ 2,297	16.5 %
Depreciation and Amortization		140	225	(85)	(37.8)
Operating Loss	\$	16,342	\$ 14,130	\$ 2,212	15.7 %

**Other Operating Expenses** increased \$2.3 million primarily due to increased external service costs during the year, as well as increased employee compensation and other costs.

## REGULATORY MATTERS

The following provides a summary of OTP's current general rates and a summary of recent rate case filings and rate rider filings that have or are expected to have a material impact on our operating results, financial position, or cash flows.

### GENERAL RATES

The following includes a summary of electric base rates as determined in OTP's most recent general rate case in each state:

<i>Jurisdiction</i>	<i>Implementation Date</i>	<i>Revenue Requirement (in millions)</i>	<i>Return on Rate Base</i>	<i>Allowed Return on Equity</i>	<i>Equity Ratio</i>
Minnesota	07/01/22	\$ 209.0	7.18 %	9.48 %	52.50 %
North Dakota	02/01/19	153.1	7.64	9.77	52.50
South Dakota <sup>(1)</sup>	08/01/19	35.5	7.09	8.75	52.92

*(1) Includes an earnings sharing mechanism to share with South Dakota customers any weather-normalized earnings above the authorized ROE of 8.75%. The mechanism requires 50% of any weather-normalized revenue creating annual earnings in excess of the authorized ROE up to a maximum of 9.50% be returned to customers and 100% returns of revenue creating annual earnings above 9.50%.*

**Minnesota Rate Case:** On November 2, 2020, OTP filed an initial request with the MPUC for an increase in revenue recoverable through base rates in Minnesota, and on December 3, 2020, the MPUC approved an interim annual rate increase of \$6.9 million, or 3.2%, effective January 1, 2021.

On February 1, 2022, the MPUC issued its written order on final rates. The key provisions of the order included a revenue requirement of \$209.0 million, based on a return on rate base of 7.18% and an allowed ROE of 9.48% on an equity ratio of 52.5%. The order also authorized recovery of our remaining Hoot Lake Plant net asset over a five-year period and approved the requested decoupling mechanism for most residential and commercial customer rate groups with a cap of 4% of annual base revenues.

On May 12, 2022, OTP's final rate case compliance filing was approved by the MPUC. The filing included final revenue calculations, rate design, and resulting tariff revisions, along with a determination of the interim rate refund, which resulted in an increase in revenues in 2022 of \$4.1 million. Final rates took effect on July 1, 2022, and interim rate refunds of \$15.3 million were completed in the third quarter of 2022.

## RATE RIDERS

The following table includes a summary of pending and recently concluded rate rider proceedings:

Recovery Mechanism	Jurisdiction	Status	Filing Date	Amount (in millions)	Effective Date	Notes
RRR - 2022	MN	Requested	11/01/22	\$17.5	07/01/23	Includes the recovery of the Hoot Lake Solar Project, the purchase of the Ashtabula III wind farm, and true up PTCs in base rates to actual PTCs generated at the Merricourt wind farm.
CIP - 2022	MN	Approved	04/01/22	10.8	10/01/22	Includes recovery of energy conservation improvement costs as well as a demand side management financial incentive.
CIP - 2021	MN	Approved	04/01/21	9.4	12/01/21	Includes recovery of energy conservation improvement costs as well as a demand side management financial incentive.
TCR - 2021	MN	Approved	11/23/21	7.2	08/01/22	Includes recovery of two new transmission projects.
RRR - 2021	MN	Approved	12/06/21	7.0	08/01/22	Includes return on Hoot Lake Solar construction costs and costs associated with the acquisition of the Ashtabula III wind farm.
RRR - 2023	ND	Requested	12/30/22	17.0	04/01/23	Includes recovery of Ashtabula III investment, along with other proposals, see additional information below.
RRR - 2021	ND	Approved	03/07/21	11.8	04/01/21	Includes recovery of Merricourt investment and operating costs.
RRR - 2022	ND	Approved	01/05/22	7.8	04/01/22	Includes Merricourt recovery, the proposed purchase of Ashtabula III, and credits related to deferred taxes and PTCs.
TCR - 2022	ND	Approved	09/15/22	7.5	01/01/23	Includes recovery of three new transmission projects, one transmission rebuild project, and six transmission projects related to extending the useful life of transmission assets.
TCR - 2021	ND	Approved	09/15/21	6.1	01/01/22	Includes recovery of three new transmission projects/programs.
TCR - 2020	ND	Approved	08/31/20	5.6	01/01/21	Includes recovery of eight new transmission projects.
GCR - 2021	ND	Approved	03/01/21	5.2	07/01/21	Includes recovery of Astoria Station, net of anticipated savings associated with the retirement of Hoot Lake Plant.
GCR - 2022	ND	Approved	03/01/22	3.3	07/01/22	Annual update to generation cost recovery rider.
AMDT - 2022	ND	Approved	07/08/22	3.1	01/01/23	Includes recovery of the advanced metering infrastructure, outage management system, and demand response projects.
PIR - 2022	SD	Approved	06/01/22	3.0	09/01/22	Includes recovery of the Ashtabula III wind farm purchase, Merricourt, Astoria Station, and the Advanced Grid Infrastructure project, as well as load growth credits.
TCR - 2023	SD	Requested	11/01/22	3.0	03/01/23	Includes the recovery of one new and four previously approved transmission projects.
TCR - 2022	SD	Approved	10/29/21	2.2	03/01/22	Annual update to TCR rider.
TCR - 2021	SD	Approved	10/30/20	2.2	03/01/21	Includes recovery of two new transmission projects.

**Renewable Resource Rider (RRR) and Energy Adjustment Rider (EAR):** On December 30, 2022, OTP filed an update to its North Dakota RRR. The update included, among other items, a request to modify load allocation factors in North Dakota given the large new load added in the state in 2022. If approved, the load allocation factor change would produce an additional \$4.4 million of rider recovery over a 12 month period. On January 23, 2023, OTP filed an update to its North Dakota EAR proposing to refund MISO planning resource auction revenues to North Dakota customers if the NDPSC approves the load allocation factor modification as filed in the RRR docket. If approved, OTP would refund approximately \$4.2 million of planning resource auction revenues to North Dakota customers.

## MISO PLANNING RESOURCE AUCTION

OTP offered 88-megawatts of excess capacity into the annual MISO planning resource auction for the period June 2022 through May 2023. As a result of a capacity shortage in the MISO region, capacity prices cleared the auction at maximum pricing. As a result, the 88-megawatts of auctioned capacity will generate approximately \$9.3 million of net capacity auction revenues over the twelve month period ending in May 2023. We anticipate the Minnesota allocated portion of net capacity auction revenues will be returned to customers through the FCA mechanism in the state, and the majority of the net capacity auction revenues allocated to our other jurisdictions will be used to mitigate customer rate increases or returned to customers through various mechanisms.

## INTEGRATED RESOURCE PLAN

The MPUC recently approved a change to the procedural schedule for our 2022 IRP, which was originally filed in September 2021, and we plan to file an updated IRP in March 2023. In conjunction with the updated IRP, our preferred plan could change based on the results of the updated resource modeling we perform, incorporating recent changes affecting the energy industry and the passing of the IRA, as well as other changes. A change to our preferred plan could ultimately impact the nature, timing and amount of future capital investments, as well as the potential for OTP's withdrawal from Coyote Station, and could have a material impact on our operating results, financial position or cash flows.

## LIQUIDITY

### LIQUIDITY OVERVIEW

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets, and borrowing ability because of investment-grade credit ratings, when taken together, provide us ample liquidity to conduct business operations and fund our capital expenditure program. Our liquidity, including our operating cash flows and access to capital markets, can be impacted by macroeconomic factors outside of our control. In addition, our liquidity could be impacted by non-compliance with covenants under our various debt instruments. As of December 31, 2022, we were in compliance with all debt covenants (see the Financial Covenant section under Capital Resources below).

The following table presents the status of our lines of credit as of December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>Line Limit</i>	<i>2022</i>			<i>2021</i>	
		<i>Amount Outstanding</i>	<i>Letters of Credit</i>	<i>Amount Available</i>	<i>Amount Available</i>	
Otter Tail Corporation Credit Agreement	\$ 170,000	\$ —	\$ —	\$ 170,000	\$ 147,363	
OTP Credit Agreement	170,000	8,204	9,573	152,223	88,315	
Total	\$ 340,000	\$ 8,204	\$ 9,573	\$ 322,223	\$ 235,678	

We have an internal risk tolerance metric to maintain a minimum of \$50 million of liquidity under the OTC Credit Agreement. Should additional liquidity be needed, this agreement includes an accordion feature allowing us to increase the amount available to \$290 million, subject to certain terms and conditions. The OTP Credit Agreement also includes an accordion feature allowing OTP to increase that facility to \$250 million, subject to certain terms and conditions.

### CASH FLOWS

The following is a discussion of our cash flows for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>2022</i>	<i>2021</i>
Net Cash Provided by Operating Activities	\$ 389,309	\$ 231,243

**Net Cash Provided by Operating Activities** increased \$158.1 million primarily due to a \$107.4 million increase in net income and a lower level of working capital needs compared to the previous year. Our working capital decrease was primarily the result of a \$30.6 million decrease in accounts receivable and a \$5.3 million decrease in inventories, which exceeded the decrease in accounts payable and accrued and other liabilities. The decrease in accounts receivable was primarily due to decreased sales prices in our Manufacturing segment in the second half of the year, as steel prices declined from historically high levels in 2021, and decreased sales volumes in our Plastics segment in the second half of the year, as customer demand softened. The decrease in inventories was largely the result of decreased material costs within our Manufacturing segment, due to the decrease in steel prices. The decrease in accounts payable was largely due to the decreased material costs in our Manufacturing segment and decreased sales volumes in our Plastics segment in the second half of the year.

Unique market dynamics experienced by our Plastics segment businesses in 2022 and 2021 resulted in a significant increase in our overall cash from operations compared to prior periods, and we do not expect cash from operations at these levels to continue in future years.

<i>(in thousands)</i>	<i>2022</i>	<i>2021</i>
Net Cash Used in Investing Activities	\$ 175,071	\$ 171,510

**Net Cash Used in Investment Activities** increased \$3.6 million due to a \$7.8 million increase in capital investments in our Electric segment, combined with a decrease in proceeds received from the sale of debt and equity securities at our captive insurance entity, largely offset by a decrease in capital investments in our Manufacturing and Plastics segments.

<i>(in thousands)</i>	<i>2022</i>	<i>2021</i>
Net Cash Used in Financing Activities	\$ 96,779	\$ 59,359

**Net Cash Used in Financing Activities** increased \$37.4 million primarily due to repayments of short-term borrowings, partially offset by increases in long-term debt. Our financing activities in 2022 included the issuance of \$90.0 million of long-term debt and the maturity and repayment of \$30.0 million of debt at OTP, net repayments of short-term borrowings of \$83.0 million, which were repaid with available cash resulting from increased cash from operations, and dividend payments of \$68.8 million. In 2021, \$140.0 million of long-term debt was issued and used to repay \$140.0 million of maturing long-term debt at OTP, we incurred \$10.1 million of net short-term borrowings on our lines of credit, and paid \$64.9 million in dividends.

## CAPITAL REQUIREMENTS

### CAPITAL EXPENDITURES

We have a capital expenditure program for expanding, upgrading and improving our facilities and operating equipment. Typical uses of cash for capital expenditures are investments in electric generation facilities and environmental upgrades, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, and computer hardware and information systems. Our capital expenditure program is subject to review and is revised in light of changes in demands for energy, technology, environmental laws, regulatory changes, business expansion opportunities, the costs of labor, materials and equipment and our financial condition.

The following provides a summary of capital expenditures for the years ended December 31, 2022 and 2021 for our Electric segment and non-electric businesses and anticipated capital expenditures for the five year period 2023 through 2027:

<i>(in millions)</i>	2021	2022	2023	2024	2025	2026	2027	Total
<b>Electric Segment:</b>								
Renewables and Natural Gas Generation			\$ 88	\$ 119	\$ 88	\$ 79	\$ 10	\$ 384
Technology and Infrastructure			33	30	6	5	1	75
Distribution Plant Replacements			33	37	38	38	43	189
Transmission (includes replacements)			34	36	46	87	78	281
Other			26	25	30	25	22	128
<b>Total Electric Segment</b>	\$ 140	\$ 148	\$ 214	\$ 247	\$ 208	\$ 234	\$ 154	\$ 1,057
<b>Manufacturing and Plastics Segments</b>	32	23	48	53	29	25	24	179
<b>Total Capital Expenditures</b>	\$ 172	\$ 171	\$ 262	\$ 300	\$ 237	\$ 259	\$ 178	\$ 1,236
<b>Total Electric Utility Average Rate Base</b>	\$ 1,575	\$ 1,624	\$ 1,750	\$ 1,850	\$ 1,990	\$ 2,110	\$ 2,210	
Rate Base Growth	13.7 %	3.1 %	7.8 %	5.7 %	7.6 %	6.0 %	4.7 %	

### CONTRACTUAL OBLIGATIONS

The following table summarizes our contractual obligations at December 31, 2022 and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

<i>(in millions)</i>	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Debt Obligations	\$ 835	\$ 8	\$ —	\$ 122	\$ 705
Interest on Debt Obligations	637	35	70	67	465
Coal Contracts	527	24	49	52	402
Capacity and Energy Requirements	5	—	1	—	4
Postretirement Benefit Obligations	86	5	12	13	56
Other Purchase Obligations (including land easements)	55	14	4	4	33
Operating Lease Obligations	21	6	10	4	1
<b>Total Contractual Cash Obligations</b>	\$ 2,166	\$ 92	\$ 146	\$ 262	\$ 1,666

Coal contract obligations are based on estimated coal consumption and costs for the delivery of coal to Coyote Station from Coyote Creek Mining Company (CCMC) under the LSA that ends in 2040. Postretirement benefit obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan (ESSRP), but do not include amounts to fund our noncontributory funded pension plan, as we are not currently required to make a contribution to that plan.

### COMMON STOCK DIVIDENDS

We paid dividends to our shareholders totaling \$68.8 million, or \$1.65 per share, in 2022. The determination of the amount of future cash dividends to be paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by OTC subsidiaries. See Note 14 to our consolidated financial statements included in this report on Form 10-K for additional information. The decision to declare a dividend is reviewed quarterly by our Board of Directors. On February 3, 2023, our Board of Directors increased the quarterly dividend from \$0.4125 to \$0.4375 per common share.

## CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, borrowing capacity under our lines of credit, strong financial coverages, investment grade credit ratings and alternative financing arrangements such as leasing. Debt financing will be required in the five-year period from 2023 through 2027 to refinance maturing debt and to finance our capital investments within our Electric segment. Our financing plans are subject to change and

are impacted by our planned level of capital investments, a decision to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes.

## REGISTRATION STATEMENTS

On May 3, 2021, we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. The registration statement expires in May, 2024. No shares were issued pursuant to the registration statement in 2022.

On May 3, 2021, we filed a second registration statement with the SEC for the issuance of up to 1,500,000 common shares under an Automatic Dividend Reinvestment and Share Purchase Plan, which provides shareholders, retail customers of OTP and other interested investors a method of purchasing our common shares by reinvesting their dividends and/or making optional cash investments. Shares purchased under the plan may be new issue common shares or common shares purchased on the open market. The registration statement expires in May 2024. In 2022, we issued 133,827 shares under the plan. All shares issued under the plan to date have been open market purchases and there have been no new issue shares, resulting in no proceeds received by the Company. As of December 31, 2022, 1,250,993 shares remained available for purchase or issuance under the Plan.

## SHORT-TERM DEBT

OTC and OTP are each party to a credit agreement (the OTC Credit Agreement and OTP Credit Agreement, respectively) which provides for unsecured revolving lines of credit. On October 31, 2022, the credit agreements were amended to extend the maturity date of each credit facility from September 30, 2026 to October 29, 2027, and to replace the London Interbank Offered Rate (LIBOR) as a benchmark interest rate. The agreements generally bear interest at the Secured Overnight Financing Rate (SOFR) plus an applicable credit spread, which is subject to adjustment based on the credit ratings of the issuer. The weighted-average interest rate on all outstanding borrowings as of December 31, 2022 and 2021 was 5.61% and 1.42%.

The following is a summary of key provisions and borrowing information as of and for the year ended December 31, 2022:

<i>(in thousands, except interest rates)</i>	<b>OTC Credit Agreement</b>		<b>OTP Credit Agreement</b>	
Borrowing Limit	\$	170,000	\$	170,000
Borrowing Limit if Accordion Exercised <sup>1</sup>		290,000		250,000
Amount Restricted Due to Outstanding Letters of Credit at Year-End		—		9,573
Amount Outstanding at Year-End		—		8,204
Average Amount Outstanding During Year		11,686		22,698
Maximum Amount Outstanding During the Year		58,715		74,519
Interest Rate at Year-End		5.9 %		5.6 %
Expiration Date		October 29, 2027		October 29, 2027

<sup>1</sup>Each facility includes an accordion feature allowing the borrower to increase the borrowing limit if certain terms and conditions are met.

## LONG-TERM DEBT

At December 31, 2022, we had \$827.0 million of principal outstanding under long-term debt arrangements. Note 9 to our consolidated financial statements included in this report on Form 10-K includes information regarding these instruments. The agreements generally provide for unsecured borrowings at fixed rates of interest with maturities ranging from 2026 to 2052. One OTP debt instrument with a principal balance of \$30.0 million matured in August 2022. Pursuant to a Note Purchase Agreement executed in June 2021, OTP issued its Series 2022A notes in May 2022, for aggregate proceeds of \$90.0 million, and used a portion of the proceeds to repay the \$30.0 million which matured in August 2022.

### Financial Covenants

Certain of our short- and long-term debt agreements require OTC and OTP to maintain certain financial covenants. As of December 31, 2022, we were in compliance with these financial covenants as further described below:

**OTC**, under its financial covenants, may not permit its ratio of Interest-Bearing Debt to Total Capitalization to exceed 0.60 to 1.00, may not permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, and may not permit its Priority Indebtedness to exceed 10% of our Total Capitalization. As of December 31, 2022, our Interest-Bearing Debt to Total Capitalization was 0.41 to 1.00, our Interest and Dividend Coverage Ratio was 11.12 to 1.00 and we had no Priority Indebtedness outstanding.

**OTP**, under its financial covenants, may not permit its ratio of Debt to Total Capitalization to exceed 0.60 to 1.00, may not permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, and may not permit its Priority Debt to exceed 20% of its Total Capitalization. As of December 31, 2022, OTP's Interest-Bearing Debt to Total Capitalization was 0.45 to 1.00, its Interest and Dividend Coverage Ratio was 3.66 to 1.00 and it had no Priority Indebtedness outstanding.

None of our debt agreements include any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

## Credit Ratings

The credit ratings of OTC and OTP as of December 31, 2022 are summarized below:

	Otter Tail Corporation			Otter Tail Power Company		
	Moody's	Fitch	S&P	Moody's	Fitch	S&P
Corporate Credit/Long-Term Issuer Default Rating	Baa2	BBB-	BBB	A3	BBB	BBB+
Senior Unsecured Debt	n/a	BBB-	n/a	n/a	BBB+	BBB+
Outlook	Stable	Stable	Stable	Stable	Stable	Stable

## CRITICAL ACCOUNTING ESTIMATES

Preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and the Company's discussion and analysis of its financial condition and operating results requires management to make assumptions, estimates and judgments that affect the reported amounts. While we believe the estimates, assumptions, and judgments we use in preparing our consolidated financial statements are appropriate and are based on the best available information, they are subject to future events and uncertainties regarding their outcome and therefore actual results may materially differ from these estimates. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of our Board of Directors. The following critical accounting policies affect the most significant judgments and estimates used in the preparation of our consolidated financial statements.

### REGULATORY ACCOUNTING

Our utility business is subject to regulation of rates and other matters by state utility commissions in Minnesota, North Dakota and South Dakota and by the FERC for certain interstate operations. Accordingly, our utility business must adhere to the accounting requirements of regulated operations, which requires the recognition of regulatory assets and regulatory liabilities for amounts that otherwise would impact the statement of income or comprehensive income when it is probable that such amounts will be collected from customers or credited to customers through the rate-making process. This guidance also provides recognition criteria for adjustments to rates outside of a general rate case proceeding which are provided 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. Regulatory assets generally represent costs that have been incurred but have been deferred because future recovery from customers, as established through the rate-making process, is probable. Regulatory liabilities generally represent amounts to be refunded to customers or amounts currently collected from customers for future costs.

We assess the probability of recovery of regulatory assets and the obligations arising from regulatory liabilities on a quarterly basis. Our probability estimates incorporate numerous factors, including recent rate making decisions, historical precedents for similar matters, the regulatory environments in which we operate and the impact these incurred costs may have on our customers. Changes in our assessments regarding the likelihood of recovery or settlement of our regulatory assets and liabilities may have a material impact on our operating results and financial position. Further, if we determine that all or a portion of our utility business no longer meets the criteria for continued application of regulatory accounting, or our regulators disallow recovery of a previously incurred cost or eliminate a regulatory liability, we would be required to remove the associated regulatory assets and liabilities from our consolidated balance sheet and recognize in the consolidated statement of income as an expense or income item in the period in which this accounting treatment is no longer applicable.

As of December 31, 2022 and 2021, we had regulatory assets of \$119.7 million and \$152.9 million and regulatory liabilities of \$261.8 million and \$259.3 million. If future recovery of amounts recorded as regulatory assets was no longer probable we would be required to recognize expense or other comprehensive loss in the period in which recovery was deemed to no longer be probable.

### PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. See Note 10 to our consolidated financial statements included in this report on Form 10-K for additional information on our pension and postretirement benefit plans and related assumptions.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 30 or more years. These benefits can be paid out for up to 40 or more years after an employee retires. Estimates of liabilities and expenses related to these benefits are among our most critical accounting estimates. Although deferral and amortization of fluctuations in actuarially determined benefit obligations and expenses are provided for when actual results on a year-to-year basis deviate from long-range assumptions, compensation increases and healthcare cost increases or a reduction in the discount rate applied from one year to the next can significantly increase our benefit expenses in the year of the change. Likewise, compensation decreases and healthcare cost decreases or an increase in the discount rate applied from one year to the next can significantly decrease our benefit expenses in the year of the change. Also, a change in the expected rate of return on pension plan assets in our funded pension plan or realized rates of return on plan assets that are well above or below assumed rates of return or a change in the anticipated life expectancy of plan participants could result in significant increases or decreases in recognized pension benefit expenses in the year of the change or for many years thereafter because actuarial losses can be amortized over the average remaining service lives of active employees.

We estimate the discount rate through the use of a hypothetical bond portfolio method, which incorporates yields on a collection of high credit quality bonds that produce cash flows similar to our anticipated future benefit payments.

We estimate the assumed long-term rate of return on plan assets based on asset category studies using historical market returns achieved by our asset portfolio allocation over long-term periods, as well as long-term projected return levels.

Pension plan assets are invested in a portfolio according to our return, liquidity and diversification objectives to provide a source of funding for plan obligations and manage contributions to the plan. The principal process for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

At December 31, 2022, we set the discount rate used to measure our pension plan obligations at 5.51% and at 5.52% to measure postretirement healthcare obligations, a 248 and 251 basis point increase, respectively, from the estimates used at December 31, 2021. Our estimates used to determine benefit cost for 2022 included a discount rate of 3.03% for pension benefits and 3.01% for postretirement healthcare costs, a 25 and 26 basis point decrease, respectively, from 2021 estimates. In addition, we estimated our assumed rate of return on pension assets to be 6.30% for 2022, a 21 basis point decrease from our 2021 estimate.

The following table summarizes the impact on 2022 pension and postretirement costs for a 25 basis point increase or decrease, holding all other variables constant, on certain key assumptions:

<i>(in thousands)</i>	<b>+0.25</b>	<b>-0.25</b>
<b>Pension Plan:</b>		
Discount Rate	\$ (1,147)	\$ 1,207
Rate of Increase in Future Compensation	801	(757)
Long-Term Return on Plan Assets	(940)	940
<b>Other Postretirement Benefits:</b>		
Discount Rate	(310)	326

For 2023, we expect pension benefit income for our pension plan to be \$5.8 million compared to \$3.1 million of pension benefit expense in 2022, due to an increase in the discount rate used to determine benefit costs and an increase in the expected return on plan assets, partially offset by an increase in expected future compensation costs. The estimated discount rate used to determine annual benefit cost accruals increased from 3.03% in 2022 to 5.51% in 2023. The assumed rate of return on pension plan assets is 7.00% for 2023, compared with the assumption of 6.30% in 2022.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates, increases or decreases in the discount rate, increases in future compensation levels, and increases in retiree healthcare cost inflation rates could significantly change projected costs.

We believe the estimates made for our pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are subject to change.

#### **GOODWILL IMPAIRMENT**

Goodwill is required to be evaluated annually for impairment and more frequently as events or circumstances require. Goodwill is tested for impairment at the reporting unit level. We have identified two reporting units which carry a material amount of goodwill.

The goodwill impairment test is a single-step quantitative assessment which compares the estimated fair value of the reporting unit to its carrying value. An impairment charge is recognized if the carrying amount exceeds the estimated fair value in an amount that is equal to the excess but limited to the amount of recorded goodwill of the reporting unit. An optional qualitative impairment assessment may be performed prior to and may eliminate the need to perform the quantitative assessment.

Estimating the fair value of a reporting unit under the quantitative impairment method requires significant judgments and estimates. We estimate the fair value of our reporting units primarily using an income approach, which includes a discounted cash flow methodology to arrive at a fair value estimate by determining the present value of projected future cash flows over a specified period plus a terminal value to reflect cash flows beyond the projection period. The discount rate applied to the estimated future cash flows reflects our estimate of the weighted-average cost of capital of comparable entities. To supplement our income approach, we reference various market indications of fair value, where available, and include fair value estimates using multiples derived from comparable enterprise values to EBITDA, comparable price earnings ratios and, if available, comparable sales transactions for comparative peer companies.

Our discounted cash flow methodology incorporates significant estimates, which include assumptions of future operating results and cash flows, which are impacted by economic and industry conditions, the amount and timing of estimated capital expenditures, an estimated terminal growth rate and the selection of an appropriate weighted-average cost of capital, among others.

Our goodwill impairment testing performed in the fourth quarter of 2022 indicated no impairment was present for either reporting unit and the estimated fair value of each reporting unit substantially exceeded the respective carrying value. As part of our testing we perform various sensitivity analyses to understand if our conclusions are sensitive to changes in certain assumptions. A 1% decrease in projected operating revenues, a one hundred basis point decrease in projected gross profit margins and a twenty five basis point increase in the discount rate would not lead to a goodwill impairment charge for either reporting unit.

We believe the estimates and assumptions used in our impairment assessments are reasonable and based on the best information available. However, these estimates and assumptions inherently include a degree of uncertainty. Significant adverse changes in our expectations for any of these estimates could result in an impairment charge in a future period which may materially impact our operating results and financial position.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the potential loss arising from adverse changes in market rates and prices. We are primarily exposed to interest rate and commodity price risk.

### Commodity Price Risk

Our Electric segment business is exposed to market risk arising from changes in commodity prices for wholesale energy and natural gas. OTP purchases energy in the wholesale market to supplement its own electricity generation and to respond to changes in demand and variability in generating plant output. In addition, OTP procures natural gas as a fuel source for its combustion turbine peaking facilities. OTP's exposure to price risk for these commodities is largely mitigated by the current ratemaking process and regulatory framework, which generally allows recovery of purchased power and fuel costs from our electric customers.

OTP, where prudent, seeks to further manage its exposure to commodity price variability and reduce volatility in prices for its retail customers through the use of derivative instruments, primarily financial swap agreements. OTP does not engage in derivative and hedging activities for trading purposes. As of December 31, 2022, OTP was party to financial swap agreements with an aggregate notional amount of 295,000 megawatt-hours of electricity with various settlement dates throughout 2023. As of December 31, 2022, the aggregate fair value of these instruments was \$7.1 million, reflected as a liability on our consolidated balance sheet. Holding other variables constant, a ten percent change in energy prices would have had an approximate \$1.8 million impact on the fair value of these instruments.

Our Manufacturing segment businesses are exposed to market risk arising from changes in commodity prices for certain raw material inputs, including steel, aluminum, and polystyrene and other plastics resins. We attempt to manage commodity price risk by passing changes in the cost of these input materials through to our customers. If our efforts to manage commodity price risk are unsuccessful, the operating revenues and earnings of our Manufacturing segment could be impacted.

Our Plastics segment businesses are exposed to market risk arising from changes in prices for PVC resin, the primary raw material commodity used to manufacture PVC pipe. The PVC pipe industry as a whole is highly sensitive to volatility in PVC resin prices, with frequent adjustments to PVC pipe sale prices to reflect volatility in PVC resin costs. Historically, when resin prices are rising or stable, sales volumes have been higher. In contrast, when resin prices are falling, sales volumes have been lower. Due to the commodity nature of PVC resin and dynamic supply and demand factors worldwide, gross profit margins can fluctuate significantly from period to period.

We do not engage in any hedging activities within our Manufacturing and Plastics segments to manage our commodity price risk.

### Interest Rate Risk

Our exposure to interest rate risk arises from outstanding short-term debt which is subject to variable rates of interest based on benchmark interest rates, primarily SOFR. As of December 31, 2022 and 2021, we had \$8.2 million and \$91.2 million of short-term debt outstanding. Holding other variables constant, a one percentage point change in interest rates would have had an approximate \$0.3 million impact to interest charges in 2022 based on our average outstanding short-term debt during the year.

All of our outstanding long-term debt obligations as of December 31, 2022 and 2021 had fixed interest rates and were not subject to material interest rate risk. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, by limiting the amount of variable interest rate debt and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

We have not used hedging instruments to manage interest risk arising from our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

## ITEM 8. FINANCIAL STATEMENTS

### REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Otter Tail Corporation

#### Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Otter Tail Corporation and subsidiaries (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2022, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

#### Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

#### Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

#### Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

**Rate and Regulatory Matters—Impact of Rate Regulation on the Financial Statements—Refer to Notes 1 and 5 to the financial statements.**

Critical Audit Matter Description

The Company's regulated Electric segment accounts for the financial effects of regulation in accordance with ASC 980, Regulated Operations. This guidance allows for the recording of a regulatory asset or liability for certain costs or credits which otherwise would be recognized in the statement of income or comprehensive income based on an expectation that the cost will be recovered or returned in future rates. This guidance also provides 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.

The Company is subject to rate regulation by state and federal regulatory agencies (collectively, the "Commissions"), which have jurisdiction with respect to the rates of electric distribution companies in Minnesota, North Dakota and South Dakota. The Company assesses the probability of recovery of regulatory assets and the obligations arising from regulatory liabilities on a quarterly basis. Probability estimates incorporate numerous factors, including recent rate making decisions, historical precedents for similar matters, the regulatory environments in which the Company operates, and the impact that incurred costs may have on customers.

Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment, regulatory assets and liabilities, operating revenues and expenses, depreciation expense, income taxes and multiple disclosures in the notes to the financial statements. There is a risk that the Commissions will not approve full recovery of the costs of providing utility service or full recovery of all amounts invested in the utility business and a reasonable return on that investment. As a result, we identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital expenditures or operating costs that management believes were prudently incurred, and (3) a refund to customers. Given that management's accounting judgements are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due its inherent complexities.

*How the Critical Audit Matter Was Addressed in the Audit*

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant, and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared to management's recorded regulatory asset and liability balances for completeness.
- We inquired of management about property, plant, and equipment that may be abandoned. We inspected the capital-projects budget and construction-in-process listings and inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of the useful life. We inspected minutes of the board of directors and regulatory orders and other filings with the Commissions to identify any evidence that may contradict management's assertion regarding probability of an abandonment.
- We compared actual spend for projects that have been capitalized to property, plant, and equipment to budget. We evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects.
- We obtained an analysis from management and letters from internal and external legal counsel, as appropriate, regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota

February 15, 2023

We have served as the Company's auditor since 1944.

**OTTER TAIL CORPORATION**  
**CONSOLIDATED BALANCE SHEETS**

<i>(in thousands, except share data)</i>	<i>December 31,</i>	
	<b>2022</b>	<b>2021</b>
<b>Assets</b>		
Current Assets		
Cash and Cash Equivalents	\$ 118,996	\$ 1,537
Receivables, net of allowance for credit losses	144,393	174,953
Inventories	145,952	148,490
Regulatory Assets	24,999	27,342
Other Current Assets	18,412	17,032
Total Current Assets	452,752	369,354
Noncurrent Assets		
Investments	54,845	56,690
Property, Plant and Equipment, net of accumulated depreciation	2,212,717	2,124,605
Regulatory Assets	94,655	125,508
Intangible Assets, net of accumulated amortization	7,943	9,044
Goodwill	37,572	37,572
Other Noncurrent Assets	41,177	32,057
Total Noncurrent Assets	2,448,909	2,385,476
<b>Total Assets</b>	<b>\$ 2,901,661</b>	<b>\$ 2,754,830</b>
<b>Liabilities and Shareholders' Equity</b>		
Current Liabilities		
Short-Term Debt	\$ 8,204	\$ 91,163
Current Maturities of Long-Term Debt	—	29,983
Accounts Payable	104,400	135,089
Accrued Salaries and Wages	32,327	31,704
Accrued Taxes	19,340	19,245
Regulatory Liabilities	17,300	24,844
Other Current Liabilities	56,065	55,671
Total Current Liabilities	237,636	387,699
Noncurrent Liabilities and Deferred Credits		
Pensions Benefit Liability	33,210	73,973
Other Postretirement Benefits Liability	46,977	66,481
Regulatory Liabilities	244,497	234,430
Deferred Income Taxes	221,302	188,268
Deferred Tax Credits	15,916	16,661
Other Noncurrent Liabilities	60,985	62,527
Total Noncurrent Liabilities and Deferred Credits	622,887	642,340
Commitments and Contingencies (Note 13)		
Capitalization		
Long-Term Debt, net of current maturities	823,821	734,014
Shareholders' Equity		
Common Stock: 50,000,000 shares authorized of \$5 par value; 41,631,113 and 41,551,524 outstanding at December 31, 2022 and 2021	208,156	207,758
Additional Paid-In Capital	423,034	419,760
Retained Earnings	585,212	369,783
Accumulated Other Comprehensive Income (Loss)	915	(6,524)
Total Shareholders' Equity	1,217,317	990,777
Total Capitalization	2,041,138	1,724,791
<b>Total Liabilities and Shareholders' Equity</b>	<b>\$ 2,901,661</b>	<b>\$ 2,754,830</b>

See accompanying notes to consolidated financial statements.

**OTTER TAIL CORPORATION**  
**CONSOLIDATED STATEMENTS OF INCOME**

<i>(in thousands, except per-share amounts)</i>	<i>Years Ended December 31,</i>		
	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Operating Revenues</b>			
Electric	\$ 549,699	\$ 480,321	\$ 446,088
Product Sales	910,510	716,523	444,019
Total Operating Revenues	1,460,209	1,196,844	890,107
<b>Operating Expenses</b>			
Electric Production Fuel	65,110	59,327	46,296
Electric Purchased Power	100,281	65,409	61,698
Electric Operating and Maintenance Expenses	181,378	159,669	150,848
Cost of Products Sold (excluding depreciation)	542,944	488,370	329,257
Other Nonelectric Expenses	69,718	65,394	55,051
Depreciation and Amortization	92,597	91,358	82,037
Electric Property Taxes	17,742	17,609	17,034
Total Operating Expenses	1,069,770	947,136	742,221
<b>Operating Income</b>	<b>390,439</b>	<b>249,708</b>	<b>147,886</b>
<b>Other Income and Expense</b>			
Interest Charges	36,016	37,771	34,447
Nonservice Cost Components of Postretirement Benefits	(1,075)	2,016	3,437
Other Income (Expense), net	2,037	2,900	6,055
<b>Income Before Income Taxes</b>	<b>357,535</b>	<b>212,821</b>	<b>116,057</b>
Income Tax Expense	73,351	36,052	20,206
<b>Net Income</b>	<b>\$ 284,184</b>	<b>\$ 176,769</b>	<b>\$ 95,851</b>
<b>Weighted-Average Common Shares Outstanding:</b>			
Basic	41,586	41,491	40,710
Diluted	41,931	41,818	40,905
<b>Earnings Per Share:</b>			
Basic	\$ 6.83	\$ 4.26	\$ 2.35
Diluted	\$ 6.78	\$ 4.23	\$ 2.34

*See accompanying notes to consolidated financial statements.*

**OTTER TAIL CORPORATION**  
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Net Income</b>	\$ 284,184	\$ 176,769	\$ 95,851
<b>Other Comprehensive Income (Loss):</b>			
Unrealized (Loss) Gain on Available-for-Sale Securities, net of tax benefit (expense) of \$115, \$52 and \$(42)	<b>(432)</b>	(196)	155
Pension and Other Postretirement Benefit Plan, net of tax (expense) benefit of (\$2,769), \$(766) and \$796	<b>7,871</b>	2,179	(2,225)
<b>Total Other Comprehensive Income (Loss)</b>	<b>7,439</b>	1,983	(2,070)
<b>Total Comprehensive Income</b>	<b>\$ 291,623</b>	<b>\$ 178,752</b>	<b>\$ 93,781</b>

*See accompanying notes to consolidated financial statements.*

**OTTER TAIL CORPORATION**  
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**

<i>(in thousands, except common stock outstanding)</i>	<i>Common Stock Outstanding</i>	<i>Par Value, Common Stock</i>	<i>Additional Paid-In Capital</i>	<i>Retained Earnings</i>	<i>Accumulated Other Comprehensive Income (Loss)</i>	<i>Total Shareholders' Equity</i>
<b>Balance, December 31, 2019</b>	<b>40,157,591</b>	<b>\$ 200,788</b>	<b>\$ 364,790</b>	<b>\$ 222,341</b>	<b>\$ (6,437)</b>	<b>\$ 781,482</b>
Stock Issuances, Net of Expenses	868,484	4,342	32,466	—	—	36,808
Stock Issued Under Dividend Reinvestment and Stock Purchase Plans, Net of Expenses	365,267	1,826	13,221	—	—	15,047
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	78,537	393	(2,515)	—	—	(2,122)
Net Income	—	—	—	95,851	—	95,851
Other Comprehensive Loss	—	—	—	—	(2,070)	(2,070)
Stock Compensation Expense	—	—	6,284	—	—	6,284
Common Dividends (\$1.48 per share)	—	—	—	(60,314)	—	(60,314)
<b>Balance, December 31, 2020</b>	<b>41,469,879</b>	<b>\$ 207,349</b>	<b>\$ 414,246</b>	<b>\$ 257,878</b>	<b>\$ (8,507)</b>	<b>\$ 870,966</b>
Stock Issued Under Dividend Reinvestment and Stock Purchase Plans, Net of Expenses	11,540	58	446	—	—	504
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	70,105	351	(1,840)	—	—	(1,489)
Net Income	—	—	—	176,769	—	176,769
Other Comprehensive Income	—	—	—	—	1,983	1,983
Stock Compensation Expense	—	—	6,908	—	—	6,908
Common Dividends (\$1.56 per share)	—	—	—	(64,864)	—	(64,864)
<b>Balance, December 31, 2021</b>	<b>41,551,524</b>	<b>\$ 207,758</b>	<b>\$ 419,760</b>	<b>\$ 369,783</b>	<b>\$ (6,524)</b>	<b>\$ 990,777</b>
Employee Stock Purchase Plan Expenses	—	—	(219)	—	—	(219)
Stock Issued Under Share-Based Compensation Plans, Net of Shares Withheld for Employee Taxes	79,589	398	(3,321)	—	—	(2,923)
Net Income	—	—	—	284,184	—	284,184
Other Comprehensive Income	—	—	—	—	7,439	7,439
Stock Compensation Expense	—	—	6,814	—	—	6,814
Common Dividends (\$1.65 per share)	—	—	—	(68,755)	—	(68,755)
<b>Balance, December 31, 2022</b>	<b>41,631,113</b>	<b>\$ 208,156</b>	<b>\$ 423,034</b>	<b>\$ 585,212</b>	<b>\$ 915</b>	<b>\$ 1,217,317</b>

See accompanying notes to consolidated financial statements.

**OTTER TAIL CORPORATION**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Operating Activities</b>			
Net Income	\$ 284,184	\$ 176,769	\$ 95,851
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	92,597	91,358	82,037
Deferred Tax Credits	(745)	(744)	(1,221)
Deferred Income Taxes	32,424	28,896	15,201
Discretionary Contribution to Pension Plan	(20,000)	(10,000)	(11,200)
Allowance for Equity Funds Used During Construction	(1,690)	(822)	(4,063)
Stock Compensation Expense	6,814	6,908	6,284
Other, net	3,513	(3,035)	222
Changes in Operating Assets and Liabilities:			
Receivables	30,560	(60,994)	(6,328)
Inventories	5,339	(54,313)	5,686
Regulatory Assets	(2,464)	(4,803)	(4,070)
Other Assets	(368)	(14,146)	(5,227)
Accounts Payable	(29,763)	38,734	3,832
Accrued and Other Liabilities	(5,490)	28,386	19,262
Regulatory Liabilities	(6,846)	1,948	7,204
Pension and Other Postretirement Benefits	1,244	7,101	8,451
<b>Net Cash Provided by Operating Activities</b>	<b>389,309</b>	<b>231,243</b>	<b>211,921</b>
<b>Investing Activities</b>			
Capital Expenditures	(171,134)	(171,829)	(371,553)
Proceeds from Disposal of Noncurrent Assets	4,346	9,702	5,011
Purchases of Investments and Other Assets	(8,283)	(9,383)	(9,110)
<b>Net Cash Used in Investing Activities</b>	<b>(175,071)</b>	<b>(171,510)</b>	<b>(375,652)</b>
<b>Financing Activities</b>			
Net Borrowings (Repayments) on Short-Term Debt	(82,959)	10,166	74,997
Proceeds from Issuance of Common Stock	—	696	52,432
Proceeds from Issuance of Long-Term Debt	90,000	140,000	75,000
Payments for Retirement of Long-Term Debt	(30,000)	(140,169)	(182)
Dividends Paid	(68,755)	(64,864)	(60,314)
Payments for Shares Withheld for Employee Tax Obligations	(2,942)	(1,507)	(2,069)
Other, net	(2,123)	(3,681)	3,831
<b>Net Cash (Used in) Provided by Financing Activities</b>	<b>(96,779)</b>	<b>(59,359)</b>	<b>143,695</b>
<b>Net Change in Cash and Cash Equivalents</b>	<b>117,459</b>	<b>374</b>	<b>(20,036)</b>
<b>Cash and Cash Equivalents at Beginning of Period</b>	<b>1,537</b>	<b>1,163</b>	<b>21,199</b>
<b>Cash and Cash Equivalents at End of Period</b>	<b>\$ 118,996</b>	<b>\$ 1,537</b>	<b>\$ 1,163</b>
<b>Supplemental Disclosures of Cash Flow Information</b>			
Cash Paid During the Year for:			
Interest, net of amount capitalized	\$ 35,699	\$ 36,881	\$ 33,199
Income Taxes	\$ 43,411	\$ 8,445	\$ 5,177
<b>Supplemental Disclosure of Noncash Investing Activities</b>			
Accrued Property, Plant and Equipment Additions	\$ 12,420	\$ 12,081	\$ 34,265

*See accompanying notes to consolidated financial statements*

# **OTTER TAIL CORPORATION**

## **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

### **1. Summary of Significant Accounting Policies**

#### **Overview**

Otter Tail Corporation and its subsidiaries (collectively, the "Company", "us", "our" or "we") form a diverse, multi-platform business consisting of a vertically integrated, regulated utility with generation, transmission and distribution facilities complemented by manufacturing businesses providing metal fabrication for custom machine parts and metal components, manufacturing of extruded and thermoformed plastic products, and manufacturing of PVC pipe products. We classify our business into three segments: Electric, Manufacturing and Plastics. Note 2 includes an additional description of the segments and financial information regarding each segment.

#### **Principles of Consolidation**

These consolidated financial statements are presented in accordance with U.S. generally accepted accounting principles and include the accounts of OTC and its wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation except, as applicable, profits on sales to our regulated electric utility company from our nonregulated businesses, which is in accordance with the accounting requirements of regulated operations.

#### **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**

Our regulated electric utility company, Otter Tail Power Company, is subject to regulation of rates and other matters by state utility commissions in Minnesota, North Dakota and South Dakota and by the FERC for certain interstate operations. OTP accounts 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 statement of income or 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 statement of income or 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 income at the time they are reflected in customer rates. In the event OTP ceases 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 consolidated balance sheet and included in the consolidated statement of income as an expense or income item in the period in which the application of this guidance ceases.

#### **Cash Equivalents**

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

#### **Revenue from Contracts with Customers**

Due to our diverse business operations, the recognition of revenue from contracts with customers depends on the product produced and sold or service performed. 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. Depending on the product produced and sold or service performed and the terms of the agreement with the customer, we recognize revenue either over time, in the case of delivery or transmission of electricity or related services or the production and storage of certain custom-made products, or at a point in time for the delivery of standardized products and other products made to customer specifications where the terms of the contract require transfer of the completed product. Provisions for sales returns, early payment terms discounts, and volume-based variable pricing incentives are recorded as reductions to revenue at the time revenue is recognized based on customer history, historical information and current trends. We include revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold. Sales or other taxes collected from customers are excluded from operating revenues.

**Electric Segment Revenues.** Most Electric segment revenues are earned from the generation, transmission and sale of electricity to retail customers at rates approved by state regulatory commissions. OTP also earns revenue from the transmission of electricity for others over the transmission assets it owns separately, or jointly with other transmission service providers, under rate tariffs established by the independent transmission system operator and approved by the FERC. A third source of revenue for OTP 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 prior to the end of the reporting period, OTP records revenue and an unbilled receivable based on estimates of the kwh of energy delivered to the customer.

**Manufacturing Segment Revenues.** Our Manufacturing segment businesses earn revenue predominantly from the production and delivery of custom-made or standardized parts to customers across several industries and certain businesses also earn revenue from the production and sale of tools and dies to other manufacturers. For the production and delivery of standardized products and other products made to customer specifications where the terms of the contract require transfer of the completed product, we have met our performance obligation and recognize revenue at the point in time when the product is shipped. At this point we have no further obligation to provide services related to such products. The shipping terms used in these transactions are FOB shipping point.

**Plastics Segment Revenues.** Our Plastics segment businesses earn revenue predominantly from the sale and delivery of standardized PVC pipe products produced at their manufacturing facilities. Revenue from the sale of these products is recognized at the point in time when the product is shipped as there is no further obligation to provide services related to such products and the shipping terms are FOB shipping point. We have one customer within our Plastics segment for which we produce and store a product made to the customer's specifications and design under a build and hold agreement. For sales to this customer, we recognize revenue as the custom-made product is produced, adjusting the amount of revenue for volume rebate variable pricing considerations we expect the customer will earn and applicable early payment discounts we expect the customer will take. Ownership of the pipe transfers to the customer prior to delivery and we are paid a negotiated fee for storage of the pipe. Revenue for storage of the pipe is also recognized over time as the pipe is stored.

#### Alternative Revenue

In addition to recognizing revenue from contracts with customers, our Electric segment business also records 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 cost 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 ranging from 30 to 90 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 of our Electric segment are determined on an average cost basis. Costs for raw material, work in process and finished goods inventories of our Manufacturing and Plastics segments are determined on a first-in first-out (FIFO) basis.

Inventories consist of the following as of December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>		<b>2021</b>	
Finished Goods	\$	<b>43,812</b>	\$	39,903
Work in Process		<b>31,766</b>		35,705
Raw Material, Fuel and Supplies		<b>70,374</b>		72,882
<b>Total Inventories</b>	<b>\$</b>	<b>145,952</b>	<b>\$</b>	<b>148,490</b>

#### Investments

We invest in and hold, through a rabbi trust, corporate-owned life insurance policies to provide future funding for obligations under our supplemental pension plan and a non-qualified deferred compensation plan. The policies are recorded at cash surrender value and there are no restrictions on our ability to surrender the policies.

We hold debt, mutual fund investments and money market funds either as investments within our captive insurance entity or to provide future funding for obligations under non-qualified deferred compensation plans. These investments are recorded at fair value. Debt securities are deemed to be available-for-sale securities, accordingly unrealized gains and losses are generally excluded from earnings and recognized in accumulated other comprehensive income. We evaluate whether declines in fair value of debt securities below the cost basis are other-than-temporary. Declines in fair value deemed to be other-than-temporary result in the recognition of unrealized losses, or a portion thereof, in earnings. Unrealized gains and losses on mutual and money market funds are recognized in earnings immediately.

The following is a summary of our investments at December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>		<b>2021</b>	
Corporate-Owned Life Insurance Policies	\$	<b>38,991</b>	\$	41,078
Corporate and Government Debt Securities		<b>8,761</b>		9,202
Mutual Funds		<b>5,503</b>		5,432
Money Market Funds		<b>1,560</b>		949
Other Investments		<b>30</b>		29
<b>Total Investments</b>	<b>\$</b>	<b>54,845</b>	<b>\$</b>	<b>56,690</b>

The amount of unrealized gains and losses on debt securities as of December 31, 2022 and 2021 is not material and no unrealized losses were deemed to be other-than-temporary. In addition, the amount of unrealized gains and losses on marketable equity securities still held as of December 31, 2022 and 2021 is not material.

### Property, Plant and Equipment

Electric plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction (AFUDC). The amount of interest capitalized to electric plant was \$0.9 million in 2022, \$0.6 million in 2021 and \$2.1 million in 2020. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Removal costs, when incurred, are charged against the regulatory liability. Maintenance, repairs and replacement of minor items are charged to operating expenses as incurred. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property, plant and equipment of nonelectric operations are carried at historical cost and are depreciated on a straight-line basis over the assets' estimated useful lives. The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. No interest was capitalized in 2022, 2021 or 2020. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

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

<i>(years)</i>	<b>Service Life Range</b>	
	<b>Low</b>	<b>High</b>
<b>Electric Assets:</b>		
Production Plant	13	113
Transmission Plant	51	75
Distribution Plant	16	70
General Plant	5	60
<b>Nonelectric Assets:</b>		
Equipment	2	20
Buildings and Leasehold Improvements	2	40

### Jointly-Owned Facilities

OTP is 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. OTP is also a joint owner, with other regional utilities, in five major transmission lines. OTP's interest in each jointly-owned facility is reflected in the consolidated balance sheets on a pro-rata basis and OTP's share of direct revenue and expenses are included in operating revenues and expenses in the consolidated statements of income. Each participant in the jointly-owned facilities finances their own investments.

### Goodwill and Other Intangible Assets

Goodwill is recognized and initially measured as any excess of the acquisition-date consideration transferred in a business combination over amounts recognized for the net identifiable assets acquired. Goodwill is not amortized but is tested for impairment annually, or more frequently if an event occurs or circumstances change that would more likely than not result in an impairment of goodwill. Impairment testing is performed at the reporting unit level, which is defined as an operating segment or one level below an operating segment. We perform our impairment testing in the fourth quarter of each year and have identified three reporting units that carry a goodwill balance.

Our impairment testing includes both an optional qualitative assessment and the quantitative impairment assessment. Our qualitative assessment includes an analysis of relevant events and circumstances to determine if it is more likely than not that the fair value of the reporting unit exceeds its book value. If, after this assessment, we determine that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, no additional analysis is necessary. In contrast, if after the assessment we determine it is more likely than not that the fair value of a reporting unit is less than its carrying amount, or if we elect to skip the optional qualitative assessment, the quantitative impairment assessment is performed. The quantitative assessment is a single-step test that identifies both the existence of impairment and the amount of impairment loss by

comparing the estimated fair value of a reporting unit to its carrying value, with any excess carrying value over the fair value being recognized as an impairment loss.

Intangible assets with finite lives, which primarily consist of customer relationships, are carried at estimated fair value at the time of acquisition less accumulated amortization. The costs of the intangible assets are amortized over their estimated useful lives, which generally range from 15 to 20 years.

#### **Leases**

We recognize right-of-use lease assets and a corresponding lease liability at the lease commencement date. The length of our lease agreements varies from less than one year to approximately ten 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. Certain leases include variable lease payments as the amounts are subject to change over the lease term. 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 lessee entity.

#### **Recoverability of Long-Lived Assets**

We review our long-lived assets including, among other assets, property, plant and equipment, amortizing intangible assets 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.

#### **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 adjustment reflected in the ARO and associated long-lived asset.

#### **Income Taxes**

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. The realizability of deferred tax assets is determined by taking into consideration 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 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.

#### **Stock-Based Compensation**

Stock-based compensation awards are measured at the grant-date fair value of the award and compensation expense is recognized on a straight-line basis over the applicable service or performance period. The service period may be limited to the period until such time that a recipient is retirement eligible as determined under the award agreement. Awards granted to employees eligible for retirement on the date of grant are expensed in the period of grant. We recognize the effects of award forfeitures as they occur.

#### **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 an LSA with Coyote Creek Mining Company, L.L.C. , 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 consolidated 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 the Company is not required to include CCMC in its consolidated 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, OTP's maximum loss exposure, as a result of its involvement with CCMC, could be as high as \$45 million, or OTP's 35% share of CCMC's unrecovered costs as of December 31, 2022, if recovery of such a loss is denied by regulatory authorities.

## **2. Segment Information**

We classify our business into three segments, Electric, Manufacturing and Plastics, consistent with our business strategy, organizational structure and our internal reporting and review processes used by our chief operating decision maker to make decisions regarding allocation of resources, to assess operating performance and to make strategic decisions.

**Electric** includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is a participant in the MISO markets. OTP's operations have been our primary business since 1907.

**Manufacturing** consists of businesses in the following manufacturing activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

**Plastics** consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the western half of the United States and Canada.

Certain assets and costs are not allocated to our operating segments. Corporate operating costs include items such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment, rather it is added to operating segment totals to reconcile to consolidated amounts.

Information for each segment and our unallocated corporate costs for the years ended December 31, 2022, 2021 and 2020 are as follows:

<i>(in thousands)</i>	2022	2021	2020
<b>Operating Revenue</b>			
Electric	\$ 549,699	\$ 480,321	\$ 446,088
Manufacturing	397,983	336,294	238,770
Plastics	512,527	380,229	205,249
<b>Total</b>	<b>1,460,209</b>	<b>1,196,844</b>	<b>890,107</b>
<b>Depreciation and Amortization</b>			
Electric	72,050	71,343	63,171
Manufacturing	16,202	15,436	14,933
Plastics	4,205	4,354	3,604
Corporate	140	225	329
<b>Total</b>	<b>92,597</b>	<b>91,358</b>	<b>82,037</b>
<b>Operating Income (Loss)</b>			
Electric	113,138	106,964	107,083
Manufacturing	29,065	24,114	16,103
Plastics	264,578	132,760	37,823
Corporate	(16,342)	(14,130)	(13,123)
<b>Total</b>	<b>390,439</b>	<b>249,708</b>	<b>147,886</b>
<b>Interest Charges</b>			
Electric	31,950	33,043	29,848
Manufacturing	2,796	2,239	2,215
Plastics	585	587	644
Corporate	685	1,902	1,740
<b>Total</b>	<b>36,016</b>	<b>37,771</b>	<b>34,447</b>
<b>Income Tax Expense (Benefit)</b>			
Electric	5,065	1,663	12,480
Manufacturing	5,321	4,704	2,939
Plastics	68,688	34,374	9,718
Corporate	(5,723)	(4,689)	(4,931)
<b>Total</b>	<b>73,351</b>	<b>36,052</b>	<b>20,206</b>
<b>Net Income (Loss)</b>			
Electric	79,974	72,458	66,778
Manufacturing	20,950	17,186	11,048
Plastics	195,374	97,823	27,582
Corporate	(12,114)	(10,698)	(9,557)
<b>Total</b>	<b>284,184</b>	<b>176,769</b>	<b>95,851</b>
<b>Capital Expenditures</b>			
Electric	147,869	140,031	356,581
Manufacturing	17,954	20,690	10,587
Plastics	5,245	11,040	4,322
Corporate	66	68	63
<b>Total</b>	<b>\$ 171,134</b>	<b>\$ 171,829</b>	<b>\$ 371,553</b>

The following provides the identifiable assets by segment and corporate assets as of December 31, 2022 and 2021:

<i>(in thousands)</i>	2022	2021
<b>Identifiable Assets</b>		
Electric	\$ 2,351,961	\$ 2,283,776
Manufacturing	245,869	251,044
Plastics	126,318	162,565
Corporate	177,513	57,445
<b>Total</b>	<b>\$ 2,901,661</b>	<b>\$ 2,754,830</b>

### Concentrations

Our Plastics segment businesses use PVC resin as a critical component within their PVC pipe manufacturing process. There are a limited number of PVC resin suppliers in the U.S., and in 2022, we sourced all of our PVC resin needs from two vendors. Although there are a limited number of PVC resin suppliers, we believe that other suppliers could provide PVC resin on comparable terms. Additionally, most U.S. resin production plants are located in the Gulf Coast region. These plants are subject to the risk of damage and production shutdowns because of exposure to hurricanes or other extreme weather events that occur in this region. The loss of a key vendor, or any interruption or delay in the supply of PVC resin could cause production delays, a possible loss of sales, or result in increased costs to secure resin, all of which would adversely affect our operating results.

### Entity-Wide Information

No single customer accounted for over 10% of our consolidated operating revenues for the years ended December 31, 2022, 2021 and 2020. All of our long-lived assets are located within the United States and substantially all of our operating revenues are from customers located within the United States.

## 3. Revenue

We present our operating revenues from external customers, in total and by amounts arising from contracts with customers and ARP arrangements, disaggregated by revenue source and segment for the years ended December 31, 2022, 2021 and 2020:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Operating Revenues</b>			
<b>Electric Segment</b>			
Retail: Residential	\$ 143,888	\$ 135,361	\$ 127,260
Retail: Commercial and Industrial	318,494	262,408	254,951
Retail: Other	7,918	7,715	7,311
Total Retail	470,300	405,484	389,522
Transmission	52,213	48,835	44,001
Wholesale	18,539	17,936	4,857
Other	8,647	8,066	7,708
<b>Total Electric Segment</b>	<b>549,699</b>	<b>480,321</b>	<b>446,088</b>
<b>Manufacturing Segment</b>			
Metal Parts and Tooling	338,865	283,527	199,463
Plastic Products and Tooling	49,080	40,231	34,055
Scrap Metal	10,038	12,536	5,252
<b>Total Manufacturing Segment</b>	<b>397,983</b>	<b>336,294</b>	<b>238,770</b>
<b>Plastics Segment</b>			
PVC Pipe	512,527	380,229	205,249
<b>Total Operating Revenue</b>	<b>1,460,209</b>	<b>1,196,844</b>	<b>890,107</b>
<b>Less: Noncontract Revenues Included Above</b>			
Electric Segment - ARP Revenues	(9,266)	(791)	6,936
<b>Total Operating Revenues from Contracts with Customers</b>	<b>\$ 1,469,475</b>	<b>\$ 1,197,635</b>	<b>\$ 883,171</b>

## 4. Receivables

Receivables as of December 31, 2022 and 2021 are as follows:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
Receivables		
Trade	\$ 112,126	\$ 142,297
Other	9,983	10,591
Unbilled Receivables	23,932	23,901
Total Receivables	146,041	176,789
Less Allowance for Credit Losses	1,648	1,836
<b>Receivables, net of allowance for credit losses</b>	<b>\$ 144,393</b>	<b>\$ 174,953</b>

The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>		<b>2021</b>	
<b>Beginning Balance</b>	\$	<b>1,836</b>	\$	3,215
Additions Charged to Expense		<b>909</b>		93
Reductions for Amounts Written-Off, Net of Recoveries		<b>(1,097)</b>		(1,472)
<b>Ending Balance</b>	\$	<b>1,648</b>	\$	1,836

## 5. Regulatory Matters

### Regulatory Assets and Liabilities

The following presents our current and long-term regulatory assets and liabilities as of December 31, 2022 and 2021 and the period we expect to recover or refund such amounts:

<i>(in thousands)</i>	<i>Period of Recovery/Refund</i>	<b>2022</b>		<b>2021</b>	
		<i>Current</i>	<i>Long-Term</i>	<i>Current</i>	<i>Long-Term</i>
<b>Regulatory Assets</b>					
Pension and Other Postretirement Benefit Plans <sup>1</sup>	See below	\$ —	\$ 88,354	\$ 7,791	\$ 114,961
Alternative Revenue Program Riders <sup>2</sup>	Up to 2 years	5,679	2,508	11,889	5,564
Asset Retirement Obligations <sup>1</sup>	Asset lives	—	1,467	—	742
ISO Cost Recovery Trackers <sup>1</sup>	Up to 2 years	575	314	—	1,342
Unrecovered Project Costs <sup>1</sup>	Up to 5 years	320	990	2,136	1,455
Deferred Rate Case Expenses <sup>1</sup>	Up to 2 years	377	754	607	1,131
Debt Reacquisition Premiums <sup>1</sup>	Up to 10 years	25	216	100	240
Fuel Clause Adjustments <sup>1</sup>	Up to 1 year	10,893	—	4,819	—
Derivative Instruments <sup>1</sup>	Up to 1 year	7,130	—	—	—
Other <sup>1</sup>	Various	—	52	—	73
<b>Total Regulatory Assets</b>		<b>24,999</b>	<b>94,655</b>	27,342	125,508
<b>Regulatory Liabilities</b>					
Deferred Income Taxes	Asset lives	—	131,480	—	129,437
Plant Removal Obligations	Asset lives	8,509	105,733	8,306	101,595
Fuel Clause Adjustments	Up to 1 year	365	—	1,554	—
Alternative Revenue Program Riders	Various	2,504	7,136	5,772	3,336
Pension and Other Postretirement Benefit Plans	Up to 1 year	5,589	—	2,603	—
Derivative Instruments	Up to 1 year	—	—	6,214	—
Other	Various	333	148	395	62
<b>Total Regulatory Liabilities</b>		<b>\$ 17,300</b>	<b>\$ 244,497</b>	\$ 24,844	\$ 234,430

<sup>1</sup>Costs subject to recovery without a rate of return.

<sup>2</sup>Amount 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 subject to refund, respectively, primarily due to investments in qualifying transmission, conservation, renewable resource, environmental and other generation assets, and the impact of decoupling.

**Asset Retirement Obligations** represent the difference in timing of recognition of expense arising from these obligations and the amount recovered from customers.

**Independent System Operator (ISO) Cost Recovery Trackers** represent costs incurred to serve Minnesota customers for the under-collection of revenue based on expected versus actual construction costs on eligible projects.

**Unrecovered Project Costs** reflect costs incurred for abandoned generation and transmission assets and accelerated depreciation expense on a retired generation asset being recovered from customers.

**Deferred Rate Case Expenses** relate to costs incurred in conjunction with recent rate cases that are currently being recovered, or are expected to be recovered, from customers.

**Debt Reacquisition Premiums** represent costs to retire debt which are being recovered from customers over the remaining original lives of the reacquired debt.

**Fuel Clause Adjustments** represent the under- or over-collection of fuel costs to be collected from or returned to customers.

**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.

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

**Derivative Instruments** represent unrealized gains and losses recognized on derivative instruments. On final settlement of such instruments, any realized gains or losses are paid to or recovered from customers.

#### Minnesota Rate Case

On November 2, 2020, OTP filed an initial request with the MPUC for an increase in revenue recoverable through base rates in Minnesota, and on December 3, 2020, the MPUC approved an interim annual rate increase of \$6.9 million, or 3.2%, effective January 1, 2021.

On February 1, 2022, the MPUC issued its written order on final rates. The key provisions of the order included a revenue requirement of \$209.0 million, based on a return on rate base of 7.18% and an allowed ROE of 9.48% on an equity ratio of 52.5%. The order also authorized recovery of our remaining Hoot Lake Plant net asset over a five-year period and approved the requested decoupling mechanism for most residential and commercial customer rate groups with a cap of 4% of annual base revenues.

On May 12, 2022, OTP's final rate case compliance filing was approved by the MPUC. The filing included final revenue calculations, rate design and resulting tariff revisions, along with a determination of the interim rate refund, which resulted in an increase in revenues during 2022 of \$4.1 million. Final rates took effect on July 1, 2022, and interim rate refunds of \$15.3 million were applied to customer accounts.

#### MISO Resource Planning Auction

In 2022, we offered excess capacity into the annual MISO planning resource auction for the period June 2022 through May 2023. As a result of a capacity shortage in the MISO region, capacity prices cleared the auction at maximum pricing. During the year ended December 31, 2022, OTP recorded approximately \$5.3 million of excess capacity auction revenues. We anticipate the Minnesota allocated portion of net capacity auction revenues will be returned to customers through the FCA mechanism in the state, and a portion of the net capacity auction revenues allocated to our other jurisdictions will be used to mitigate customer rate increases or returned to customers through various mechanisms. At December 31, 2022, we recognized a reduction of a regulatory asset of \$2.6 million and a refund liability of \$1.8 million for net capacity auction revenues we anticipate will be refunded to customers.

## 6. Property, Plant and Equipment

Major classes of property, plant and equipment as of December 31, 2022 and 2021 include:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
<b>Electric Plant in Service</b>		
Production	\$ 1,343,097	\$ 1,332,067
Transmission	756,848	722,739
Distribution	612,716	574,488
General	131,718	129,151
Electric Plant in Service	2,844,379	2,758,445
Construction Work in Progress	113,932	74,926
Total Gross Electric Plant	2,958,311	2,833,371
Less Accumulated Depreciation and Amortization	859,988	817,302
Net Electric Plant	2,098,323	2,016,069
<b>Nonelectric Property, Plant and Equipment</b>		
Equipment	218,770	203,390
Buildings and Leasehold Improvements	61,506	56,908
Land	13,652	13,652
Nonelectric Property, Plant and Equipment	293,928	273,950
Construction Work in Progress	15,170	16,611
Total Gross Nonelectric Property, Plant and Equipment	309,098	290,561
Less Accumulated Depreciation and Amortization	194,704	182,025
Net Nonelectric Property, Plant and Equipment	114,394	108,536
<b>Net Property, Plant and Equipment</b>	<b>\$ 2,212,717</b>	<b>\$ 2,124,605</b>

Depreciation expense for the years ended December 31, 2022, 2021 and 2020 totaled \$84.4 million, \$85.8 million and \$78.6 million.

The following table provides OTP's ownership percentages and amounts included in the December 31, 2022 and 2021 consolidated balance sheets for OTP's share of each of these jointly-owned facilities:

<i>(dollars in thousands)</i>	<b>Ownership Percentage</b>	<b>Electric Plant in Service</b>	<b>Construction Work in Progress</b>	<b>Accumulated Depreciation</b>	<b>Net Plant</b>
<b>December 31, 2022</b>					
Big Stone Plant	53.9 %	\$ 338,411	\$ 557	\$ (118,044)	\$ 220,924
Coyote Station	35.0 %	183,461	2,315	(111,666)	74,110
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(5,587)	100,598
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(10,095)	68,089
Big Stone South–Brookings 345 kV line	50.0 %	53,041	—	(4,406)	48,635
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,291	—	(3,211)	23,080
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,318)	13,013
<b>December 31, 2021</b>					
Big Stone Plant	53.9 %	\$ 338,699	\$ 260	\$ (110,604)	\$ 228,355
Coyote Station	35.0 %	182,610	1,110	(107,894)	75,826
Big Stone South–Ellendale 345 kV line	50.0 %	106,194	—	(4,052)	102,142
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(9,069)	69,115
Big Stone South–Brookings 345 kV line	50.0 %	52,975	—	(3,613)	49,362
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,291	—	(2,843)	23,448
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(2,995)	13,336

## 7. Intangible Assets

The following table summarizes our goodwill by segment as of December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
Manufacturing	\$ 18,270	\$ 18,270
Plastics	19,302	19,302
<b>Total Goodwill</b>	<b>\$ 37,572</b>	<b>\$ 37,572</b>

Our annual goodwill impairment testing, performed in the fourth quarters of 2022 and 2021, indicated no impairment existed as of the test date.

The following table summarizes the components of our intangible assets at December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>Gross Amount</b>	<b>Accumulated Amortization</b>	<b>Net Carrying Amount</b>
<b>December 31, 2022</b>			
Customer Relationships	\$ 22,491	\$ 14,568	\$ 7,923
Other	26	6	20
Total	22,517	14,574	7,943
<b>December 31, 2021</b>			
Customer Relationships	22,491	13,469	9,022
Other	26	4	22
Total	\$ 22,517	\$ 13,473	\$ 9,044

Amortization expense for these intangible assets for each of the years ended December 31, 2022, 2021 and 2020 totaled \$1.1 million.

Annual amortization expense for these intangible assets for the next five years is:

<i>(in thousands)</i>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>
Amortization Expense	\$ 1,100	\$ 1,100	\$ 1,100	\$ 1,092	\$ 1,090

## 8. Leases

We lease rail cars, warehouse and office space, land and certain office, manufacturing and material handling 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, 2022 and 2021 are as follows:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
<b>Lease Cost</b>		
Operating Lease Cost	\$ 5,606	\$ 5,298
Variable Lease Cost	1,386	1,020
Short-Term Lease Cost	1,517	1,465
<b>Total Lease Cost</b>	<b>8,509</b>	<b>7,783</b>
<b>Lease Cash Flows</b>		
Operating Cash Flows from Operating Leases	\$ 5,592	\$ 5,642

A summary of operating lease right-of-use lease assets and lease liabilities as of December 31, 2022 and 2021 is as follows:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
Right of Use Lease Assets <sup>1</sup>	\$ 18,610	\$ 19,133
Lease Liabilities		
Current <sup>2</sup>	5,071	4,168
Long-Term <sup>3</sup>	13,876	15,309
<b>Total Lease Liabilities</b>	<b>\$ 18,947</b>	<b>\$ 19,477</b>

<sup>1</sup>Included in Other Noncurrent Assets in the consolidated balance sheets.

<sup>2</sup>Included in Other Current Liabilities in the consolidated balance sheets.

<sup>3</sup>Included in Other Noncurrent Liabilities in the consolidated balance sheets.

Operating lease assets obtained in exchange for new operating liabilities amounted to \$3.7 million and \$2.1 million for the years ended December 31, 2022 and 2021.

Maturities of lease liabilities as of December 31, 2022 for each of the next five years and in the aggregate thereafter are as follows:

<i>(in thousands)</i>	<b>Operating Leases</b>
2023	\$ 5,802
2024	5,263
2025	4,355
2026	2,544
2027	1,722
Thereafter	1,163
<b>Total Lease Payments</b>	<b>20,849</b>
Less: Interest	1,902
<b>Present Value of Lease Liabilities</b>	<b>\$ 18,947</b>

The weighted-average remaining lease term and the weighted-average discount rate as of December 31, 2022 and 2021 are as follows:

	<b>2022</b>	<b>2021</b>
Weighted-Average Remaining Lease Term (in years)	4.2	4.9
Weighted-Average Discount Rate	4.73 %	5.09 %

## 9. Short-Term and Long-Term Borrowings

The following is a summary of our outstanding short- and long-term borrowings by borrower, OTC or OTP, as of December 31, 2022 and 2021:

<i>(in thousands)</i>	2022			2021		
	OTC	OTP	Total	OTC	OTP	Total
Short-Term Debt	\$ —	\$ 8,204	\$ 8,204	\$ 22,637	\$ 68,526	\$ 91,163
Current Maturities of Long-Term Debt	—	—	—	—	29,983	29,983
Long-Term Debt, net of current maturities	79,798	744,023	823,821	79,746	654,268	734,014
<b>Total</b>	<b>\$ 79,798</b>	<b>\$ 752,227</b>	<b>\$ 832,025</b>	<b>\$ 102,383</b>	<b>\$ 752,777</b>	<b>\$ 855,160</b>

### Short-Term Debt

The following is a summary of our lines of credit as of December 31, 2022 and 2021:

<i>(in thousands)</i>	2022			2021	
	Line Limit	Amount Outstanding	Letters of Credit	Amount Available	Amount Available
OTC Credit Agreement	\$ 170,000	\$ —	\$ —	\$ 170,000	\$ 147,363
OTP Credit Agreement	170,000	8,204	9,573	152,223	88,315
<b>Total</b>	<b>\$ 340,000</b>	<b>\$ 8,204</b>	<b>\$ 9,573</b>	<b>\$ 322,223</b>	<b>\$ 235,678</b>

On October 31, 2022, OTC entered into a Fifth Amended and Restated Credit Agreement and OTP entered into a Fourth Amended and Restated Credit Agreement, in each case amending and restating the previously existing credit agreements to extend the maturity date of each credit facility from September 30, 2026 to October 29, 2027, and to replace LIBOR as a benchmark interest rate with SOFR. The adoption of SOFR as a benchmark interest rate is in advance of the scheduled elimination of LIBOR as a benchmark interest rate on June 30, 2023. No other significant terms or conditions, including borrowing capacity, credit spreads or financial covenants, were modified under these amendments and restatements. The agreements both provide for \$170.0 million unsecured revolving lines 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 \$40.0 million under the OTC Credit Agreement and \$50.0 million under the OTP Credit Agreement. Each credit facility includes an accordion provision allowing the borrower to increase the borrowing capacity under the facility, subject to certain conditions, up to \$290.0 million and \$250.0 million under the OTC Credit Agreement and OTP Credit Agreement, respectively.

Borrowings under each 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 respective 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 agreements, selected by the borrower at the time of an advance, subject to the conditions of each agreement, plus an applicable credit spread. The credit spread ranges from zero to 2.00%, depending on the benchmark interest rate selected and is subject to adjustment based on the credit ratings of the relevant borrower. The weighted-average interest rate on all outstanding borrowings as of December 31, 2022 and 2021 was 5.61% and 1.42%.

Each credit facility contains a number of restrictions on the borrower, 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 agreements also require the borrower to maintain various financial covenants, as further described below.

## Long-Term Debt

The following is a summary of outstanding long-term debt by borrower as of December 31, 2022 and 2021:

Entity	Debt Instrument	Rate	Maturity	(in thousands)	
				2022	2021
OTC	Guaranteed Senior Notes	3.55%	12/15/26	\$ 80,000	\$ 80,000
OTP	Series 2007B Senior Unsecured Notes	6.15%	08/20/22	—	30,000
OTP	Series 2007C Senior Unsecured Notes	6.37%	08/02/27	42,000	42,000
OTP	Series 2013A Senior Unsecured Notes	4.68%	02/27/29	60,000	60,000
OTP	Series 2019A Senior Unsecured Notes	3.07%	10/10/29	10,000	10,000
OTP	Series 2020A Senior Unsecured Notes	3.22%	02/25/30	10,000	10,000
OTP	Series 2020B Senior Unsecured Notes	3.22%	08/20/30	40,000	40,000
OTP	Series 2021A Senior Unsecured Notes	2.74%	11/29/31	40,000	40,000
OTP	Series 2007D Senior Unsecured Notes	6.47%	08/20/37	50,000	50,000
OTP	Series 2019B Senior Unsecured Notes	3.52%	10/10/39	26,000	26,000
OTP	Series 2020C Senior Unsecured Notes	3.62%	02/25/40	10,000	10,000
OTP	Series 2013B Senior Unsecured Notes	5.47%	02/27/44	90,000	90,000
OTP	Series 2018A Senior Unsecured Notes	4.07%	02/07/48	100,000	100,000
OTP	Series 2019C Senior Unsecured Notes	3.82%	10/10/49	64,000	64,000
OTP	Series 2020D Senior Unsecured Notes	3.92%	02/25/50	15,000	15,000
OTP	Series 2021B Senior Unsecured Notes	3.69%	11/29/51	100,000	100,000
OTP	Series 2022A Senior Unsecured Notes	3.77%	05/20/52	90,000	—
<b>Total</b>				<b>827,000</b>	<b>767,000</b>
	Less: Current Maturities Net of Unamortized Debt Issuance Costs			—	29,983
	Unamortized Long-Term Debt Issuance Costs			3,179	3,003
	<b>Total Long-Term Debt Net of Unamortized Debt Issuance Costs</b>			<b>\$ 823,821</b>	<b>\$ 734,014</b>

On June 10, 2021, OTP entered into a Note Purchase Agreement pursuant to which OTP agreed to issue, in a private placement transaction, \$230.0 million of senior unsecured notes consisting of (a) \$40.0 million of 2.74% Series 2021A Senior Unsecured Notes due November 29, 2031, (b) \$100.0 million of 3.69% Series 2021B Senior Unsecured Notes due November 29, 2051 and (c) \$90.0 million of 3.77% Series 2022A Senior Unsecured Notes due May 20, 2052. During the year ended December 31, 2021, OTP issued its Series 2021A and Series 2021B notes for aggregate proceeds of \$140.0 million, which were used to repay the Series 2011A notes. During the year ended December 31, 2022, OTP issued its Series 2022A notes for aggregate proceeds of \$90.0 million, which were used to repay the Series 2007B notes, to repay short-term borrowings, to fund capital expenditures, and for other general corporate purposes.

Our guaranteed and unsecured notes require the borrower 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 the borrowers, including its 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.

Aggregate maturities of long-term debt obligations at December 31, 2022 for each of the next five years are as follows:

(in thousands)	2023	2024	2025	2026	2027
Debt Maturities	\$ —	\$ —	\$ —	\$ 80,000	\$ 42,000

## Financial Covenants

Certain of OTC's and OTP's short-term and long-term debt agreements require the borrower, whether OTC or OTP, to maintain certain financial covenants, including a maximum debt to total capitalization of 0.60 to 1.00, a minimum interest and dividend coverage ratio of 1.50 to 1.00, and a maximum level of priority indebtedness. As of December 31, 2022, OTC and OTP were in compliance with these financial covenants.

## 10. Employee Postretirement Benefits

### Pension Plan and Other Postretirement Benefits

The Company sponsors a noncontributory funded pension plan (the Pension Plan), an unfunded, nonqualified Executive Survivor and Supplemental Retirement Plan (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 corporate and 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 the Company.

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 corporate and 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.** We have established a Retirement Plans Administration Committee to develop and monitor our investment strategy for our Pension Plan assets. Our 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, 2022 and 2021:

<i>Asset Class</i>	<b>Permitted</b>	<b>Actual Allocation</b>	
	<i>Range</i>	<b>2022</b>	<b>2021</b>
Return Enhancement	35 – 60%	<b>48 %</b>	47 %
Risk Management	40 – 80%	<b>51</b>	50
Alternatives	0 – 20%	<b>1</b>	3
<b>Total</b>		<b>100 %</b>	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, 2022 and 2021 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>
<b>December 31, 2022</b>					
Equity Funds	\$ 124,327	\$ —	\$ —	\$ —	\$ 124,327
Fixed Income Funds	156,424	—	—	—	156,424
Hybrid Funds	9,756	—	—	—	9,756
U.S. Treasury Securities	19,588	—	—	—	19,588
SEI Energy Debt Collective Fund	—	—	—	3,703	3,703
<b>Total</b>	<b>310,095</b>	<b>—</b>	<b>—</b>	<b>3,703</b>	<b>313,798</b>
<b>December 31, 2021</b>					
Equity Funds	149,479	—	—	—	149,479
Fixed Income Funds	184,987	—	—	—	184,987
Hybrid Funds	11,776	—	—	—	11,776
U.S. Treasury Securities	28,173	—	—	—	28,173
SEI Energy Debt Collective Fund	—	—	—	12,797	12,797
<b>Total</b>	<b>\$ 374,415</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 12,797</b>	<b>\$ 387,212</b>

The investments held by the SEI Energy Debt Collective Fund on December 31, 2022 and 2021 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 asset 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, 2022 and 2021 and the funded status of the plans as of December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>
<b>Change in Fair Value of Plan Assets:</b>						
Fair Value of Plan Assets at January 1	\$ 387,212	\$ 360,678	\$ —	\$ —	\$ —	\$ —
Actual Return on Plan Assets	(76,485)	32,816	—	—	—	—
Company Contributions	20,000	10,000	2,205	1,562	2,294	2,695
Benefit Payments	(16,930)	(16,282)	(2,205)	(1,562)	(8,173)	(8,385)
Participant Premium Payments	—	—	—	—	5,879	5,690
<b>Fair Value of Plan Assets at December 31</b>	<b>313,797</b>	<b>387,212</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>Change in Benefit Obligation:</b>						
Benefit Obligation at January 1	416,697	428,396	46,840	47,894	69,311	70,185
Service Cost	6,576	7,462	195	187	1,338	1,722
Interest Cost	12,344	11,660	1,341	1,228	2,041	1,891
Benefit Payments	(16,930)	(16,282)	(2,205)	(1,562)	(8,172)	(8,385)
Participant Premium Payments	—	—	—	—	5,879	5,690
Plan Amendments	—	—	—	—	—	—
Actuarial Loss	(110,632)	(14,539)	(10,547)	(907)	(20,450)	(1,792)
<b>Benefit Obligation at December 31</b>	<b>308,055</b>	<b>416,697</b>	<b>35,624</b>	<b>46,840</b>	<b>49,947</b>	<b>69,311</b>
<b>Funded Status</b>	<b>\$ 5,742</b>	<b>\$ (29,485)</b>	<b>\$ (35,624)</b>	<b>\$ (46,840)</b>	<b>\$ (49,947)</b>	<b>\$ (69,311)</b>
<b>Amounts Recognized in Consolidated Balance Sheet at December 31:</b>						
Noncurrent Assets	\$ 5,742	\$ —	\$ —	\$ —	\$ —	\$ —
Current Liabilities	—	—	(2,414)	(2,352)	(2,970)	(2,830)
Noncurrent Liabilities and Deferred Credits	—	(29,485)	(33,210)	(44,488)	(46,977)	(66,481)
<b>Net Asset (Liability)</b>	<b>\$ 5,742</b>	<b>\$ (29,485)</b>	<b>\$ (35,624)</b>	<b>\$ (46,840)</b>	<b>\$ (49,947)</b>	<b>\$ (69,311)</b>

The accumulated benefit obligation of our Pension Plan was \$283.2 million and \$378.3 million as of December 31, 2022 and 2021. The accumulated benefit obligation of our ESSRP was \$35.6 million and \$46.8 million as of December 31, 2022 and 2021.

The following assumptions were used to determine benefit obligations as of December 31, 2022 and 2021:

	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<b>2022</b>	<b>2021</b>	<b>2022</b>	<b>2021</b>	<b>2022</b>	<b>2021</b>
Discount Rate	<b>5.51 %</b>	3.03 %	<b>5.51 %</b>	2.93 %	<b>5.52 %</b>	3.01 %
Long-Term Rate of Compensation Increase <sup>(1)</sup>	<b>n/a</b>	n/a	<b>3.00 %</b>	3.00 %	<b>n/a</b>	n/a
Participants to Age 39 <sup>(1)</sup>	<b>4.50 %</b>	4.50 %	<b>n/a</b>	n/a	<b>n/a</b>	n/a
Participants Ages 40 to 49 <sup>(1)</sup>	<b>3.50 %</b>	3.50 %	<b>n/a</b>	n/a	<b>n/a</b>	n/a
Participants Age 50 and Older <sup>(1)</sup>	<b>2.75 %</b>	2.75 %	<b>n/a</b>	n/a	<b>n/a</b>	n/a
Healthcare Cost Immediate Trend Rate	<b>n/a</b>	n/a	<b>n/a</b>	n/a	<b>7.50 %</b>	6.16 %
Healthcare Cost Ultimate Trend Rate	<b>n/a</b>	n/a	<b>n/a</b>	n/a	<b>4.00 %</b>	4.50 %
Year the Rate Reaches the Ultimate Trend Rate	<b>n/a</b>	n/a	<b>n/a</b>	n/a	<b>2048</b>	2038

<sup>(1)</sup> The estimated rate of compensation increase for 2023 and 2024, as estimated as of December 31, 2022, is equal to 4.00% for all participants, reflecting higher anticipated compensation changes during these years.

The measurement of the plan asset 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 2022 and 2021 reduced our obligation by \$117.1 million and \$15.7 million. A short-term increase in expected future compensation increased the benefit obligation in 2022 by \$6.8 million. The difference between actual and expected returns on Pension Plan assets also impacted our obligation in 2022 and 2021.
- For the ESSRP, an increase in the discount rate in 2022 and 2021 reduced our obligation by \$10.2 million and \$1.7 million.
- For the postretirement healthcare plan, an increase in the discount rate in 2022 and 2021 reduced our obligation by \$17.9 million and \$2.6 million. Revised estimates of healthcare cost trends and participant contribution assumptions decreased the benefit obligation by \$2.4 million in 2022.

**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 consolidated statements of 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 consolidated statements of income, nonservice cost components are recognized as nonservice cost components of postretirement benefits.

The following table lists the components of net periodic benefit cost of our defined benefit pension plans and other postretirement benefits for the years ended December 31, 2022, 2021 and 2020:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>			<i>Pension Benefits (ESSRP)</i>			<i>Postretirement Benefits</i>		
	<b>2022</b>	<b>2021</b>	<b>2020</b>	<b>2022</b>	<b>2021</b>	<b>2020</b>	<b>2022</b>	<b>2021</b>	<b>2020</b>
Service Cost	\$ <b>6,576</b>	\$ 7,462	\$ 6,621	\$ <b>195</b>	\$ 187	\$ 179	\$ <b>1,338</b>	\$ 1,722	\$ 1,847
Interest Cost	<b>12,344</b>	11,660	13,053	<b>1,341</b>	1,228	1,449	<b>2,041</b>	1,891	2,393
Expected Return on Assets	<b>(23,684)</b>	(22,359)	(22,021)	—	—	—	—	—	—
Amortization of Prior Service Cost	—	—	—	—	—	—	<b>(5,733)</b>	(5,733)	(4,792)
Amortization of Net Actuarial Loss	<b>7,865</b>	10,914	9,144	<b>567</b>	620	434	<b>3,063</b>	3,774	4,310
<b>Net Periodic Benefit Cost</b>	<b>\$ 3,101</b>	\$ 7,677	\$ 6,797	<b>\$ 2,103</b>	\$ 2,035	\$ 2,062	<b>\$ 709</b>	\$ 1,654	\$ 3,758

The following table includes the impact of regulation on the recognition of periodic benefit cost arising from pension and other postretirement benefits for the years ended December 31, 2022, 2021 and 2020:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>	<b>2020</b>
Net Periodic Benefit Cost	\$ <b>5,913</b>	\$ 11,366	\$ 12,617
Net Amount Amortized (Deferred) Due to the Effect of Regulation	<b>1,121</b>	21	(533)
<b>Net Periodic Benefit Cost Recognized</b>	<b>\$ 7,034</b>	\$ 11,387	\$ 12,084

The following assumptions were used to determine net periodic benefit cost for the years ended December 31, 2022, 2021 and 2020:

	<i>Pension Benefits (Pension Plan)</i>			<i>Pension Benefits (ESSRP)</i>			<i>Postretirement Benefits</i>		
	<i>2022</i>	<i>2021</i>	<i>2020</i>	<i>2022</i>	<i>2021</i>	<i>2020</i>	<i>2022</i>	<i>2021</i>	<i>2020</i>
Discount Rate	<b>3.03 %</b>	2.78 %	3.47 %	<b>2.93 %</b>	2.61 %	3.36 %	<b>3.01 %</b>	2.75 %	3.43 %
Long-Term Rate of Return on Plan Assets	<b>6.30 %</b>	6.51 %	6.88 %	<b>n/a</b>	n/a	n/a	<b>n/a</b>	n/a	n/a
Long-Term Rate of Compensation Increase	<b>n/a</b>	n/a	n/a	<b>3.00 %</b>	3.00 %	3.50 %	<b>n/a</b>	n/a	n/a
Participants to Age 39	<b>4.50 %</b>	4.50 %	4.50 %	<b>n/a</b>	n/a	n/a	<b>n/a</b>	n/a	n/a
Participants Ages 40 to 49	<b>3.50 %</b>	3.50 %	3.50 %	<b>n/a</b>	n/a	n/a	<b>n/a</b>	n/a	n/a
Participants Age 50 and Older	<b>2.75 %</b>	2.75 %	2.75 %	<b>n/a</b>	n/a	n/a	<b>n/a</b>	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, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>
<b>Regulatory Assets (Liabilities):</b>						
Unrecognized Prior Service Cost	\$ —	\$ —	\$ —	\$ —	\$ (8,400)	\$ (13,989)
Unrecognized Actuarial Loss	<b>85,367</b>	102,737	<b>979</b>	2,525	<b>3,993</b>	26,852
<b>Net Regulatory Assets (Liabilities)</b>	<b>85,367</b>	102,737	<b>979</b>	2,525	<b>(4,407)</b>	12,863
<b>Accumulated Other Comprehensive Income (Loss):</b>						
Unrecognized Prior Service Cost	—	—	—	—	(99)	(242)
Unrecognized Actuarial (Gain) Loss	<b>(1,978)</b>	(1,020)	<b>1,093</b>	10,660	<b>(818)</b>	(160)
<b>Total Accumulated Other Comprehensive Income (Loss)</b>	<b>\$ (1,978)</b>	\$ (1,020)	<b>\$ 1,093</b>	\$ 10,660	<b>\$ (917)</b>	\$ (402)

**Cash Flows.** We made discretionary contributions to our Pension Plan of \$20.0 million, \$10.0 million and \$11.2 million in 2022, 2021 and 2020. As of December 31, 2022, 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:

<i>(in thousands)</i>	<i>2023</i>	<i>2024</i>	<i>2025</i>	<i>2026</i>	<i>2027</i>	<i>2028-2032</i>
Projected Pension Plan Benefit Payments	\$ 18,023	\$ 18,556	\$ 19,073	\$ 19,565	\$ 20,015	\$ 106,067
Projected ESSRP Benefit Payments	2,475	2,764	2,702	2,821	2,987	14,507
Projected Postretirement Benefit Payments	2,970	3,090	3,297	3,451	3,495	17,804
<b>Total</b>	<b>\$ 23,468</b>	<b>\$ 24,410</b>	<b>\$ 25,072</b>	<b>\$ 25,837</b>	<b>\$ 26,497</b>	<b>\$ 138,378</b>

#### **401K Plan**

We sponsor a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans totaled \$6.7 million for 2022, \$6.5 million for 2021 and \$5.3 million for 2020.

## **11. Asset Retirement Obligations**

We have recognized Asset Retirement Obligations (AROs) related to our coal-fired generation plants, natural gas combustion turbines and wind turbines. The cost of AROs include items such as site restoration, closure 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.

A reconciliation of the carrying amounts of AROs for the years ended December 31, 2022 and 2021 is as follows:

<i>(in thousands)</i>	<b>2022</b>		<b>2021</b>	
<b>Beginning Balance</b>	\$	<b>24,191</b>	\$	23,821
Adjustments Due to Revisions in Cash Flow Estimates		—		(568)
Accrued Accretion		<b>991</b>		938
<b>Ending Balance</b>	\$	<b>25,182</b>	\$	24,191

## 12. Income Taxes

Income before income taxes for the years ended December 31, 2022, 2021 and 2020 consists entirely of domestic earnings.

The provision for income taxes charged to income for the years ended December 31, 2022, 2021 and 2020 consisted of the following:

<i>(in thousands)</i>	<b>2022</b>		<b>2021</b>		<b>2020</b>	
<b>Current</b>						
Federal Income Taxes	\$	<b>31,949</b>	\$	6,806	\$	3,631
State Income Taxes		<b>9,568</b>		939		2,415
<b>Deferred</b>						
Federal Income Taxes		<b>22,480</b>		18,180		11,450
State Income Taxes		<b>9,943</b>		10,716		3,751
<b>Tax Credits</b>						
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		<b>(586)</b>		(586)		(1,033)
Investment Tax Credit Amortization		<b>(3)</b>		(3)		(8)
Total	\$	<b>73,351</b>	\$	36,052	\$	20,206

The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2022, 2021 and 2020 is as follows:

	<b>2022</b>		<b>2021</b>		<b>2020</b>	
Income Taxes at Federal Statutory Rate	\$	<b>75,082</b>	21.0 %	\$ 44,692	21.0 %	\$ 24,372 21.0 %
Increases (Decreases) in Tax from:						
State Taxes on Income, Net of Federal Tax	<b>15,049</b>	<b>4.2</b>	9,962	4.7	4,597	4.0
Production Tax Credits (PTCs)	<b>(14,985)</b>	<b>(4.2)</b>	(12,503)	(5.9)	(1,250)	(1.1)
Amortization of Excess Deferred Income Taxes	<b>(1,625)</b>	<b>(0.5)</b>	(4,262)	(2.0)	(4,167)	(3.6)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax	<b>(586)</b>	<b>(0.2)</b>	(586)	(0.3)	(1,033)	(0.9)
Allowance for Equity Funds Used During Construction	<b>(440)</b>	<b>(0.1)</b>	(214)	(0.1)	(796)	(0.7)
Other, Net	<b>856</b>	<b>0.3</b>	(1,037)	(0.5)	(1,517)	(1.3)
<b>Income Taxes at Effective Tax Rate</b>	<b>\$ 73,351</b>	<b>20.5 %</b>	\$ 36,052	16.9 %	\$ 20,206	17.4 %

We began to generate PTCs from our Merricourt wind farm in the fourth quarter of 2020, once the asset was placed in service and commenced operations.

Deferred tax assets and liabilities were composed of the following on December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
<b>Deferred Tax Assets</b>		
Employee Benefits	\$ 39,216	\$ 41,842
Regulatory Liabilities	57,353	75,293
Tax Credit Carryforwards, net of federal impact	20,209	27,965
Cost of Removal	37,360	26,512
Net Operating Loss Carryforward, net of federal impact	1,853	1,323
Other	12,107	11,067
Total Deferred Tax Assets	168,098	184,002
<b>Deferred Tax Liabilities</b>		
Differences Related to Property	(334,201)	(297,981)
Retirement Benefits Regulatory Asset	(22,789)	(40,766)
Pension Expense	(24,269)	(24,578)
Other	(8,141)	(8,945)
Total Deferred Tax Liabilities	(389,400)	(372,270)
<b>Deferred Income Taxes</b>	\$ (221,302)	\$ (188,268)

The following is a schedule of tax credits and tax net operating losses available as of December 31, 2022 and the respective periods of expiration:

<i>(in thousands)</i>	<b>Amount</b>	<b>2023-2029</b>	<b>2030-2037</b>	<b>2038-2043</b>
State Net Operating Losses	\$ 2,348	\$ —	\$ 2,348	\$ —
State Tax Credits	25,578	—	—	25,578

The following table summarizes the activity for unrecognized tax benefits for the years ended December 31, 2022, 2021 and 2020:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Balance on January 1</b>	\$ 827	\$ 771	\$ 1,488
Increases (decreases) for tax positions taken during a prior period	44	11	(178)
Increases for tax positions taken during the current period	260	189	175
Decreases due to settlements with taxing authorities	—	—	(575)
Decreases as a result of a lapse of applicable statutes of limitations	(208)	(144)	(139)
<b>Balance on December 31</b>	\$ 923	\$ 827	\$ 771

The balance of unrecognized tax benefits as of December 31, 2022 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2022 is not expected to change significantly within the next 12 months. We classify interest and penalties on tax uncertainties as components of the provision for income taxes in the consolidated statements of income.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2022, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2019 for federal and North Dakota income taxes and prior to 2018 for Minnesota state income taxes.

### 13. Commitments and Contingencies

#### Commitments

**Ashtabula III Purchase.** Since 2013, OTP had purchased the wind-generated electricity from the Ashtabula III, a 62.4-megawatt wind farm located in eastern North Dakota, pursuant to a power purchase agreement. That agreement granted OTP the option to purchase the wind farm, and in June 2022, OTP exercised its option. On January 3, 2023, OTP acquired Ashtabula III for \$50.6 million.

**Construction and Other Commitments.** As of December 31, 2022, OTP had commitments under contracts for construction project materials, plant maintenance, and other services extending into 2046 which totaled approximately \$21.5 million.

**Electric Utility Capacity and Energy Requirements.** OTP has commitments for the purchase of capacity and energy requirements under contractual agreements, including wind power purchase agreements extending into 2033. Generally, the terms of OTP's wind power purchase agreements require OTP to purchase all of the electricity generated by a particular wind farm and do not include fixed or minimum payments. The required payments are variable and the amounts due are determined based upon the amount of electricity generated. Capacity and energy requirement costs under these agreements totaled \$13.1 million, \$11.5 million and \$11.3 million for the years ended December 31, 2022, 2021 and 2020.

**Coal Purchase Commitments.** OTP has contracts providing for the purchase and delivery of its coal requirements. OTP's current coal purchase agreement with CCMC for Coyote Station expires 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. OTP has an agreement for the purchase of Big Stone Plant's coal requirements through December 31, 2024. There is no fixed minimum purchase requirement under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement. Coal purchase costs under these agreements totaled \$45.1 million, \$40.4 million and \$37.9 million for the years ended December 31, 2022, 2021 and 2020.

**Land Easement Payments.** OTP has commitments to make payments for land easements not classified as leases, extending into 2050 of approximately \$33.1 million. Land easement costs under these agreements totaled \$1.4 million, \$1.3 million and \$1.3 million for the years ended December 31, 2022, 2021 and 2020.

Our future commitments as of December 31, 2022 were as follows:

<i>(in thousands)</i>	<i>Construction Program and Other Commitments</i>	<i>Capacity and Energy Requirements</i>	<i>Coal Purchase Commitments</i>	<i>Land Easement Payments</i>
2023	\$ 12,423	\$ 298	\$ 23,955	\$ 1,388
2024	934	272	24,369	1,412
2025	472	228	25,103	1,437
2026	479	197	25,716	1,432
2027	487	197	25,804	1,457
Beyond 2027	6,660	3,939	402,500	26,004
<b>Total</b>	<b>\$ 21,455</b>	<b>\$ 5,131</b>	<b>\$ 527,447</b>	<b>\$ 33,130</b>

#### Contingencies

**FERC ROE.** In November 2013 and February 2015, customers filed complaints with the 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's most recent order, issued on November 19, 2020, 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. The U.S. Court of Appeals remanded the matter to FERC to reopen the proceedings.

Significant uncertainty exists as to how FERC will proceed on remand and there is no prescribed timeline under which FERC must act. We have deferred recognition and recorded a refund liability of \$2.6 million as of December 31, 2022. This refund liability reflects our best estimate of amounts previously collected from customers under the MISO tariff rate that may be required to be refunded to customers once all regulatory and judicial proceedings are complete and a final ROE is established for the periods outlined above.

**Regional Haze Rule (RHR).** The RHR was adopted in an effort to improve visibility in national parks and wilderness areas. The RHR requires states, in coordination with the Environmental Protection Agency and other governmental agencies, to develop and implement plans to achieve natural visibility conditions. The second RHR implementation period covers the years 2018-2028. States are required to submit a state implementation plan to assess reasonable progress with the RHR and determine what additional emission reductions are appropriate, if any.

Coyote Station, OTP's jointly-owned coal-fired power plant in North Dakota, is subject to assessment in the second implementation period under the North Dakota state implementation plan. The NDDEQ submitted its state implementation plan to the EPA for approval in August 2022. In its plan, the NDDEQ concluded it is not reasonable to require additional emission controls during this planning period. The EPA has previously expressed disagreement with the NDDEQ's recommendation to forgo additional emission controls and has indicated that such a plan is not likely to be accepted.

We cannot predict with certainty the impact the state implementation plan may have on our business until the state implementation plan has been approved or otherwise acted on by the EPA. However, significant emission control investments could be required and the recovery of such costs from customers would require regulatory approval. Alternatively, investments in emission control equipment may prove to be uneconomic and result in the early retirement of or the sale of our interest in Coyote Station, subject to regulatory approval. We cannot estimate the ultimate financial effects such a retirement or sale may have on our consolidated operating results, financial position or cash flows, but such amounts could be material and the recovery of such costs in rates would be subject to regulatory approval.

**Self-Funding of Transmission Upgrades.** The FERC has granted transmission owners within MISO 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 has 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 hearing, 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. On December 2, 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.

OTP, as a transmission owner in MISO, has exercised its authority and elected to self-fund previous transmission upgrades necessary to accommodate new system generation. Under such an election, OTP is recovering the cost of the transmission upgrade and a return on that investment from the generator over a contractual period of time. Should FERC, on remand from the Court of Appeals, 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 and when FERC may respond to the judicial remand.

**Other Contingencies.** We are party to litigation and regulatory enforcement matters arising in the normal course of business. We regularly analyze relevant information and, as necessary, estimate and record accrued liabilities for matters in which a loss is probable of occurring and can be reasonably estimated. We believe the effect on our consolidated operating results, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2022 will not be material.

## 14. Stockholders' Equity

### Capital Structure

In addition to authorized and outstanding common stock, the Company has 1,500,000 authorized no par value cumulative preferred shares and 1,000,000 authorized no par value cumulative preference shares. No cumulative preferred or cumulative preference shares were outstanding at December 31, 2022 or 2021.

### Shelf Registrations

On May 3, 2021, upon the expiration of a prior shelf registration, we filed a shelf registration statement with the SEC under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement. The registration statement expires in May 2024. No shares were issued pursuant to the shelf registration in 2022.

On May 3, 2021, upon the expiration of a second prior shelf registration, we filed a second registration statement with the SEC for the issuance of up to 1,500,000 common shares under an Automatic Dividend Reinvestment and Share Purchase Plan, which provides shareholders, retail customers of OTP and other interested investors a method of purchasing our common shares by reinvesting their dividends and/or making optional cash investments. Shares purchased under the plan may be new issue common shares or common shares purchased on the open market. In 2022, we issued 133,827 common shares under this program and no proceeds were received, as all shares issued were purchased on the open market. As of December 31, 2022, 1,250,993 shares remain available for purchase or issuance under the Plan. The shelf registration for the plan expires in May 2024.

### Dividend Restrictions

OTC is a holding company with no significant operations of its own. The primary source of funds for payments of dividends to our shareholders is from dividends paid or distributions made by OTC's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by OTC's subsidiaries. Both the OTC Credit Agreement and OTP Credit Agreement 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, 2022, 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 MPUC indirectly limits the amount of dividends OTP can pay to OTC by requiring an equity-to-total-capitalization ratio between 47.5% and 58.0%, with total capitalization not to exceed \$1.8 billion based on OTP's capital structure requirements as of December 31, 2022. As of December 31, 2022, OTP's equity-to-total-capitalization ratio including short-term debt was 54.7% and its net assets restricted from distribution totaled approximately \$737.4 million.

## 15. Accumulated Other Comprehensive Income (Loss)

The Company's other comprehensive income consists of unamortized actuarial losses and prior service costs related to pension and other postretirement benefits and unrealized gains and losses on marketable securities classified as available-for-sale. The income tax expense or benefit associated with amounts reclassified from accumulated other comprehensive income (loss) and reflected in the consolidated statement of 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, 2022, 2021 and 2020:

<i>(in thousands)</i>	<i>Pension and Other Postretirement Benefits</i>	<i>Net Unrealized Gain (Losses) on Available-for- Sale Securities</i>	<i>Total</i>
Balance, December 31, 2019	\$ (6,491)	\$ 54	\$ (6,437)
Other Comprehensive Income Before Reclassifications, net of tax	418	145	563
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(2,643) <sup>(1)</sup>	10 <sup>(2)</sup>	(2,633)
Total Other Comprehensive Income (Loss)	(2,225)	155	(2,070)
Balance, December 31, 2020	(8,716)	209	(8,507)
Other Comprehensive Income (Loss) Before Reclassifications, net of tax	1,638	(132)	1,506
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	541 <sup>(1)</sup>	(64) <sup>(2)</sup>	477
Total Other Comprehensive Income (Loss)	2,179	(196)	1,983
Balance, December 31, 2021	(6,537)	13	(6,524)
Other Comprehensive Income (Loss) Before Reclassifications, net of tax	7,331	(433)	6,898
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	540 <sup>(1)</sup>	1 <sup>(2)</sup>	541
Total Other Comprehensive Income (Loss)	7,871	(432)	7,439
<b>Balance, December 31, 2022</b>	<b>\$ 1,334</b>	<b>\$ (419)</b>	<b>\$ 915</b>

<sup>(1)</sup> Included in the computation of net periodic pension and other postretirement benefit costs. See Note 10 for further information.

<sup>(2)</sup> Included in other income (expense), net on the accompanying consolidated statements of income.

## 16. Share-Based Payments

### Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan authorizes the issuance of 1,400,000 common shares, allowing eligible employees to purchase our common shares through payroll withholding at a discount of up to 15% off the market price at the end of each six-month purchase period. Employee withholding amounts may not be less than \$10 or more than \$2,000 per month, subject to certain limitations, as described in the plan. A plan participant may cease making payroll deductions at any time. A participant may not purchase more than 2,000 shares in a given six month purchase period under the plan and may not purchase more than \$25,000 (fair market value) of common shares under the plan and all other purchase plans (if any) in a calendar year. A participant may withdraw from the plan at any time and elect to receive the balance of their contributions to the plan that have not yet been used to purchase shares in cash. Shares purchased under the plan are automatically enrolled in the Company's dividend reinvestment plan. Shares purchased under the plan may not be assigned, transferred, pledged, or otherwise disposed, except for certain situations allowed by the plan, such as upon death, for a period of 18 months after purchase. At our discretion, shares purchased under the plan can be either new issue shares or shares purchased in the open market. The plan shall automatically terminate when all of the shares authorized under the plan have been issued.

We recognize the 15% discount to the fair market value of the purchased shares as stock-based compensation expense, which amounted to \$0.3 million, \$0.2 million and \$0.2 million for the years ended December 31, 2022, 2021, and 2020. For the years ended December 31, 2022, 2021, and 2020 the amount of shares issued under the plan amounted to 26,420, 27,975 and 31,661 shares. As of December 31, 2022, there were 263,706 shares available for purchase under the plan.

### Share-Based Compensation Plan

The 2014 Stock Incentive Plan, which was approved by our shareholders in April 2014, authorizes the issuance of 1,900,000 common shares for the granting of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards and other stock and stock-based awards. As of December 31, 2022, 587,211 shares were available for issuance under the plan. The plan terminates on December 31, 2023.

We grant restricted stock awards to our employees and members of our Board of Directors and stock performance awards to our executive officers and certain other key employees as part of our long-term compensation and retention program. Stock-based compensation cost, recognized within operating expenses in the consolidated statements of income, amounted to \$6.6 million, \$6.7 million and \$6.1 million for the years ended December 31, 2022, 2021 and 2020. The related income tax benefit recognized for these periods amounted to \$1.7 million, \$1.8 million and \$2.1 million.

**Restricted Stock Awards.** Restricted stock awards are granted to executive officers and other key employees and members of the Company's Board of Directors. The awards vest, depending on award recipient, either ratably over a period of three to four years or cliff vest after four years. Vesting is accelerated in certain circumstances, including upon retirement. Awards granted to members of the Board of Directors are issued and

outstanding upon grant and carry the same voting and dividend rights of unrestricted outstanding common stock. Awards granted to executive officers and other key employees are eligible to receive dividend equivalent payments during the vesting period, subject to forfeiture under the terms of the agreement, but such awards are not issued or outstanding upon grant and do not provide for voting rights.

The grant-date fair value of each restricted stock award is determined based on the market price of the Company's common stock on the date of grant adjusted to exclude the value of dividends for those awards that do not receive dividend or dividend equivalent payments during the vesting period.

The following is a summary of restricted stock award activity for the year ended December 31, 2022:

	<i>Shares</i>	<i>Weighted-Average Grant-Date Fair Value</i>
Nonvested, Beginning of Year	138,093	\$ 44.48
Granted	51,600	59.95
Vested	(48,142)	45.35
Forfeited	—	—
Nonvested, End of Year	141,551	\$ 49.83

The weighted-average grant-date fair value of granted awards was \$59.95, \$43.55 and \$45.97 during the years ended December 31, 2022, 2021 and 2020. The fair value of vested awards was \$3.0 million, \$2.1 million and \$2.8 million during the years ended December 31, 2022, 2021 and 2020. As of December 31, 2022, there was \$2.9 million of unrecognized compensation costs for unvested restricted stock awards to be recognized over a weighted-average period of 1.84 years.

**Stock Performance Awards.** Stock performance awards are granted to executive officers and certain other key employees. The awards vest at the end of a three-year performance period. The number of common shares awarded, if any, at the end of the performance period ranges from zero to 150% of the target amount based on two performance measures: i) total shareholder return relative to a peer group (TSR component) and ii) return on equity (ROE component). The awards have no voting or dividend rights during the vesting period. Vesting of the awards is accelerated in certain circumstances, including upon retirement. The amount of common shares awarded on an accelerated vesting is based either on actual performance at the end of the performance period or the amount of common shares earned at target.

The grant-date fair value of the ROE component of the stock performance awards granted during the years ended December 31, 2022, 2021 and 2020 was determined using the grant date stock price and a discounted cash flow analysis to adjust for expected unearned dividends during the vesting period. The grant-date fair value of the TSR component of the stock performance awards granted during the years ended December 31, 2022, 2021 and 2020 was determined using a Monte Carlo fair value simulation model incorporating the following assumptions:

	<b>2022</b>	<b>2021</b>	<b>2020</b>
Risk-free interest rate	<b>1.52 %</b>	0.18 %	1.42 %
Expected term (in years)	<b>3.00</b>	3.00	3.00
Expected volatility	<b>32.00 %</b>	32.00 %	19.00 %
Dividend yield	<b>2.90 %</b>	3.60 %	2.80 %

The risk-free interest rate was derived from yields on U.S. government bonds of a similar term. The expected term of the award is equal to the three-year performance period. Expected volatility was estimated based on actual historical volatility of our common stock over a three- or five-year period. Dividend yield was estimated based on historic and future yield estimates.

The following is a summary of stock performance award activity for the year ended December 31, 2022 (share amounts reflect awards at target):

	<i>Shares</i>	<i>Weighted-Average Grant-Date Fair Value</i>
Nonvested, Beginning of Year	189,600	\$ 42.54
Granted	55,800	54.91
Vested	(55,600)	43.30
Forfeited	—	—
Nonvested, End of Year	189,800	\$ 45.95

The weighted-average grant-date fair value of granted awards was \$54.91, \$38.34 and \$47.79 during the years ended December 31, 2022, 2021 and 2020. The fair value of vested awards was \$5.1 million, \$2.5 million and \$3.4 million during the years ended December 31, 2022, 2021 and 2020. As of December 31, 2022, there was \$0.4 million of unrecognized compensation costs of unvested stock performance awards to be recognized over a weighted-average period of 0.91 years.

## 17. Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per share is net income. The denominator used in the calculation of basic earnings per share is the weighted-average number of shares outstanding during the period. The denominator used in the calculation of diluted earnings per share is derived by adjusting basic shares outstanding for the dilutive effect of potential shares outstanding, which consist of time and performance based stock awards and employee stock purchase plan shares.

The following includes the computation of the denominator for basic and diluted weighted-average shares outstanding for the years ended December 31, 2022, 2021 and 2020:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Weighted Average Common Shares Outstanding – Basic</b>	<b>41,586</b>	41,491	40,710
Effect of Dilutive Securities:			
Stock Performance Awards	<b>248</b>	226	116
Restricted Stock Awards	<b>95</b>	87	63
Employee Stock Purchase Plan Shares and Other	<b>2</b>	14	16
Dilutive Effect of Potential Common Shares	<b>345</b>	327	195
<b>Weighted Average Common Shares Outstanding – Diluted</b>	<b>41,931</b>	41,818	40,905

The amount of shares excluded from diluted weighted-average common shares outstanding because such shares were anti-dilutive was not material for the years ended December 31, 2022, 2021 and 2020.

## 18. Derivative Instruments

OTP enters into derivative instruments to manage its exposure to future commodity price variability and reduce volatility in prices for our retail electric customers. These derivative instruments are not designated as qualifying hedging transactions but provide for an economic hedge against future price variability. The instruments are recorded at fair value on the consolidated balance sheets, with changes in fair value recorded in the consolidated statements of income. However, 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, 2022 and 2021, OTP had outstanding pay-fixed, receive-variable swap agreements with an aggregate notional amount of 295,000 and 263,400 megawatt-hours of electricity. The contracts outstanding as of December 31, 2022 had various settlement dates throughout 2023. As of December 31, 2022 and 2021, the fair value of these derivative instruments was \$7.1 million, which is included in other current liabilities, and 6.2 million, which is included in other current assets, on the consolidated balance sheets. During the years ended December 31, 2022 and 2021, contracts matured and were settled in an aggregate amount of \$1.0 million and \$3.1 million.

## 19. Fair Value Measurements

The following tables present our assets measured at fair value on a recurring basis as of December 31, 2022 and 2021 classified by the input method used to measure fair value:

	<i>Level 1</i>	<i>Level 2</i>	<i>Level 3</i>
<b>December 31, 2022</b>			
<b>Assets</b>			
Investments:			
Money Market Funds	\$ 1,560	\$ —	\$ —
Mutual Funds	5,503	—	—
Corporate Debt Securities	—	1,434	—
Government-Backed and Government-Sponsored Enterprises' Debt Securities	—	7,327	—
Total Assets	7,063	8,761	—
<b>Liabilities</b>			
Derivative Instruments	—	7,130	—
Total Liabilities	\$ —	\$ 7,130	\$ —

### December 31, 2021

<b>Assets</b>			
Investments:			
Money Market Funds	\$ 949	\$ —	\$ —
Mutual Funds	5,432	—	—
Corporate Debt Securities	—	1,333	—
Government-Backed and Government-Sponsored Enterprises' Debt Securities	—	7,869	—
Derivative Instruments	—	6,214	—
Total Assets	\$ 6,381	\$ 15,416	\$ —

The level 2 fair value measurements for government-backed and government-sponsored enterprises' and corporate debt securities are determined on the basis of valuations provided by a third-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service may be based on broker quotes.

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 recorded at fair value on a recurring basis, we also hold financial instruments that are not recorded at fair value in the consolidated 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, 2022 and 2021:

<i>(in thousands)</i>	<i>December 31, 2022</i>		<i>December 31, 2021</i>	
	<i>Carrying Amount</i>	<i>Fair Value</i>	<i>Carrying Amount</i>	<i>Fair Value</i>
<b>Assets:</b>				
Cash and Cash Equivalents	\$ 118,996	\$ 118,996	\$ 1,537	\$ 1,537
Total	118,996	118,996	1,537	1,537
<b>Liabilities:</b>				
Short-Term Debt	8,204	8,204	91,163	91,163
Long-Term Debt	823,821	681,615	763,997	878,272
Total	\$ 832,025	\$ 689,819	\$ 855,160	\$ 969,435

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

**Cash Equivalents:** The carrying amount approximates fair value because of the short-term maturity of these instruments.

**Short-Term Debt:** The carrying amount approximates fair value because the debt obligations are short-term in nature and 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.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

**Evaluation of Disclosures Controls and Procedures.** Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2022, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2022.

**Changes in Internal Control over Financial Reporting.** There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

**Management's Report Regarding Internal Control Over Financial Reporting.** Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this report on Form 10-K. The consolidated financial statements of the Company have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). These internal controls are designed only to provide reasonable assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition.

Management has completed its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework (2013)* to conduct the required assessment of the effectiveness of the Company's internal control over financial reporting. Based on this assessment, management concluded that, as of December 31, 2022, the Company's internal control over financial reporting was effective based on those criteria. The Company's independent registered public accounting firm, Deloitte & Touche LLP, has audited the Company's consolidated financial statements included in this report on Form 10-K and issued an attestation report on the Company's internal control over financial reporting.

**Attestation Report of Independent Registered Public Accounting Firm.** The attestation report of Deloitte & Touche LLP, the Company's independent registered public accounting firm, regarding the Company's internal control over financial reporting is provided in Item 8 of this report on Form 10-K.

## ITEM 9B. OTHER INFORMATION

None.

## ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

## PART III

### ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under “Election of Directors” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A of this report on Form 10-K. The information required by this Item regarding the Company’s procedures for recommending nominees to the board of directors is incorporated by reference to the information under “Corporate Governance – Director Nomination Process” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting. The information required by this Item regarding the Audit Committee and the Company’s Audit Committee financial experts is incorporated by reference to the information under “Committees of the Board of Directors – Audit Committee” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

The Company has adopted a code of business ethics that applies to all of its directors, officers (including its principal executive officer, principal financial officer, and its principal accounting officer or controller or person performing similar functions) and employees. The Company’s code of business ethics is available on its website at [www.ottertail.com](http://www.ottertail.com). The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of business ethics by posting such information on its website at the address specified above. Information on the Company’s website is not deemed to be incorporated by reference into this report on Form 10-K.

### ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under “Compensation Discussion and Analysis”, “Report of Compensation and Human Capital Management Committee”, “Executive Compensation”, “Pay Ratio Disclosure” and “Director Compensation” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

### ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item regarding the Company’s equity compensation plans is incorporated by reference to the information under “Equity Compensation Plan Information” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting. The information required by this Item regarding security ownership is incorporated by reference to the information under “Security Ownership of Certain Beneficial Owners” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

### ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information under “Policy and Procedures Regarding Transactions with Related Persons”, “Election of Directors” and “Committees of the Board of Directors” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

### ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under “Ratification of Independent Registered Public Accounting Firm – Fees” and “Ratification of Independent Registered Public Accounting Firm – Pre-Approval of Audit/Non-Audit Services Policy” in the Company’s definitive Proxy Statement for the 2023 Annual Meeting.

## PART IV

### ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

#### 1. Financial Statements

	<i>Page</i>
<a href="#">Report of Independent Registered Public Accounting Firm</a>	39
<a href="#">Consolidated Balance Sheets</a>	41
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<a href="#">Consolidated Statements of Comprehensive Income</a>	43
<a href="#">Consolidated Statements of Shareholders' Equity</a>	44
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#### 2. Financial Statement Schedules

Schedule I - Condensed Financial Information of Registrant

Schedule II - Valuation and Qualifying Accounts and Reserves

**SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT  
 OTTER TAIL CORPORATION (PARENT COMPANY)  
 CONDENSED BALANCE SHEETS**

<i>(in thousands)</i>	<i>December 31,</i>	
	<b>2022</b>	<b>2021</b>
<b>Assets</b>		
Current Assets		
Cash and Cash Equivalents	\$ 119,246	\$ 3
Accounts Receivable	—	25
Accounts Receivable from Subsidiaries	3,278	2,817
Interest Receivable from Subsidiaries	117	117
Notes Receivable from Subsidiaries	—	6,767
Other	1,045	1,410
Total Current Assets	123,686	11,139
Investments in Subsidiaries	1,463,998	1,184,564
Notes Receivable from Subsidiaries	78,900	78,900
Deferred Income Taxes	64,802	29,619
Other Assets	43,779	44,749
<b>Total Assets</b>	<b>\$ 1,775,165</b>	<b>\$ 1,348,971</b>
<b>Liabilities and Stockholders' Equity</b>		
Current Liabilities		
Short-Term Debt	\$ —	\$ 22,637
Accounts Payable to Subsidiaries	7	181
Notes Payable to Subsidiaries	420,363	190,204
Other	15,994	14,526
Total Current Liabilities	436,364	227,548
Other Noncurrent Liabilities	41,686	50,900
Commitments and Contingencies		
Capitalization		
Long-Term Debt, Net of Current Maturities	79,798	79,746
Common Stockholders' Equity	1,217,317	990,777
Total Capitalization	1,297,115	1,070,523
<b>Total Liabilities and Stockholders' Equity</b>	<b>\$ 1,775,165</b>	<b>\$ 1,348,971</b>

*See accompanying notes to condensed financial statements.*

**OTTER TAIL CORPORATION (PARENT COMPANY)**  
**CONDENSED STATEMENTS OF INCOME**

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Income</b>			
Equity Income in Earnings of Subsidiaries	\$ 296,833	\$ 188,375	\$ 106,379
Interest Income from Subsidiaries	3,382	2,826	2,859
Other Income	466	1,290	1,317
Total Income	300,681	192,491	110,555
<b>Expense</b>			
Operating Expenses	17,269	14,825	14,007
Interest Charges	4,066	4,727	4,599
Interest Charges from Subsidiaries	5	3	136
Nonservice Cost Components of Postretirement Benefits	1,023	1,097	1,150
Total Expense	22,363	20,652	19,892
<b>Income Before Income Taxes</b>	<b>278,318</b>	<b>171,839</b>	<b>90,663</b>
Income Tax Benefit	5,866	4,930	5,188
<b>Net Income</b>	<b>\$ 284,184</b>	<b>\$ 176,769</b>	<b>\$ 95,851</b>

*See accompanying notes to condensed financial statements.*

**OTTER TAIL CORPORATION (PARENT COMPANY)**  
**CONDENSED STATEMENTS OF CASH FLOWS**

<i>(in thousands)</i>	<i>Years Ended December 31,</i>		
	<b>2022</b>	<b>2021</b>	<b>2020</b>
<b>Cash Flows from Operating Activities</b>			
Net Cash Provided by Operating Activities	\$ 28,807	\$ 60,695	\$ 54,027
<b>Cash Flows from Investing Activities</b>			
Investment in Subsidiaries	(50,000)	—	(150,000)
Debt Repaid by Subsidiaries	—	169	182
Other, net	(1,695)	(884)	(2,419)
Net Cash Used in Investing Activities	(51,695)	(715)	(152,237)
<b>Cash Flows from Financing Activities</b>			
Net (Repayments) Borrowings on Short-Term Debt	(22,637)	(42,529)	59,166
Borrowings from Subsidiaries	236,926	49,085	44,741
Proceeds from Issuance of Common Stock	—	696	52,432
Payments for Shares Withheld for Employee Tax Obligations	(2,942)	(1,507)	(2,069)
Payments for Retirement of Long-Term Debt	—	(169)	(182)
Dividends Paid	(68,755)	(64,864)	(60,314)
Other, net	(461)	(689)	(523)
Net Cash Provided by (Used in) Financing Activities	142,131	(59,977)	93,251
Net Change in Cash and Cash Equivalents	119,243	3	(4,959)
Cash and Cash Equivalents at Beginning of Period	3	—	4,959
Cash and Cash Equivalents at End of Period	\$ 119,246	\$ 3	\$ —

*See accompanying notes to condensed financial statements.*

**OTTER TAIL CORPORATION (PARENT COMPANY)**  
**NOTES TO CONDENSED FINANCIAL STATEMENTS**

**Incorporated by Reference**

OTC's consolidated statements of comprehensive income and common shareholders' equity in Part II, Item 8 are incorporated by reference.

**Basis of Presentation**

The condensed financial information of OTC is presented to comply with Rule 12-04 of Regulation S-X. The unconsolidated condensed financial statements do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read with the consolidated financial statements and related notes included in this report on Form 10-K.

OTC's investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity income in earnings of subsidiaries.

**Related Party Transactions**

Outstanding receivables from and payables to OTC's subsidiaries as of December 31, 2022 and 2021 are as follows:

<i>(in thousands)</i>	<i>Accounts Receivable</i>	<i>Interest Receivable</i>	<i>Current Notes Receivable</i>	<i>Long-Term Notes Receivable</i>	<i>Accounts Payable</i>	<i>Current Notes Payable</i>
<b>December 31, 2022</b>						
Otter Tail Power Company	\$ 3,016	\$ —	\$ —	\$ —	\$ 7	\$ —
Northern Pipe Products, Inc.	—	7	—	5,000	—	77,182
Vinyltech Corporation	—	18	—	11,500	—	90,425
BTD Manufacturing, Inc.	—	77	—	52,000	—	693
T.O. Plastics, Inc.	20	15	—	10,400	—	5,855
Varistar Corporation	—	—	—	—	—	246,208
Otter Tail Assurance Limited	242	—	—	—	—	—
	\$ 3,278	\$ 117	\$ —	\$ 78,900	\$ 7	\$ 420,363
<b>December 31, 2021</b>						
Otter Tail Power Company	\$ 2,503	\$ —	\$ —	\$ —	\$ 7	\$ —
Northern Pipe Products, Inc.	—	7	—	5,000	4	32,057
Vinyltech Corporation	13	18	—	11,500	—	34,881
BTD Manufacturing, Inc.	—	77	6,767	52,000	170	—
T.O. Plastics, Inc.	20	15	—	10,400	—	5,995
Varistar Corporation	—	—	—	—	—	117,271
Otter Tail Assurance Limited	281	—	—	—	—	—
	\$ 2,817	\$ 117	\$ 6,767	\$ 78,900	\$ 181	\$ 190,204

**Dividends**

Dividends paid to OTC (the Parent) from its subsidiaries were as follows:

<i>(in thousands)</i>	<i>2022</i>	<i>2021</i>	<i>2020</i>
Cash Dividends Paid to Parent by Subsidiaries	\$ 68,680	\$ 64,790	\$ 55,614

See OTC's notes to consolidated financial statements in Part II, Item 8 for other disclosures.

**SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES**  
**OTTER TAIL CORPORATION**

Below is a summary of activity within valuation and qualifying accounts for the years ended December 31, 2022, 2021 and 2020:

<i>(in thousands)</i>	<i>Balance, January 1</i>	<i>Charged to Cost and Expenses</i>	<i>Deductions</i> <sup>1, 2</sup>	<i>Balance, December 31</i>
<b>Allowance for Credit Losses</b>				
2022	\$ 1,836	\$ 909	\$ (1,097)	\$ 1,648
2021	3,215	93	(1,472)	1,836
2020	1,339	3,138	(1,262)	3,215
<b>Deferred Tax Asset Valuation Allowance</b>				
2022	\$ —	\$ —	\$ —	\$ —
2021	800	—	(800)	—
2020	800	—	—	800

<sup>1</sup>Amounts under Allowance for Credit Losses reflect deductions to the allowance for amounts written-off, net of recoveries.

<sup>2</sup>Amounts under Deferred Tax Asset Valuation Allowance reflect a release of a valuation allowance based on current expectations of the realizability of the associated deferred tax asset.

### 3. Exhibits

The following Exhibits are filed as part of, or incorporated by reference into, this report.

No.	Description
3.1	<a href="#">Third Restated Articles of Incorporation, dated April 12, 2021.</a>
3.2	<a href="#">Restated Bylaws, dated April 12, 2021.</a>
4.1	<a href="#">Description of Securities</a>
10.1.0	<a href="#">Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.</a>
10.1.1	<a href="#">First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.</a>
10.1.2	<a href="#">Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.</a>
10.1.3	<a href="#">Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007, between Otter Tail Power Company and the Purchasers named therein.</a>
10.2	<a href="#">Note Purchase Agreement dated as of August 14, 2013 between Otter Tail Power Company and the Purchasers named therein.</a>
10.3	<a href="#">Note Purchase Agreement dated as of September 23, 2016 between Otter Tail Corporation and the Purchasers named therein.</a>
10.4	<a href="#">Note Purchase Agreement dated as of November 14, 2017 between Otter Tail Power Company and the Purchasers named therein.</a>
10.5	<a href="#">Note Purchase Agreement dated as of September 12, 2019 between Otter Tail Power Company and the Purchasers named therein.</a>
10.6	<a href="#">Note Purchase Agreement dated as of June 10, 2021 between Otter Tail Power Company and the Purchasers named therein.</a>
10.7	<a href="#">Fifth Amended and Restated Credit Agreement, dated as of October 31, 2022, by and between Otter Tail Corporation, as Borrower, and the banks named therein, with U.S. Bank National Association, as Administrative Agent.</a>
10.8	<a href="#">Fourth Amended and Restated Credit Agreement, dated as of October 31, 2022, by and between Otter Tail Power Company, as Borrower, and the banks named therein, with U.S. Bank Nation Association, as Administration Agent.</a>
10.9.0	Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970). Previously filed as Exhibit 10-F in Form 10-K for the year ended December 31, 1989.
10.9.1	Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984). Previously filed as Exhibit 10-F-1 in Form 10-K for the year ended December 31, 1989.
10.9.2	Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983). Previously filed as Exhibit 10-F-2 in Form 10-K for the year ended December 31, 1991.
10.9.3	Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985). Previously filed as Exhibit 10-F-3 in Form 10-K for the year ended December 31, 1991.
10.9.4	Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986). Previously filed as Exhibit 10-F-4 in Form 10-K for the year ended December 31, 1991.
10.9.5	<a href="#">Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).</a>
10.9.6	Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant. Previously filed as Exhibit 10-F-5 in Form 10-K for the year ended December 31, 1992.
10.10	<a href="#">Big Stone South–Ellendale Project Ownership Agreement dated as of June 12, 2015 between Otter Tail Power Company, a wholly owned subsidiary of Otter Tail Corporation, and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.**</a>
10.11.0	Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company and Minnesota Power & Light Company (dated as of July 1, 1977). Previously filed as Exhibit 5-H in filing 2-61043.
10.11.1	Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1. Previously filed as Exhibit 10-H-1 in Form 10-K for the year ended December 31, 1989.
10.11.2	Supplemental Agreement No. Two, dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement. Previously filed as Exhibit 10-H-2 in Form 10-K for the year ended December 31, 1989.
10.11.3	Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1. Previously filed as Exhibit 10-H-3 in Form 10-K for the year ended December 31, 1989.
10.11.4	Agreement, dated as of September 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No. 1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978. Previously filed as Exhibit 10-H-4 in Form 10-K for the year ended December 31, 1992.
10.11.5	<a href="#">Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.</a>
10.11.6	<a href="#">Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.</a>
10.12.0	<a href="#">Lignite Sales Agreement between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., Northwestern Corporation, dated as of October 10, 2012.**</a>
10.12.1	<a href="#">First Amendment to Lignite Sales Agreement dated as of January 30, 2014 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.</a>
10.12.2	<a href="#">Second Amendment to Lignite Sales Agreement dated as of March 16, 2015 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.</a>
10.13	<a href="#">Wind Energy Purchase Agreement dated May 9, 2013 between Otter Tail Power Company and Ashtabula Wind III, LLC.**</a>

No.	Description
10.14.0	<a href="#">Deferred Compensation Plan for Directors (2003 Restatement).*</a>
10.14.1	<a href="#">First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as Amended.*</a>
10.14.2	<a href="#">Second Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as Amended.*</a>
10.15	<a href="#">Executive Survivor and Supplemental Retirement Plan (2020 Restatement).*</a>
10.16	<a href="#">Nonqualified Retirement Plan (2011 Restatement).*</a>
10.17	<a href="#">1999 Employee Stock Purchase Plan, As Amended (2016).</a>
10.18	<a href="#">1999 Stock Incentive Plan, As Amended (2006).*</a>
10.19	<a href="#">2014 Executive Annual Incentive Plan.*</a>
10.20	<a href="#">Otter Tail Corporation 2014 Stock Incentive Plan.*</a>
10.21	<a href="#">Form of 2015 Restricted Stock Unit Award Agreement (Executives).*</a>
10.22	<a href="#">Form of 2015 Restricted Stock Unit Award Agreement (Legacy).*</a>
10.23	<a href="#">Form of 2015 Restricted Stock Award Agreement for Directors.*</a>
10.24	<a href="#">Otter Tail Corporation Executive Restoration Plus Plan, 2020 Restatement.*</a>
10.25	<a href="#">Form of 2018 Performance Award Agreement (Executives).*</a>
10.26	<a href="#">Form of 2018 Performance Award Agreement (Legacy).*</a>
10.27	<a href="#">Form of 2018 Restricted Stock Award Agreement for Directors.*</a>
10.28	<a href="#">Summary of Non-Employee Director Compensation (2022).*</a>
10.29	<a href="#">Executive Employment Agreement, Kevin Moug, as Amended [effective January 1, 2013].*</a>
10.30	<a href="#">Change in Control Severance Agreement, Kevin G. Moug, dated July 1, 2009.*</a>
10.31	<a href="#">Change in Control Severance Agreement, Chuck MacFarlane, dated February 24, 2012.*</a>
10.32	<a href="#">Change in Control Severance Agreement, Timothy Rogelstad, dated April 14, 2014.*</a>
10.33	<a href="#">Change in Control Severance Agreement, Paul Knutson, dated December 17, 2012.*</a>
10.34	<a href="#">Change in Control Severance Agreement, John Abbott, dated April 13, 2015.*</a>
10.35	<a href="#">Change in Control Severance Agreement, Jennifer Smestad, dated January 1, 2018.*</a>
10.36	<a href="#">Form of Change in Control Severance Agreement (2023)*</a>
10.37	<a href="#">Otter Tail Corporation Executive Severance Plan (2015).*</a>
21	<a href="#">Subsidiaries of Registrant.</a>
23	<a href="#">Consent of Deloitte &amp; Touche LLP.</a>
24	<a href="#">Power of Attorney.</a>
31.1	<a href="#">Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</a>
31.2	<a href="#">Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.</a>
32.1	<a href="#">Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</a>
32.2	<a href="#">Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.</a>
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

\*Management contract, compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.

\*\*Confidential information has been omitted from this Exhibit and filed separately with the Securities and Exchange Commission pursuant to a confidential treatment request under Rule 24b-2.

The Company hereby undertakes to furnish copies of any of the omitted schedules and exhibits to the Securities and Exchange Commission upon request.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

**ITEM 16. FORM 10-K SUMMARY**

None.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OTTER TAIL CORPORATION

By: /s/ Kevin G. Moug

Kevin G. Moug  
Chief Financial Officer and Senior Vice President  
(authorized officer and principal financial officer)

Dated: February 15, 2023

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

### Signature and Title

Charles S. MacFarlane )  
President and Chief Executive Officer )  
(principal executive officer) and Director )

Kevin G. Moug )  
Chief Financial Officer and Senior Vice President )  
(principal financial and accounting officer) )

) By /s/ Charles S. MacFarlane

Nathan I. Partain )  
Chairman of the Board and Director )

Charles S. MacFarlane  
Pro Se and Attorney-in-Fact

Dated: February 15, 2023

Karen M. Bohn, Director )

John D. Erickson, Director )

Steven L. Fritze, Director )

Kathryn O. Johnson, Director )

Michael E. LeBeau, Director )

James B. Stake, Director )

Thomas J. Webb, Director )

Jeanne H. Crain, Director\*\*

Mary E. Ludford, Director\*\*

\*\*Director was appointed to the Otter Tail Corporation Board of Directors effective, January 1, 2023, and has not signed the Annual Report on Form 10-K herein.

## SHAREHOLDER SERVICES

### OTTER TAIL CORPORATION STOCK LISTING

Otter Tail Corporation common stock trades on the Nasdaq Global Select Market. Our ticker symbol is OTTR. You can find our daily stock price on our website, [www.ottertail.com](http://www.ottertail.com). Shareholders who sign up for online account access can view their account information online.

### DIVIDENDS

Otter Tail Corporation has paid dividends on our common shares each quarter since 1938 without interruption or reduction. 2022 dividends were \$1.65 per share, and the year-end dividend yield was 2.8 percent. Total shareholder return grew at a compounded average annual rate of 12.7 percent over the past ten years.

### DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Our Dividend Reinvestment and Share Purchase Plan provides shareowners of record with a convenient method for purchasing shares of Otter Tail Corporation common stock. Approximately 84 percent of eligible shareholders holding approximately 9 percent of our common shares are enrolled. Through this plan, participants may have their dividends automatically reinvested in additional shares without paying any brokerage fees or service charges. Shareholders also may contribute a minimum of \$10 and a maximum of \$120,000 annually to purchase shares of our common stock. Automatic withdrawal from a checking or savings account is available for this service. Shareholders also may sell shares through the plan. Existing Otter Tail shareholders and new investors can enroll online through [shareowneronline.com](http://shareowneronline.com). For the first purchase, the minimum investment is \$250. For more information, contact Shareholder Services.

### ELECTRONIC DIVIDEND DEPOSIT

You can arrange for electronic deposit of your dividends directly to your checking or savings accounts. For authorization materials, contact Shareholder Services.

### STOCK CERTIFICATES AND DIRECT REGISTRATION SYSTEM (DRS)

Replacing missing certificates is a costly and time-consuming process so you should keep a separate record of the certificate number, purchase date, date of issue, price paid, and exact registration name. If you are enrolled in the Dividend Reinvestment and Share Purchase Plan, you have the option of depositing your common certificates into your plan account. We also offer DRS as a method of holding your shares in book-entry form, which eliminates the need to hold stock certificates.

### 2023 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 17, 2023 • 10:30 a.m., Central Daylight Time / Meeting Format: Virtual-only

#### 2023 COMMON DIVIDEND DATES

Ex-Dividend	Record	Payment
February 13	February 14	March 10
May 12	May 15	June 9
August 14	August 15	September 8
November 14	November 15	December 8

#### KEY STATISTICS

Nasdaq	OTTR
Year-end stock price	\$58.71
Year-end market-to-book ratio	2.01
Annual dividend yield	2.8%
Shares outstanding (as of December 31, 2022)	41.6 million
Market capitalization (as of December 31, 2022)	\$2.4 billion
2022 average daily trading volume	160,876
Institutional holdings (shares as of December 31, 2022)	24.2 million

#### TRANSFER AGENT

Equiniti Shareowner Services
P.O. Box 64856, St. Paul, MN 55164-0856
Phone: 800-468-9716 or 651-450-4064

#### 2022 CREDIT RATINGS

	Moody's	Fitch	S&P
<b>Otter Tail Corporation:</b>			
Issuer Default Rating	Baa2	BBB-	BBB
Senior Unsecured Debt	n/a	BBB-	n/a
Outlook	Stable	Stable	Stable

#### Otter Tail Power Company:

Issuer Default Rating	A3	BBB	BBB+
Senior Unsecured Debt	n/a	BBB+	BBB+
Outlook	Stable	Stable	Stable

#### SHAREHOLDER SERVICES

Otter Tail Corporation	Phone: 800-664-1259
215 South Cascade Street	or 218-739-8479
P.O. Box 496	Email: <a href="mailto:sharesvc@ottertail.com">sharesvc@ottertail.com</a>
Fergus Falls, MN 56538-0596	Fax: 218-998-3165



**SHAREHOLDER SERVICES**

215 S. Cascade St., P.O. Box 496

Fergus Falls, MN 56538-0496

Phone: 800-664-1259 or 218-739-8479

Email: [sharesvc@ottetail.com](mailto:sharesvc@ottetail.com)

[www.ottetail.com](http://www.ottetail.com) / Nasdaq: OTTR

THIS FILING IS

Item 1:  An Initial (Original) Submission OR  Resubmission No.



**FERC FINANCIAL REPORT  
FERC FORM No. 1: Annual Report of  
Major Electric Utilities, Licensees  
and Others and Supplemental  
Form 3-Q: Quarterly Financial Report**

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

**Exact Legal Name of Respondent (Company)**

Otter Tail Power Company

**Year/Period of Report**  
End of: 2022/ Q4

FERC FORM NO. 1 (REV. 02-04)

**INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q**

## GENERAL INFORMATION

### I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

### II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

### III. What and Where to Submit

- Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at <https://eCollection.ferc.gov>, and according to the specifications in the Form 1 and 3-Q taxonomies.
- The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.
- Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:  
Secretary  
Federal Energy Regulatory Commission 888 First Street, NE  
Washington, DC 20426
- For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

- The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.
- Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <https://www.ferc.gov/general-information/0/electric-industry-forms>.

### IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

- FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

### V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

## GENERAL INSTRUCTIONS

- Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USoFA). Interpret all accounting words and phrases in accordance with the USoFA.
- Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are indicated. The fraction of cents is allowed except on the four basic

- For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).
- Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.
- Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.
- Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

### DEFINITIONS

- Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.
- Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

## EXCERPTS FROM THE LAW

### Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit:

- 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
- 'Person' means an individual or a corporation;
- 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
- 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....
- 'project' means, a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

- To make investigations and to collect and record data concerning the utilization of the water resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

- Every Licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies".<sup>10</sup>

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

FERC FORM NO. 1 (ED 03-07)  
Financial statements are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

## GENERAL PENALTIES

The Commission may assess up to \$1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

**FERC FORM NO. 1  
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

**IDENTIFICATION**

01 Exact Legal Name of Respondent Otter Tail Power Company		02 Year/ Period of Report End of: 2022/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 215 South Cascade Street, PO Box 496, Fergus Falls, MN 56538-0496		
05 Name of Contact Person Janelle Johnson		06 Title of Contact Person Controller, Utility
07 Address of Contact Person (Street, City, State, Zip Code) 215 South Cascade Street, PO Box 496 Fergus Falls, MN 56538-0496		
08 Telephone of Contact Person, Including Area Code 218-739-8758	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2022
<b>Annual Corporate Officer Certification</b>		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Todd Wahlund	03 Signature Todd Wahlund	04 Date Signed (Mo, Da, Yr) 04/14/2023
02 Title Chief Financial Officer		
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**LIST OF SCHEDULES (Electric Utility)**

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	<a href="#">1</a>	
	List of Schedules	<a href="#">2</a>	
1	General Information	<a href="#">101</a>	
2	Control Over Respondent	<a href="#">102</a>	
3	Corporations Controlled by Respondent	<a href="#">103</a>	Not Applicable
4	Officers	<a href="#">104</a>	
5	Directors	<a href="#">105</a>	
6	Information on Formula Rates	<a href="#">106</a>	106(b) Not Applicable
7	Important Changes During the Year	<a href="#">108</a>	
8	Comparative Balance Sheet	<a href="#">110</a>	
9	Statement of Income for the Year	<a href="#">114</a>	
10	Statement of Retained Earnings for the Year	<a href="#">118</a>	
12	Statement of Cash Flows	<a href="#">120</a>	
12	Notes to Financial Statements	<a href="#">122</a>	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	<a href="#">122a</a>	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	<a href="#">200</a>	
15	Nuclear Fuel Materials	<a href="#">202</a>	Not Applicable
16	Electric Plant in Service	<a href="#">204</a>	
17	Electric Plant Leased to Others	<a href="#">213</a>	Not Applicable
18	Electric Plant Held for Future Use	<a href="#">214</a>	
19	Construction Work in Progress-Electric	<a href="#">216</a>	
20	Accumulated Provision for Depreciation of Electric Utility Plant	<a href="#">219</a>	
21	Investment of Subsidiary Companies	<a href="#">224</a>	Not Applicable
22	Materials and Supplies	<a href="#">227</a>	
23	Allowances	<a href="#">228</a>	
24	Extraordinary Property Losses	<a href="#">230a</a>	Not Applicable
25	Unrecovered Plant and Regulatory Study Costs	<a href="#">230b</a>	
26	Transmission Service and Generation Interconnection Study Costs	<a href="#">231</a>	
27	Other Regulatory Assets	<a href="#">232</a>	
28	Miscellaneous Deferred Debits	<a href="#">233</a>	
29	Accumulated Deferred Income Taxes	<a href="#">234</a>	
30	Capital Stock	<a href="#">250</a>	
31	Other Paid-in Capital	<a href="#">253</a>	
32	Capital Stock Expense	<a href="#">254b</a>	Not Applicable
33	Long-Term Debt	<a href="#">256</a>	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	<a href="#">261</a>	
35	Taxes Accrued, Prepaid and Charged During the Year	<a href="#">262</a>	
36	Accumulated Deferred Investment Tax Credits	<a href="#">266</a>	
37	Other Deferred Credits	<a href="#">269</a>	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	<a href="#">272</a>	
39	Accumulated Deferred Income Taxes-Other Property	<a href="#">274</a>	
40	Accumulated Deferred Income Taxes-Other	<a href="#">276</a>	
41	Other Regulatory Liabilities	<a href="#">278</a>	
42	Electric Operating Revenues	<a href="#">300</a>	
43	Regional Transmission Service Revenues (Account 457.1)	<a href="#">302</a>	Not Applicable
44	Sales of Electricity by Rate Schedules	<a href="#">304</a>	
45	Sales for Resale	<a href="#">310</a>	
46	Electric Operation and Maintenance Expenses	<a href="#">320</a>	

47	Purchased Power	<a href="#">326</a>	
48	Transmission of Electricity for Others	<a href="#">328</a>	
49	Transmission of Electricity by ISO/RTOs	<a href="#">331</a>	Not Applicable
50	Transmission of Electricity by Others	<a href="#">332</a>	
51	Miscellaneous General Expenses-Electric	<a href="#">335</a>	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	<a href="#">336</a>	
53	Regulatory Commission Expenses	<a href="#">350</a>	
54	Research, Development and Demonstration Activities	<a href="#">352</a>	
55	Distribution of Salaries and Wages	<a href="#">354</a>	
56	Common Utility Plant and Expenses	<a href="#">356</a>	Not Applicable
57	Amounts included in ISO/RTO Settlement Statements	<a href="#">397</a>	
58	Purchase and Sale of Ancillary Services	<a href="#">398</a>	
59	Monthly Transmission System Peak Load	<a href="#">400</a>	
60	Monthly ISO/RTO Transmission System Peak Load	<a href="#">400a</a>	Not Applicable
61	Electric Energy Account	<a href="#">401a</a>	
62	Monthly Peaks and Output	<a href="#">401b</a>	
63	Steam Electric Generating Plant Statistics	<a href="#">402</a>	
64	Hydroelectric Generating Plant Statistics	<a href="#">406</a>	Not Applicable
65	Pumped Storage Generating Plant Statistics	<a href="#">408</a>	Not Applicable
66	Generating Plant Statistics Pages	<a href="#">410</a>	
0	Energy Storage Operations (Large Plants)	<a href="#">414</a>	Not Applicable
67	Transmission Line Statistics Pages	<a href="#">422</a>	
68	Transmission Lines Added During Year	<a href="#">424</a>	
69	Substations	<a href="#">426</a>	
70	Transactions with Associated (Affiliated) Companies	<a href="#">429</a>	
71	Footnote Data	<a href="#">450</a>	
	<b>Stockholders' Reports (check appropriate box)</b>		
	Stockholders' Reports Check appropriate box:  <input type="checkbox"/> Two copies will be submitted <input checked="" type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
<b>GENERAL INFORMATION</b>			
1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.  Janelle Johnson Controller, Utility			
2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.  State of Incorporation: MN Date of Incorporation: 1907-07-05 Incorporated Under Special Law:			
3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.  (a) Name of Receiver or Trustee Holding Property of the Respondent: (b) Date Receiver took Possession of Respondent Property: (c) Authority by which the Receivership or Trusteeship was created: (d) Date when possession by receiver or trustee ceased:			
4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.  Minnesota - Electric North Dakota - Electric South Dakota - Electric			
5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements? (1) <input type="checkbox"/> Yes (2) <input checked="" type="checkbox"/> No			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
<b>CONTROL OVER RESPONDENT</b>			
1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.			
Otter Tail Corporation, a registered holding company, owns all of the common stock of the respondent.			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**CORPORATIONS CONTROLLED BY RESPONDENT**

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Not applicable.			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**OFFICERS**

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.  
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Chief Executive Officer, Utility *	Charles S. MacFarlane			
2	President, Utility	Timothy J. Rogelstad			
3	Vice President, Customer Service	Steve J. Schoeneck			
4	Chief Financial Officer	Todd R. Wahlund			
5	Vice President, Regulatory Affairs	Bruce G. Gerhardson			
6	General Counsel & Vice President, Legal Affairs *	Jennifer O. Smestad			
7	Vice President, Asset Management	JoAnn M. Thompson			
8	Vice President, Energy Supply	Bradley E. Tollerson			
9	Director, Human Resources & Safety	Peter E. Wasberg			
10	Vice President, Information Technology *	Don L. Redden			
11	Director, Public Relations	Stephanie A. Hoff			
12	Treasurer *	Kevin G. Moug			
13	Assistant Treasurer *	Andrew C. Miller			
14	* This individual is an employee of Otter Tail Corporation				
15	and a portion of their salary is allocated to the				
16	respondent. The reported amount is prorated to the				
17	utility.				

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**DIRECTORS**

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.  
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Charles MacFarlane, Director, Chief Executive Officer	Fergus Falls, Minnesota	false	false
2	Kevin Moug, Director	Fargo, North Dakota	false	false
3	Timothy Rogelstad, Director, President	Fergus Falls, Minnesota	false	false
4	John Abbott, Director	Fargo, North Dakota	false	false
5	Jennifer Smestad, Director	Fergus Falls, Minnesota	false	false

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**INFORMATION ON FORMULA RATES**

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	MISO FERC Electric Tariff Original Vol. No. 1	ER98-1438-000
2	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER04-895-000
3	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER05-122-000
4	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER04-458-008
5	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-18-000
6	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-159-000
7	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER09-91-000
8	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1657-000
9	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1779-000
10	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-183
11	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-686
12	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1492-000
13	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1791
14	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER10-1997-000;001
15	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-28-000;001
16	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3279-000
17	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3704-000
18	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-297-000
19	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-312-000
20	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-334-000
21	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-450-000
22	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-715-000;002
23	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-1667-000
24	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-263-001
25	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-674-000;002
26	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-1169-000
27	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-1169-001
28	MISO FERC Electric Tariff	ER12-480-006;007
29	MISO FERC Electric Tariff	ER13-2379-000;003;004
30	MISO FERC Electric Tariff	ER14-260-000
31	MISO FERC Electric Tariff	ER14-261-000
32	MISO FERC Electric Tariff	ER14-421-000;001
33	MISO FERC Electric Tariff	ER15-358
34	MISO FERC Electric Tariff	ER15-1490
35	MISO FERC Electric Tariff	ER16-1313
36	MISO FERC Electric Tariff	ER16-1534
37	MISO FERC Electric Tariff	ER16-392
38	MISO FERC Electric Tariff	ER16-197
39	MISO FERC Electric Tariff	ER17-1014
40	MISO FERC Electric Tariff	ER17-1393
41	MISO FERC Electric Tariff	ER18-867
42	MISO FERC Electric Tariff	ER18-1982
43	MISO FERC Electric Tariff	ER18-1159-000
44	MISO FERC Electric Tariff	ER19-249-000
45	MISO FERC Electric Tariff	ER19-652-000
46	MISO FERC Electric Tariff	ER19-2050-000; 002

47	MISO FERC Electric Tariff	ER20-175-000
48	MISO FERC Electric Tariff	ER20-176-000
49	MISO FERC Electric Tariff	ER20-1167-000
50	MISO FERC Electric Tariff	ER21-1563-000
51	MISO FERC Electric Tariff	ER21-200-000
52	MISO FERC Electric Tariff	ER21-262-000
53	MISO FERC Electric Tariff	ER22-90-000
54	MISO FERC Electric Tariff	ER22-1579

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding**

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20190315-5163	03/15/2019	ER19-1336	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff
2	20200313-5137	03/13/2020	ER20-1278	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff
3	20210315-5306	03/15/2021	ER21-1418	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff
4	20220315-5246	03/15/2022	ER22-1348	Attachment O; Annual Informational Filing	MISO FERC Electric Tariff

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**INFORMATION ON FORMULA RATES - Formula Rate Variances**

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
<b>IMPORTANT CHANGES DURING THE QUARTER/YEAR</b>			
Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.			
<ol style="list-style-type: none"> <li>1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.</li> <li>2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.</li> <li>3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.</li> <li>4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.</li> <li>5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.</li> <li>6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.</li> <li>7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.</li> <li>8. State the estimated annual effect and nature of any important wage scale changes during the year.</li> <li>9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.</li> <li>10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.</li> <li>11. (Reserved.)</li> <li>12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.</li> <li>13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.</li> <li>14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.</li> </ol>			
None.			
None.			
None.			
None.			
None.			
See Note 9 in the Notes to Financial Statements and the Capital Resources Section of Otter Tail Corporation's 2022 10-Q filing with the Securities Exchange Commission (SEC).			
None.			
Local unions 203, 239, 524, and 949 was increased 3% effective 11.1.22.			
See Item 1, Legal Proceedings in Part II of Otter Tail Corporation's 2022 10-Q filing with the Securities Exchange Commission (SEC).			
None.			
None.			
None.			
Not Applicable.			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)**

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	<b>UTILITY PLANT</b>			
2	Utility Plant (101-106, 114)	200	2,851,416,666	2,766,025,349
3	Construction Work in Progress (107)	200	118,374,711	76,740,501
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,969,791,377	2,842,765,850
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	985,407,109	936,736,791
6	Net Utility Plant (Enter Total of line 4 less 5)		1,984,384,268	1,906,029,059
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,984,384,268	1,906,029,059
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	<b>OTHER PROPERTY AND INVESTMENTS</b>			
18	Nonutility Property (121)		269,036	269,036
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		30,227	28,653
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		8,068,151	2,529,924
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		8,367,414	2,827,613
33	<b>CURRENT AND ACCRUED ASSETS</b>			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		6,533	2,300
36	Special Deposits (132-134)		7,005,266	73,223
37	Working Fund (135)		11,463	12,483
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		25,432,510	22,180,796
41	Other Accounts Receivable (143)		9,443,705	9,506,901
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,249,454	1,589,042
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		6,853	9,787
45	Fuel Stock (151)	227	11,000,592	9,708,604
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	32,716,145	25,534,425
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		

52	Allowances (158.1 and 158.2)	228	\$111,884	100,962
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		\$2,683,983	2,534,709
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		23,871,752	23,842,673
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)			6,213,576
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		111,041,232	98,131,397
68	<b>DEFERRED DEBITS</b>			
69	Unamortized Debt Expenses (181)		3,593,164	3,680,816
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	1,310,240	3,590,780
72	Other Regulatory Assets (182.3)	232	127,348,666	156,156,750
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		172,376	34,519
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233		322,303
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		240,317	340,554
82	Accumulated Deferred Income Taxes (190)	234	122,236,993	96,331,014
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		254,901,756	260,456,736
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,358,694,670	2,267,444,805

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: ConstructionWorkInProgress

Per its FERC-approved tariff, the Company uses a 13-month average of CWIP for rate-making purposes, illustrated as follows for the current year:

	CWIP
December 31, 2021	76,740,501
January 31, 2022	80,444,221
February 28, 2022	71,880,246
March 31, 2022	74,669,450
April 30, 2022	81,789,285
May 31, 2022	95,345,694
June 30, 2022	98,960,969
July 31, 2022	107,248,690
August 31, 2022	123,397,451
September 30, 2022	133,405,265
October 31, 2022	139,653,084
November 30, 2022	141,633,092
December 31, 2022	118,374,711
13-month average for rate-making	103,349,435

(b) Concept: AccumulatedProvisionForUncollectibleAccountsCredit

As of December 31, 2022, total allowance for credit losses includes an amount of -\$60,272 for provisions for uncollectible accounts related to unbilled revenue estimates which is included in FERC account 173.

	December 31, 2022	December 31, 2021
Accum Prov. for Uncollectible Accts (FERC 144)	(1,249,454)	(1,589,042)
Estimated losses as a reduction of Unbilled Revenue included in FERC acct 173	(60,272)	(58,228)
Total Allowance for Credit Losses	(1,309,726)	(1,647,270)

(c) Concept: FuelStock

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Fuel Stock
December 31, 2021	9,708,604
January 31, 2022	9,523,141
February 28, 2022	9,657,742
March 31, 2022	9,222,089
April 30, 2022	10,859,822
May 31, 2022	11,851,251
June 30, 2022	10,513,083
July 31, 2022	9,204,492
August 31, 2022	8,370,592
September 30, 2022	8,546,971
October 31, 2022	9,277,920
November 30, 2022	10,316,127
December 31, 2022	11,000,592
13-month average for rate-making	9,850,187

(d) Concept: AllowanceInventoryAndWithheld

Renewable Energy Credits and emissions allowances are held in the allowance inventory account (158.1) for future use.

Solar REC Emission Allowance Inventory	90,766
Co-Gen REC Emission Allowance Inventory	21,118
	111,884

(e) Concept: Prepayments

Per its FERC-approved tariff, the Company uses a 13 month average of allowable prepaid expenses for rate-making purposes, illustrated as follows for the current year:

December 31, 2021	2,534,709
January 31, 2022	4,551,318
February 28, 2022	4,664,036
March 31, 2022	3,742,667
April 30, 2022	5,984,710
May 31, 2022	6,572,415
June 30, 2022	5,613,107
July 31, 2022	4,653,783
August 31, 2022	4,912,286
September 30, 2022	4,410,691
October 31, 2022	3,591,533
November 30, 2022	2,656,314
December 31, 2022	2,683,983
13-month average for rate-making	4,351,658

Name of Respondent: Otter Tail Power Company		This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
<b>COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)</b>				
Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	<b>PROPRIETARY CAPITAL</b>			
2	Common Stock Issued (201)	250	500	500
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	636,988,966	586,988,966
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	273,527,850	248,498,059
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(1,086,005)	(2,798,909)
16	Total Proprietary Capital (lines 2 through 15)		909,431,311	832,688,616
17	<b>LONG-TERM DEBT</b>			
18	Bonds (221)	256	747,000,000	687,000,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)			
24	Total Long-Term Debt (lines 18 through 23)		747,000,000	687,000,000
25	<b>OTHER NONCURRENT LIABILITIES</b>			
26	Obligations Under Capital Leases - Noncurrent (227)			
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		680,181	629,292
29	Accumulated Provision for Pensions and Benefits (228.3)		65,191,975	117,876,991
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		1,843,265	12,680,553
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		25,182,260	24,190,703
35	Total Other Noncurrent Liabilities (lines 26 through 34)		92,897,681	155,377,539
36	<b>CURRENT AND ACCRUED LIABILITIES</b>			
37	Notes Payable (231)		8,203,643	68,525,649
38	Accounts Payable (232)		73,752,876	62,872,113
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		3,016,333	2,503,324
41	Customer Deposits (235)		575,926	692,666
42	Taxes Accrued (236)	262	17,375,004	16,969,565
43	Interest Accrued (237)		8,989,895	9,332,232
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		1,733,300	1,820,492
48	Miscellaneous Current and Accrued Liabilities (242)		411,943	17,849
49	Obligations Under Capital Leases-Current (243)			
50	Derivative Instrument Liabilities (244)		7,130,408	

51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		121,189,328	162,733,890
55	<b>DEFERRED CREDITS</b>			
56	Customer Advances for Construction (252)		4,477,091	3,081,475
57	Accumulated Deferred Investment Tax Credits (255)	266	15,916,108	16,660,631
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	2,648,845	1,968,728
60	Other Regulatory Liabilities (254)	278	147,555,795	149,372,689
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	10,629,721	8,408,032
63	Accum. Deferred Income Taxes-Other Property (282)		279,386,187	221,367,931
64	Accum. Deferred Income Taxes-Other (283)		27,562,603	28,785,274
65	Total Deferred Credits (lines 56 through 64)		488,176,350	429,644,760
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,358,694,670	2,267,444,805

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**STATEMENT OF INCOME**

- Quarterly
- Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
  - Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
  - Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
  - Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
  - If additional columns are needed, place them in a footnote.

- Annual or Quarterly if applicable
- Do not report fourth quarter data in columns (e) and (f)
  - Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
  - Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
  - Use page 122 for important notes regarding the statement of income for any account thereof.
  - Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
  - Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
  - If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
  - Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
  - Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
  - If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	545,474,498	476,056,453			545,474,498	476,056,453				
3	Operating Expenses											
4	Operation Expenses (401)	320	305,363,870	253,987,526			305,363,870	253,987,526				
5	Maintenance Expenses (402)	320	36,636,350	31,266,440			36,636,350	31,266,440				
6	Depreciation Expense (403)	336	64,650,111	66,407,911			64,650,111	66,407,911				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	521,899	623,451			521,899	623,451				
8	Amort. & Depl. of Utility Plant (404-405)	336	3,561,857	3,421,713			3,561,857	3,421,713				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		181,383	290,654			181,383	290,654				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		608,439	639,397			608,439	639,397				
13	(Less) Regulatory Credits (407.4)		(580,430)	3,880,456			(580,430)	3,880,456				
14	Taxes Other Than Income Taxes (408.1)	262	17,733,835	17,601,364			17,733,835	17,601,364				
15	Income Taxes - Federal (409.1)	262	(22,875,139)	(1,113,903)			(22,875,139)	(1,113,903)				
16	Income Taxes - Other (409.1)	262	(4,004,146)	(999,089)			(4,004,146)	(999,089)				
17	Provision for Deferred Income Taxes (410.1)	234, 272	13,857,976	24,932,156			13,857,976	24,932,156				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	(18,167,109)	20,922,204			(18,167,109)	20,922,204				
19	Investment Tax Credit Adj. - Net (411.4)	266	(744,523)	(744,517)			(744,523)	(744,517)				
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		10	8			10	8				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		991,557	937,973			991,557	937,973				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		435,230,998	372,448,408			435,230,998	372,448,408				



66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)											
68	Other Interest Expense (431)		748,790	1,160,625								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		930,087	629,160								
70	Net Interest Charges (Total of lines 62 thru 69)		31,949,998	33,043,300								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		79,974,186	72,457,845								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		79,974,186	72,457,845								

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**STATEMENT OF RETAINED EARNINGS**

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		247,581,325	227,091,178
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		79,974,186	72,457,845
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Excess hydro licensing amortization		(204,807)	(135,409)
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(204,807)	(135,409)
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1			(54,944,395)	(51,832,289)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(54,944,395)	(51,832,289)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		272,406,309	247,581,325
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		1,121,541	916,734
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,121,541	916,734
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		273,527,850	248,498,059
	UNAPPROPRIATED UNDISTRICTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

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**STATEMENT OF CASH FLOWS**

- Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
- Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
- Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
- Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	79,974,186	72,457,845
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	65,172,010	67,031,362
5	Amortization of (Specify) (footnote details)		
5.1	<sup>(a)</sup> Amortization	3,936,266	3,884,639
5.2	Vehicle depreciation allocated to various operating accounts	2,342,895	2,155,474
8	Deferred Income Taxes (Net)	33,111,295	13,833,524
9	Investment Tax Credit Adjustment (Net)	(744,523)	(744,516)
10	Net (Increase) Decrease in Receivables	(3,525,171)	(3,500,525)
11	Net (Increase) Decrease in Inventory	(8,484,629)	(4,417,237)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	19,433,230	2,653,107
14	Net (Increase) Decrease in Other Regulatory Assets	28,808,084	27,883,459
15	Net Increase (Decrease) in Other Regulatory Liabilities	(1,816,894)	(2,556,099)
16	(Less) Allowance for Other Funds Used During Construction	1,690,320	821,516
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	<sup>(b)</sup> Other: (increase) decrease in noncurrent assets and deferred debits	(2,974,578)	(922,721)
18.2	<sup>(b)</sup> Other: increase (decrease) in noncurrent liabilities and deferred cost	(60,086,837)	(26,393,480)
18.3	<sup>(c)</sup> Other: (increase) decrease in other current assets	6,035,222	(9,808,251)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	159,490,236	140,735,065
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(149,431,971)	(116,868,921)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		1
30	(Less) Allowance for Other Funds Used During Construction	(1,690,320)	(821,516)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(147,741,651)	(116,047,404)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		

51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	560,931	(22,188,852)
53	Other (provide details in footnote):		
53.1	<sup>(a)</sup> Other: (increase) decrease in funds on deposit with trustee	(6,932,043)	12
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(154,112,763)	(138,236,244)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	90,000,000	140,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	<sup>(a)</sup> Other: debt issuance expense	(286,756)	(1,416,171)
66	Net Increase in Short-Term Debt (c)		52,694,878
67	Other (provide details in footnote):		
67.1	<sup>(a)</sup> Other: change in checks written in excess of cash	178,897	(1,945,239)
67.2	<sup>(a)</sup> Other: proceeds from capital infusions	50,000,000	
70	Cash Provided by Outside Sources (Total 61 thru 69)	139,892,141	189,333,468
72	Payments for Retirement of:		
73	Long-term Debt (b)	(30,000,000)	(140,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Bond Issuance Costs		
78	Net Decrease in Short-Term Debt (c)	(60,322,006)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(54,944,395)	(51,832,289)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(5,374,260)	(2,498,821)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	3,213	
88	Cash and Cash Equivalents at Beginning of Period	14,783	14,783
90	Cash and Cash Equivalents at End of Period	17,996	14,783

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

<p>(a) Concept: NoncashAdjustmentsToCashFlowsFromOperatingActivitiesDescription Amortization of intangible plant, plant acquisition adjustments and deferred costs, and debt discount and expense.</p>
<p>(b) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription Changes in miscellaneous deferred debits.</p>
<p>(c) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription Includes changes in: other investments, other special funds, clearing accounts, miscellaneous deferred credits, and unamortized loss on reacquired debt.</p>
<p>(d) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription Includes changes in: notes receivable, prepayments, interest and dividends receivable, accrued utility revenues, miscellaneous current and accrued assets.</p>
<p>(e) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivitiesDescription Change in special funds on deposit with fiscal agent.</p>
<p>(f) Concept: OtherAdjustmentsToCashFlowsFromFinancingActivitiesDescription Debt issuance expense.</p>
<p>(g) Concept: DescriptionForOtherAdjustmentsByOutsideSourcesToCashFlowsFromFinancingActivities Change in checks written in excess of cash.</p>
<p>(h) Concept: DescriptionForOtherAdjustmentsByOutsideSourcesToCashFlowsFromFinancingActivities Proceeds from capital infusions from parent company.</p>

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK  
SEE PAGE 123 FOR REQUIRED INFORMATION.

## 1. Summary of Significant Accounting Policies

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 more than 130,000 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. While our customer base includes relatively few large customers, sales to commercial and industrial customers are significant, with one industrial customer accounting for 11% and 10% of operating revenues for the years ended December 31, 2022 and 2021.

In addition to 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.

### Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and this report differs from Generally Accepted Accounting Principles (GAAP). The significant differences consist of the following:

- Earnings per share, as determined under GAAP, are not reported herein
- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Various revenues and expenses are presented as other income and income deductions for FERC presentation and reported as operating income and expenses for the GAAP presentation.
- Revenue is classified in the Income Statement as Operating Revenue based on FERC account, while GAAP presentation reflects revenue as either revenue from contract with customers or alternative revenue programs.
- A portion of the non-service benefit costs are capitalized and included in rate base additions for rate recovery for regulatory treatment, while GAAP presentation reflects these costs as non-operating expenses.
- No operating lease assets or liabilities are recognized under FERC. An operating lease right-of-use asset and lease liability are recognized for most operating leases under GAAP.
- Capitalized cloud computing costs are reported in FERC accounts for utility plant, while GAAP presentation reflects these costs as other noncurrent assets.

### 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 sheet and included in the statements of comprehensive income as an expense or income 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.

Reconciliation of Cash and Cash Equivalents (Lines 88 and 90 on Page 121) with Balance Sheet Accounts (Page 110): Account 136 – Temporary Cash Investment (Line 38, Page 110), contains amounts which are considered cash equivalents:

	<i>December 31, 2022</i>	<i>December 31, 2021</i>
Cash - Account 131 (line 35, Page 110)	\$ 6,533	\$ 2,300
Working Fund - Account 135 (Line 37, Page 110)	11,463	12,483
<b>Cash Equivalents</b>	<b>\$ 17,996</b>	<b>\$ 14,783</b>

### Revenue Recognition

Customer electricity use is metered, and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment, under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is recognized for fuel and purchased power costs incurred but not yet billed through the fuel clause adjustment, for conservation program incentives and bonuses earned but not yet billed and for renewable resource, transmission-related and environmental incurred costs and investment returns approved for recovery through riders.

Revenues on wholesale electricity sales from company-owned generating units are recognized when energy is delivered. For shared use of transmission facilities with certain regional transmission cooperatives, revenues are estimated. Bills are rendered based on anticipated usage and settlements are made later based on actual usage. Estimated revenues may be adjusted prior to settlement, or at the time of settlement, to reflect actual usage.

### 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, which consist of fuel, materials and supplies, are valued at the lower of cost, determined on an average cost basis, or net realizable value.

### Property, Plant and Equipment

Electric plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized to electric plant was \$0.9 million in 2022 and \$0.6 million in 2021. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Removal costs, when incurred, are charged against the regulatory liability. Maintenance, repairs and replacement of minor items are charged to operating expenses as incurred. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

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

<i>(years)</i>	<i>Service Life Range</i>	
	<i>Low</i>	<i>High</i>
Electric Assets:		
Production Plant	13	113
Transmission Plant	51	75
Distribution Plant	16	70
General Plant	5	60

### 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 five 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 investment.

#### **Recoverability of Long-Lived Assets**

We review our long-lived assets, including, among other assets, property, plant and equipment, 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.

#### **Employee Benefit Plans**

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.

#### **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 adjustment 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 apply the deferral method of accounting for investment tax credits (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.

#### **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 by 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 sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (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 \$45 million, our 35% share of CCMC's unrecovered costs as of December 31, 2022, if recovery of such a loss is denied by regulatory authorities.

#### Subsequent Events

We have considered events for recognition or disclosure in the financial statements that occurred subsequent to December 31, 2022 through March 9, 2023, the date the GAAP financial statements were available for issuance, and through April 14, 2023 for all circumstances that would require disclosure. Management is not aware of any material subsequent events that would require recognition or disclosure in the 2022 financial statements.

## 2. Receivables

Receivables as of December 31, 2022 and 2021 are as follows:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
Receivables		
Trade	\$ 25,439	\$ 22,188
Other	9,444	9,509
Unbilled Receivables	23,932	23,901
Total Receivables	58,815	55,598
Less Allowance for Credit Losses	1,310	1,647
<b>Receivables, net of allowance for credit losses</b>	<b>\$ 57,505</b>	<b>\$ 53,951</b>

The following is a summary of activity in the allowance for credit losses for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
<b>Beginning Balance, January 1</b>	<b>\$ 1,647</b>	<b>\$ 3,053</b>
Additions Charged to Expense	760	66
Reductions for Amounts Written-Off, Net of Recoveries	(1,097)	(1,472)
<b>Ending Balance, December 31</b>	<b>\$ 1,310</b>	<b>\$ 1,647</b>

### 3. Regulatory Matters

#### Regulatory Assets and Liabilities

The following presents our current and long-term regulatory assets and liabilities as of December 31, 2022 and 2021 and the period we expect to recover or refund such amounts:

<i>(in thousands)</i>	<i>Period of Recovery/Refund</i>	<i>December 31, 2022</i>	<i>December 31, 2021</i>
<b>Regulatory Assets</b>			
Asset Retirement Obligations <sup>1</sup>	Asset lives	\$ 11,590	\$ 10,077
Pension and Other Postretirement Benefit Plans <sup>1</sup>	Up to 1 year	87,528	120,728
Revenue Recovery Riders	Up to 2 years	8,186	17,453
ISO Cost Recovery Trackers <sup>1</sup>	Up to 2 years	890	1,342
Deferred Rate Case Expenses <sup>1</sup>	Up to 2 years	1,131	1,738
Fuel Clause Adjustment <sup>1</sup>	Up to 1 year	10,893	4,819
Derivative Instruments	Up to 1 year	7,130	—
<b>Total Regulatory Assets</b>		<b>\$ 127,349</b>	<b>\$ 156,157</b>
<b>Regulatory Liabilities</b>			
Deferred Income Taxes	Asset lives	\$ 131,480	\$ 129,437
Pension and Other Postretirement Benefit Plans	Up to 1 year	5,590	2,603
Fuel Clause Adjustment	Up to 1 year	365	1,554
Revenue Recovery Riders	Various	9,967	9,108
ISO Cost Recovery Trackers	Up to 2 years	15	348
Derivative Instruments	Up to 1 year	—	6,214
Other	Various	139	109
<b>Total Regulatory Liabilities</b>		<b>\$ 147,556</b>	<b>\$ 149,373</b>

<sup>1</sup>Costs subject to recovery without a 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 subject to refund, respectively, primarily due to investments in qualifying transmission, conservation, renewable resource, environmental and other generation assets, and the impact of decoupling.

**Asset Retirement Obligations** represent the difference in timing of recognition of expense arising from these obligations and the amount recovered from customers.

**Independent System Operator (ISO) Cost Recovery Trackers** represent costs incurred to serve Minnesota customers for the under-collection of revenue based on expected versus actual construction costs on eligible projects.

**Deferred Rate Case Expenses** relate to costs incurred in conjunction with recent rate cases that are currently being recovered, or are expected to be recovered, from customers.

**Fuel Clause Adjustments** represent the under- or over-collection of fuel costs to be collected from or returned to customers.

**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.

**Derivative Instruments** represent unrealized gains and losses recognized on derivative instruments. On final settlement of such instruments, any realized gains or losses are paid to or recovered from customers.

#### Minnesota Rate Case

On November 2, 2020, we filed an initial request with the MPUC for an increase in revenue recoverable through base rates in Minnesota, and on December 3, 2020, the MPUC approved an interim annual rate increase of \$6.9 million, or 3.2%, effective January 1, 2021.

On February 1, 2022, the MPUC issued its written order on final rates. The key provisions of the order included a revenue requirement of \$209.0 million, based on a return on rate base of 7.18% and an allowed ROE of 9.48% on an equity ratio of 52.5%. The order also authorized recovery of our remaining Hoot Lake Plant net asset over a five-year period and approved the requested decoupling mechanism for most residential and commercial customer rate groups with a cap of 4% of annual base revenues.

On May 12, 2022, our final rate case compliance filing was approved by the MPUC. The filing included final revenue calculations, rate design and resulting tariff revisions, along with a determination of the interim rate refund, which resulted in an increase in revenues during 2022 of \$4.1 million. Final rates took effect on July 1, 2022, and interim rate refunds of \$15.3 million were applied to customer accounts.

**MISO Resource Planning Auction**

In 2022, we offered excess capacity into the annual MISO planning resource auction for the period June 2022 through May 2023. As a result of a capacity shortage in the MISO region, capacity prices cleared the auction at maximum pricing. During the year ended December 31, 2022, we recorded approximately \$5.3 million of excess capacity auction revenues. We anticipate the Minnesota allocated portion of net capacity auction revenues will be returned to customers through the FCA mechanism in the state, and a portion of the net capacity auction revenues allocated to our other jurisdictions will be used to mitigate customer rate increases or returned to customers through various mechanisms. As of December 31, 2022, we had recognized a reduction of a regulatory asset of \$2.6 million and a refund liability of \$1.8 million for net capacity auction revenues we anticipate will be refunded to customers.

**4. Electric Plant**

Major classes of electric plant as of December 31, 2022 and 2021 include:

<i>(in thousands)</i>	<i>December 31, 2022</i>		<i>December 31, 2021</i>	
<b>Electric Plant in Service</b>				
Electric Plant in Service	\$	2,851,417	\$	2,766,025
Construction Work in Progress		118,375		76,741
Total Gross Electric Plant		2,969,791		2,842,766
Less Accumulated Depreciation and Amortization		985,407		936,737
<b>Net Electric Plant</b>	<b>\$</b>	<b>1,984,384</b>	<b>\$</b>	<b>1,906,029</b>

Depreciation expense for the years ended December 31, 2022 and 2021 totaled \$67.5 million and \$69.1 million.

The following table provides our ownership percentages and amounts included in the December 31, 2022 and 2021 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>
<b>December 31, 2022</b>					
Big Stone Plant	53.9 %	\$ 338,411	\$ 557	\$ (118,044)	\$ 220,924
Coyote Station	35.0 %	183,461	2,315	(111,666)	74,110
Big Stone South–Ellendale 345 kV line	50.0 %	106,185	—	(5,587)	100,598
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(10,095)	68,089
Big Stone South–Brookings 345 kV line	50.0 %	53,041	—	(4,406)	48,635
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,291	—	(3,211)	23,080
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(3,318)	13,013
<b>December 31, 2021</b>					
Big Stone Plant	53.9 %	\$ 338,699	\$ 260	\$ (110,604)	\$ 228,355
Coyote Station	35.0 %	182,610	1,110	(107,894)	75,826
Big Stone South–Ellendale 345 kV line	50.0 %	106,194	—	(4,052)	102,142
Fargo–Monticello 345 kV line	14.2 %	78,184	—	(9,069)	69,115
Big Stone South–Brookings 345 kV line	50.0 %	52,975	—	(3,613)	49,362
Brookings–Southeast Twin Cities 345 kV line	4.8 %	26,291	—	(2,843)	23,448
Bemidji–Grand Rapids 230 kV line	14.8 %	16,331	—	(2,995)	13,336

## 5. Short-Term and Long-Term Borrowings

### Short-Term Debt

The following is a summary of our line of credit as of December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>Line Limit</i>	<b>2022</b>		<b>2021</b>	
		<i>Amount Outstanding</i>	<i>Letters of Credit</i>	<i>Amount Available</i>	<i>Amount Available</i>
OTP Credit Agreement	170,000	8,204	9,573	152,223	88,315

On October 31, 2022, we entered into a Fourth Amended and Restated Credit Agreement, amending and restating the previously existing credit agreement to extend the maturity date of the credit facility from September 30, 2026 to October 29, 2027, and to replace LIBOR as a benchmark interest rate with the Secured Overnight Finance Rate (SOFR). The adoption of SOFR as a benchmark interest rate is in advance of the scheduled elimination of LIBOR as a benchmark interest rate on June 30, 2023. No other significant terms or conditions, including borrowing capacity, credit spreads or financial covenants, were modified under this amendment and restatement. The agreement provides for a \$170.0 million unsecured 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 \$250.0 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 the advance, subject to the conditions of the agreement plus an applicable credit spread. The credit spread ranges from zero to 1.75%, depending on the benchmark interest rate selected and is subject to adjustment based on our credit ratings. The weighted-average interest rate of our outstanding borrowings as of December 31, 2022 and 2021 was 5.61% and 1.35%, respectively.

The credit facility contains a number of restrictions, including restrictions on our 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 contains certain financial and non-financial covenants and defined events of default, as further described below.

## Long-Term Debt

The following is a summary of outstanding long-term debt as of December 31, 2022 and 2021:

Debt Instrument	Rate	Maturity	(in thousands)	
			December 31, 2022	December 31, 2021
Series 2007B Senior Unsecured Notes	6.15%	08/20/22	\$ —	\$ 30,000
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 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	—
Total			\$ 747,000	\$ 687,000

On June 10, 2021, we entered into a Note Purchase Agreement pursuant to which we agreed to issue, in a private placement transaction, \$230.0 million of senior unsecured notes consisting of (a) \$40.0 million of 2.74% Series 2021A Senior Unsecured Notes due November 29, 2031, (b) \$100.0 million of 3.69% Series 2021B Senior Unsecured Notes due November 29, 2051 and (c) \$90.0 million of 3.77% Series 2022A Senior Unsecured Notes due May 20, 2052. During the year ended December 31, 2021, we issued our Series 2021A and Series 2021B notes for aggregate proceeds of \$140.0 million, which were used to repay the Series 2011A notes. During the year ended December 31, 2022, we issued our Series 2022A notes for aggregate proceeds of \$90.0 million, which were used to repay the Series 2007B notes, to repay short-term borrowings, to fund capital expenditures and for other general corporate purposes.

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.

Maturities of long-term debt obligations as of December 31, 2022 for each of the next five years were as follows:

(in thousands)	2023	2024	2025	2026	2027
Debt Maturities	\$ —	\$ —	\$ —	\$ —	\$ 42,000

## Financial Covenants

Certain of our short-term and long-term debt agreements require us to maintain certain financial covenants, including a maximum debt to total capitalization of 0.60 to 1.00, a minimum interest and dividend coverage ratio of 1.50 to 1.00, and a maximum level of priority indebtedness. As of December 31, 2022, we were in compliance with these financial covenants.

## 6. 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 the 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, 2022 and 2021:

<i>Asset Class</i>	<i>Permitted Range</i>	<i>Actual Allocation</i>	
		<i>2022</i>	<i>2021</i>
Return Enhancement	35 – 60 %	48 %	47 %
Risk Management	40 – 80 %	51	50
Alternatives	0 – 20 %	1	3
<b>Total</b>		<b>100 %</b>	<b>100 %</b>

**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, 2022 and 2021 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>
<b>December 31, 2022</b>					
Equity Funds	\$ 121,219	\$ —	\$ —	\$ —	\$ 121,219
Fixed Income Funds	152,513	—	—	—	152,513
Hybrid Funds	9,512	—	—	—	9,512
U.S. Treasury Securities	19,098	—	—	—	19,098
SEI Energy Debt Collective Fund	—	—	—	3,611	3,611
<b>Total</b>	<b>302,342</b>	<b>—</b>	<b>—</b>	<b>3,611</b>	<b>305,953</b>
<b>December 31, 2021</b>					
Equity Funds	145,742	—	—	—	145,742
Fixed Income Funds	180,362	—	—	—	180,362
Hybrid Funds	11,482	—	—	—	11,482
U.S. Treasury Securities	27,469	—	—	—	27,469
SEI Energy Debt Collective Fund	—	—	—	12,477	12,477
<b>Total</b>	<b>\$ 365,055</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 12,477</b>	<b>\$ 377,532</b>

The investments held by the SEI Energy Debt Collective Fund on December 31, 2022 and 2021 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 asset 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, 2022 and 2021 and the funded status of the plans as of December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>
<b>Change in Fair Value of Plan Assets:</b>						
Fair Value of Plan Assets at January 1	\$ 377,532	\$ 351,661	\$ —	\$ —	\$ —	\$ —
Actual Return on Plan Assets	(75,073)	31,746	—	—	—	—
Company Contributions	20,000	10,000	1,625	1,325	2,301	2,669
Benefit Payments	(16,506)	(15,875)	(1,625)	(1,325)	(8,118)	(8,311)
Participant Premium Payments	—	—	—	—	5,817	5,642
<b>Fair Value of Plan Assets at December 31</b>	<b>305,953</b>	<b>377,532</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>Change in Benefit Obligation:</b>						
Benefit Obligation at January 1	406,280	417,686	16,924	17,887	67,578	68,430
Service Cost	6,411	7,276	—	—	1,305	1,679
Interest Cost	12,035	11,369	474	447	1,990	1,844
Benefit Payments	(16,506)	(15,875)	(3,557)	(1,326)	(8,118)	(8,311)
Participant Premium Payments	—	—	—	—	5,817	5,642
Actuarial Gain	(107,866)	(14,176)	(1,625)	(84)	(19,874)	(1,706)
<b>Benefit Obligation at December 31</b>	<b>300,354</b>	<b>406,280</b>	<b>12,216</b>	<b>16,924</b>	<b>48,698</b>	<b>67,578</b>
<b>Funded Status</b>	<b>\$ 5,599</b>	<b>\$ (28,748)</b>	<b>\$ (12,216)</b>	<b>\$ (16,924)</b>	<b>\$ (48,698)</b>	<b>\$ (67,578)</b>
<b>Amounts Recognized in Balance Sheet at December 31:</b>						
Noncurrent Assets	\$ 5,599	\$ —	\$ —	\$ —	\$ —	\$ —
Current Liabilities	—	—	(1,261)	(1,360)	(2,896)	(2,755)
Noncurrent Liabilities and Deferred Credits	—	(28,748)	(10,955)	(15,564)	(45,802)	(64,823)
<b>Net Asset (Liability)</b>	<b>\$ 5,599</b>	<b>\$ (28,748)</b>	<b>\$ (12,216)</b>	<b>\$ (16,924)</b>	<b>\$ (48,698)</b>	<b>\$ (67,578)</b>

The accumulated benefit obligation of our Pension Plan was \$276.1 million and \$368.8 million as of December 31, 2022 and 2021. The accumulated benefit obligation of our ESSRP was \$12.2 million and \$16.9 million as of December 31, 2022 and 2021.

The following assumptions were used to determine benefit obligations as of December 31, 2022 and 2021:

	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>
Discount Rate	5.51 %	3.03 %	5.51 %	2.93 %	5.52 %	3.01 %
Long-Term Rate of Compensation Increase(1)	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(1)	3.50 %	3.50 %	n/a	n/a	n/a	n/a
Participants Age 50 and Older(1)	2.75 %	2.75 %	n/a	n/a	n/a	n/a
Healthcare Cost Immediate Trend Rate	n/a	n/a	n/a	n/a	7.50 %	6.16 %
Healthcare Cost Ultimate Trend Rate	n/a	n/a	n/a	n/a	4.00 %	4.50 %
Year the Rate Reaches the Ultimate Trend Rate	n/a	n/a	n/a	n/a	2048	2038

(1) The estimated rate of compensation increase for 2023 and 2024, as estimated as of December 31, 2022, is equal to 4.00% for all participants, reflecting higher anticipated compensation changes during these years.

The measurement of the plan asset 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 2022 and 2021 reduced our obligation by \$114.2 million and \$15.3 million. A short-term increase in expected future compensation increased the benefit obligation in 2022 by \$6.6 million. The difference between actual and expected returns on Pension Plan assets also impacted our obligation in 2022 and 2021.
- For the ESSRP, an increase in the discount rate in 2022 and 2021 reduced our obligation by \$3.5 million and \$0.7 million.
- For the postretirement healthcare plan, an increase in the discount rate in 2022 and 2021 reduced our obligation by \$17.5 million and \$2.5 million. Revised estimates of healthcare cost trends and participant contribution assumptions decreased the benefit obligation by \$2.3 million in 2022.

**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 lists the components of net periodic benefit cost of our defined benefit pension plans and other postretirement benefits for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>	<i>2022</i>	<i>2021</i>
Service Cost	\$ 6,412	\$ 7,276	\$ —	\$ —	\$ 1,304	\$ 1,679
Interest Cost	12,035	11,369	474	447	1,990	1,844
Expected Return on Assets	(23,092)	(21,800)	—	—	—	—
Amortization of Prior Service Cost	—	—	—	—	(5,589)	(5,589)
Amortization of Net Actuarial Loss	7,668	10,641	308	307	2,986	3,679
<b>Net Periodic Benefit Cost</b>	<b>\$ 3,023</b>	<b>\$ 7,486</b>	<b>\$ 782</b>	<b>\$ 754</b>	<b>\$ 691</b>	<b>\$ 1,613</b>

The following table includes the impact of regulation on the recognition of periodic benefit cost arising from pension and other postretirement benefits for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>2022</i>	<i>2021</i>
Net Periodic Benefit Cost	\$ 4,496	\$ 9,853
Net Amount Amortized (Deferred) Due to the Effect of Regulation	1,121	21
<b>Net Periodic Benefit Cost Recognized</b>	<b>\$ 5,617</b>	<b>\$ 9,874</b>

The following assumptions were used to determine net periodic benefit cost for the years ended December 31, 2022 and 2021:

	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<b>2022</b>	<b>2021</b>	<b>2022</b>	<b>2021</b>	<b>2022</b>	<b>2021</b>
Discount Rate	3.03 %	2.78 %	2.93 %	2.61 %	3.01 %	2.75 %
Long-Term Rate of Return on Plan Assets	6.30 %	6.51 %	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	3.50 %	3.50 %	n/a	n/a	n/a	n/a
Participants Age 50 and Older	2.75 %	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, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension Benefits (Pension Plan)</i>		<i>Pension Benefits (ESSRP)</i>		<i>Postretirement Benefits</i>	
	<b>2022</b>	<b>2021</b>	<b>2022</b>	<b>2021</b>	<b>2022</b>	<b>2021</b>
<b>Regulatory Assets (Liabilities):</b>						
Unrecognized Prior Service Cost	\$ —	\$ —	\$ —	\$ —	\$ (8,400)	\$ (13,989)
Unrecognized Actuarial Loss	85,367	102,737	979	2,525	3,993	26,852
<b>Net Regulatory Assets (Liabilities)</b>	<b>\$ 85,367</b>	<b>\$ 102,737</b>	<b>\$ 979</b>	<b>\$ 2,525</b>	<b>\$ (4,407)</b>	<b>\$ 12,863</b>
<b>Accumulated Other Comprehensive Income (Loss):</b>						
Unrecognized Actuarial Loss	—	—	1,468	3,787	—	—
<b>Total Accumulated Other Comprehensive Income (Loss)</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 1,468</b>	<b>\$ 3,787</b>	<b>\$ —</b>	<b>\$ —</b>

**Cash Flows.** We made discretionary contributions to our Pension Plan of \$20.0 million and \$10.0 million in 2022 and 2021. As of December 31, 2022, 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:

<i>(in thousands)</i>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028-2033</b>
Projected Pension Plan Benefit Payments	\$ 17,572	\$ 18,093	\$ 18,596	\$ 19,076	\$ 19,514	\$ 103,415
Projected ESSRP Benefit Payments	1,293	1,221	1,166	1,119	1,024	4,810
Projected Postretirement Benefit Payments	2,896	3,012	3,215	3,364	3,407	17,360
<b>Total</b>	<b>\$ 21,761</b>	<b>\$ 22,326</b>	<b>\$ 22,977</b>	<b>\$ 23,559</b>	<b>\$ 23,945</b>	<b>\$ 125,585</b>

#### 401K Plan

We sponsor a 401K plan for the benefit of all company employees. Contributions made to these plans totaled 3.5 million for 2022 and 3.2 million for 2021.

## 7. Asset Retirement Obligations (AROs)

We have recognized Asset Retirement Obligations (AROs) related to our coal-fired generation plants, natural gas combustion turbines and wind turbines. The cost of AROs include items such as site restoration, closure 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.

A reconciliation of the carrying amounts of AROs for the years ended December 31, 2022 and 2021 are as follows:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
<b>Beginning Balance</b>	\$ 24,191	\$ 23,821
Adjustments Due to Revisions in Cash Flow Estimates	—	(568)
Accrued Accretion	991	938
<b>Ending Balance</b>	\$ 25,182	\$ 24,191

## 8. Income Taxes

Income before income taxes for the years ended December 31, 2022 and 2021 consists entirely of domestic earnings.

The provision for income taxes charged to income for the years ended December 31, 2022 and 2021 consisted of the following:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
<b>Current</b>		
Federal Income Taxes	\$ (22,475)	\$ (567)
State Income Taxes	(3,835)	(784)
<b>Deferred</b>		
Federal Income Taxes	22,010	(1,335)
State Income Taxes	9,954	4,938
<b>Tax Credits</b>		
North Dakota Wind Tax Credit Amortization, Net of Federal Tax	(586)	(586)
Investment Tax Credit Amortization	(3)	(3)
Total	\$ 5,065	\$ 1,663

Deferred tax assets and liabilities were composed of the following as of December 31, 2022 and 2021:

<i>(in thousands)</i>	<b>2022</b>	<b>2021</b>
<b>Deferred Tax Assets</b>		
<b>Tax Credit Carryforward</b>	\$ 55,113	\$ 57,013
Other Employee Benefits	21,037	21,465
Differences Related to Property	7,703	6,664
Cost of Removal	37,360	0
Net Operating Loss Carryforward	170	12,879
Regulatory Asset – FAS 109	2,677	750
Other	(1,823)	(2,440)
<b>Total Deferred Tax Assets</b>	\$ 122,237	\$ 96,331
<b>Deferred Tax Liabilities</b>		
Differences Related to Property	\$ (281,653)	\$ (222,571)
Pension Expense	(24,805)	(24,578)
North Dakota Wind Tax Credits	(6,111)	(6,423)
Regulatory Liability	(2,231)	(126)
Impact of State Net Operating Losses on Federal Taxes	(36)	(751)
Other	(2,743)	(4,112)
<b>Total Deferred Tax Liabilities</b>	(317,579)	(258,561)
<b>Deferred Income Taxes</b>	\$ (195,342)	\$ (162,230)

The reconciliation of the statutory federal income tax rate to our effective tax rate for each of the years ended December 31, 2022 and 2021 is as follows:

	2022		2021			
Income Taxes at Federal Statutory Rate	\$	17,858	21.0 %	\$	15,565	21.0 %
State Taxes on Income, Net of Federal Tax		4,283	5.0		3,777	5.1
Production Tax Credits (PTCs)		(14,985)	(17.6)		(12,503)	(16.9)
Amortization of Excess Deferred Income Taxes		(1,625)	(1.9)		(3,967)	(5.4)
North Dakota Wind Tax Credit Amortization, Net of Federal Tax		(586)	(0.7)		(586)	(0.8)
Allowance for Equity Funds Used During Construction		(440)	(0.5)		(214)	(0.3)
Other, Net		560	0.7		(409)	(0.5)
<b>Income Taxes at Effective Tax Rate</b>	<b>\$</b>	<b>5,065</b>	<b>6.0 %</b>	<b>\$</b>	<b>1,663</b>	<b>2.2 %</b>

The following is a schedule of tax credits and net operating losses available as of December 31, 2022 and the respective periods of expiration:

<i>(in thousands)</i>	<i>Amount</i>	<i>2023-2029</i>	<i>2030-2037</i>
Federal Tax Credits	\$ 22,688	\$ —	\$ 22,688
State Net Operating Losses	170	—	170
State Tax Credits	29,101	—	29,101

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, 2022 and 2021, \$25.2 million and \$26.6 million of net operating loss and tax credit carryforwards were used, or expected to be used, in the consolidated income tax returns. 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, 2022 and 2021, we had no unrecognized tax benefits and the amount of unrecognized tax benefits as of December 31, 2022 is not expected to change significantly within the next 12 months.

As of December 31, 2022, with limited exceptions, we are no longer subject to examinations by taxing authorities for tax years prior to 2019 for federal and North Dakota income taxes and prior to 2018 for Minnesota state income taxes.

## 9. Commitments and Contingencies

### Commitments

**Ashtabula III Purchase.** Since 2013, we had purchased the wind-generated electricity from the Ashtabula III, a 62.4-megawatt wind farm located in eastern North Dakota, pursuant to a power purchase agreement. That agreement granted us the option to purchase the wind farm, and in June 2022, we exercised our option. On January 3, 2023, we acquired Ashtabula III for \$50.6 million.

**Construction and Other Commitments.** As of December 31, 2022, we had commitments under contracts for construction project materials, plant maintenance and other services extending into 2046 which totaled approximately \$21.5 million.

**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 2033. Generally, the terms of our wind power purchase agreements require us to purchase all of the electricity generated by a particular wind farm and do not include fixed or minimum payments. The required payments are variable and the amounts due are determined based upon the amount of electricity generated. Capacity and energy requirement costs under these agreements totaled \$13.1 million and \$11.5 million for the years ended December 31, 2022 and 2021.

**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 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, 2024. There is no fixed minimum purchase requirement under this agreement but all of Big Stone Plant's coal requirements for the period covered must be purchased under this agreement. Coal purchase costs under these agreements totaled \$45.1 million and \$40.4 million for the years ended December 31, 2022 and 2021.

**Land Easement Payments.** We have commitments to make payments for land easements not classified as leases, extending into 2050 of approximately \$33.1 million. Land easement costs under these agreements totaled \$1.4 million and \$1.3 million for the years ended December 31, 2022 and 2021.

Our future commitments as of December 31, 2022 were as follows:

<i>(in thousands)</i>	<i>Construction Program and Other Commitments</i>	<i>Capacity and Energy Requirements</i>	<i>Coal Purchase Commitments</i>	<i>Land Easement Payments</i>
2023	\$ 12,423	\$ 298	\$ 23,955	\$ 1,388
2024	934	272	24,369	1,412
2025	472	228	25,103	1,437
2026	479	197	25,716	1,432
2027	487	197	25,804	1,457
Beyond 2027	6,660	3,939	402,500	26,004
<b>Total</b>	<b>\$ 21,455</b>	<b>\$ 5,131</b>	<b>\$ 527,447</b>	<b>\$ 33,130</b>

**Contingencies**

**FERC ROE.** In November 2013 and February 2015, customers filed complaints with the 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’s most recent order, issued on November 19, 2020, 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. The U.S. Court of Appeals remanded the matter to FERC to reopen the proceedings.

Significant uncertainty exists as to how FERC will proceed on remand and there is no prescribed timeline under which FERC must act. We have deferred recognition and recorded a refund liability of \$2.6 million as of December 31, 2022. This refund liability reflects our best estimate of amounts previously collected from customers under the MISO tariff rate that may be required to be refunded to customers once all regulatory and judicial proceedings are complete and a final ROE is established for the periods outlined above.

**Regional Haze Rule (RHR).** The RHR was adopted in an effort to improve visibility in national parks and wilderness areas. The RHR requires states, in coordination with the Environmental Protection Agency and other governmental agencies, to develop and implement plans to achieve natural visibility conditions. The second RHR implementation period covers the years 2018-2028. States are required to submit a state implementation plan to assess reasonable progress with the RHR and determine what additional emission reductions are appropriate, if any.

Coyote Station, our jointly-owned coal-fired power plant in North Dakota, is subject to assessment in the second implementation period under the North Dakota state implementation plan. The NDDEQ submitted its state implementation plan to the EPA for approval in August 2022. In its plan, the NDDEQ concluded it is not reasonable to require additional emission controls during this planning period. The EPA has previously expressed disagreement with the NDDEQ’s recommendation to forgo additional emission controls and has indicated that such a plan is not likely to be accepted.

We cannot predict with certainty the impact the state implementation plan may have on our business until the state implementation plan has been approved or otherwise acted on by the EPA. However, significant emission control investments could be required and the recovery of such costs from customers would require regulatory approval. Alternatively, investments in emission control equipment may prove to be uneconomic and result in the early retirement of or the sale of our interest in Coyote Station, subject to regulatory approval. We cannot estimate the ultimate financial effects such a retirement or sale may have on our operating results, financial position or cash flows, but such amounts could be material and the recovery of such costs in rates would be subject to regulatory approval.

**Self-Funding of Transmission Upgrades.** The FERC has granted transmission owners within MISO 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 has 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 hearing, 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. On December 2, 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.

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 FERC, on remand from the Court of Appeals, 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 and when FERC may respond to the judicial remand.

**Other Contingencies.** We are party to litigation and regulatory enforcement matters arising in the normal course of business. We regularly analyze relevant information and, as necessary, estimate and record accrued liabilities for 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, 2022 will not be material.

## 10. Accumulated Other Comprehensive Income (Loss)

The Company's other comprehensive income 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 income are recognized in the same period as the amounts are reclassified.

The following table shows the changes in accumulated other comprehensive loss for the years ended December 31, 2022 and 2021:

<i>(in thousands)</i>	<i>Pension and Other Postretirement Benefits</i>
Balance, December 31, 2020	\$ (2,966)
Other Comprehensive Income Before Reclassifications, net of tax	39
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) <sup>(1)</sup>	128
Total Other Comprehensive Income	167
Balance, December 31, 2021	\$ (2,799)
Other Comprehensive Income Before Reclassifications, net of tax	1,987
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) <sup>(1)</sup>	(274)
Total Other Comprehensive Income	1,713
<b>Balance, December 31, 2022</b>	<b>\$ (1,086)</b>

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

## 11. 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, 2022, 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 MPUC indirectly limits the amount of dividends we can pay to Otter Tail Corporation by requiring an equity-to-total-capitalization ratio between 47.5% and 58.0%, with total capitalization not to exceed \$1.8 billion based on our capital structure requirements as of December 31, 2022. As of December 31, 2022, our equity-to-total-capitalization ratio including short-term debt was 54.7% and our net assets restricted from distribution totaled approximately \$737.4 million.

## 12. Derivative Instruments

We enter into derivative instruments to manage our exposure to future commodity price variability and reduce volatility in prices for our retail electric customers. These derivative instruments are not designated as qualifying hedging transactions but provide for an economic hedge against future price variability. The instruments are recorded at fair value on our balance sheets, with changes in fair value recorded in the statements of comprehensive income. However, 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, 2022 and 2021, we had outstanding pay-fixed, receive-variable swap agreements with an aggregate notional amount of 295,000 and 263,400 megawatt-hours of electricity. The contracts outstanding as of December 31, 2022 had various settlement dates throughout 2023. As of December 31, 2022 and 2021, the fair value of these derivative instruments was \$7.1 million, which is included in other current liabilities, and \$6.2 million, which is included in other current assets, on our balance sheets. During the years ended December 31, 2022 and 2021, contracts matured and were settled in an aggregate amount of \$1.0 million and \$3.1 million.

### 13. Fair Value of Financial Instruments

The following tables present our assets and liabilities measured at fair value on a recurring basis as of December 31, 2022 and 2021 classified by the input method used to measure fair value:

	Level 1		Level 2		Level 3	
<b>December 31, 2022</b>						
Liabilities:						
Derivative Instruments	\$	—	\$	7,130	\$—	
Total Liabilities	\$	—	\$	7,130	\$	—
December 31, 2021						
Assets:						
Derivative Instruments	\$	—	\$	6,214	\$	—
Total Assets	\$	—	\$	6,214	\$	—

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, 2022 and 2021:

<i>(in thousands)</i>	December 31, 2022		December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
<b>Assets:</b>				
Cash and Cash Equivalents	\$ 18	\$ 18	\$ 15	\$ 15
<b>Liabilities:</b>				
Short-Term Debt	\$ 8,204	\$ 8,204	\$ 68,526	\$ 68,526
Long-Term Debt	747,000	608,741	687,000	795,910

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

**Cash Equivalents:** The carrying amount approximates fair value because of the short-term maturity of these instruments.

**Short-Term Debt:** The carrying amount approximates fair value because the debt obligations are short-term 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.

### 14. Related Party Transactions

Included in the amounts presented in the balance sheets and statements of comprehensive income as of and for the years ended December 31, 2022 and 2021 are the following related party transaction balances:

<i>(in thousands)</i>	2022	2021
Accounts Receivable	\$ 7	\$ 7
Accounts Payable	3,016	2,503
Operating Revenues	27	40
Operating and Maintenance Expenses	13,031	13,582

Operating and maintenance expenses predominately 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 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. OTP received \$26.5 million and \$1.0 million during the years ended December 31, 2022 and 2021, respectively, from Otter Tail Corporation in exchange for these tax credits and other tax benefits. In February 2023, OTP received \$25.2 million from Otter Tail Corporation in exchange for certain tax credits and other tax benefits.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(2,965,964)			(2,965,964)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value				167,055			167,055		
4	Total (lines 2 and 3)				167,055			167,055	72,457,845	72,624,900
5	Balance of Account 219 at End of Preceding Quarter/Year				(2,798,909)			(2,798,909)		
6	Balance of Account 219 at Beginning of Current Year				(2,798,909)			(2,798,909)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value				1,712,904			1,712,904		
9	Total (lines 7 and 8)				1,712,904			1,712,904	79,974,186	81,687,090
10	Balance of Account 219 at End of Current Quarter/Year				(1,086,005)			(1,086,005)		

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**SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION**

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	\$2,314,916,778	2,314,916,778					
4	Property Under Capital Leases							
5	Plant Purchased or Sold							
6	Completed Construction not Classified	534,840,722	534,840,722					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	2,849,757,500	2,849,757,500					
9	Leased to Others							
10	Held for Future Use	12,038	12,038					
11	Construction Work in Progress	\$118,374,711	118,374,711					
12	Acquisition Adjustments	1,647,128	1,647,128					
13	Total Utility Plant (8 thru 12)	2,969,791,377	2,969,791,377					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	985,407,109	985,407,109					
15	Net Utility Plant (13 less 14)	1,984,384,268	1,984,384,268					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	972,533,783	972,533,783					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	11,226,198	11,226,198					
22	Total in Service (18 thru 21)	983,759,981	983,759,981					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	1,647,128	1,647,128					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	985,407,109	985,407,109					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: UtilityPlantInServiceClassified

Per its FERC-approved tariff, the Company uses a 13-month average of gross electric plant in service for rate-making purposes, illustrated as follows for the current year:

	<b>Gross Electric Plant In Service</b>
December 31, 2021	2,248,303,719
January 31, 2022	2,251,160,714
February 28, 2022	2,260,214,174
March 31, 2022	2,268,502,566
April 30, 2022	2,269,121,173
May 31, 2022	2,274,295,504
June 30, 2022	2,279,220,379
July 31, 2022	2,287,369,667
August 31, 2022	2,288,932,546
September 30, 2022	2,292,116,623
October 31, 2022	2,297,895,726
November 30, 2022	2,304,179,775
December 31, 2022	2,314,916,778
13-month average for rate-making	2,279,709,950

(b) Concept: ConstructionWorkInProgress

Per its FERC-approved tariff, the Company uses a 13-month average of CWIP for rate-making purposes, illustrated as follows for the current year:

	<b>CWIP</b>
December 31, 2021	76,740,501
January 31, 2022	80,444,221
February 28, 2022	71,880,246
March 31, 2022	74,669,450
April 30, 2022	81,789,285
May 31, 2022	95,345,694
June 30, 2022	98,960,969
July 31, 2022	107,248,690
August 31, 2022	123,397,451
September 30, 2022	133,405,265
October 31, 2022	139,653,084
November 30, 2022	141,633,092
December 31, 2022	118,374,711
13-month average for rate-making	103,349,435

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)**

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.  
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)**

- Report below the original cost of electric plant in service according to the prescribed accounts.
- In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
- Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
- For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
- For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	1,301,974	1,998,445	1,301,974			1,998,445
4	(303) Miscellaneous Intangible Plant	30,307,850	1,154,992	1,464,242			29,998,600
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	31,609,824	3,153,437	2,766,216			31,997,045
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	1,654,157					1,654,157
9	(311) Structures and Improvements	121,321,647	242,889	7,948			121,556,588
10	(312) Boiler Plant Equipment	355,431,574	1,432,633	1,375,641			355,488,566
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	66,541,576	56,097				66,597,673
13	(315) Accessory Electric Equipment	35,972,201	5,374				35,977,575
14	(316) Misc. Power Plant Equipment	6,991,001	250,254	136,844			7,104,411
15	(317) Asset Retirement Costs for Steam Production	2,881,917					2,881,917
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	590,794,073	1,987,247	1,520,433			591,260,887
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	299,623					299,623
28	(331) Structures and Improvements	351,712	150,737	16,203	492		486,738
29	(332) Reservoirs, Dams, and Waterways	7,696,517	(87,853)	2,253	(492)		7,605,919
30	(333) Water Wheels, Turbines, and Generators	1,373,867					1,373,867
31	(334) Accessory Electric Equipment	1,052,626	42,259				1,094,885
32	(335) Misc. Power Plant Equipment	435,296		270			435,026
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	11,209,641	105,143	18,726			11,296,058
36	D. Other Production Plant						
37	(340) Land and Land Rights	126,762					126,762
38	(341) Structures and Improvements	44,738,890	1,624,627				46,363,517

39	(342) Fuel Holders, Products, and Accessories	7,355,560	556,020				7,911,580
40	(343) Prime Movers	133,013,316	6,285,292	591,638			138,706,970
41	(344) Generators	480,657,217	1,742,445	620,079			481,779,583
42	(345) Accessory Electric Equipment	45,856,631	754,805				46,611,436
43	(346) Misc. Power Plant Equipment	2,267,340	76,986	56,736			2,287,590
44	(347) Asset Retirement Costs for Other Production	13,352,416					13,352,416
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	727,368,132	11,040,175	1,268,453			737,139,854
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,329,371,846	13,132,565	2,807,612			1,339,696,799
47	3. Transmission Plant						
48	(350) Land and Land Rights	21,711,725	2,233,633	555	2,185		23,946,988
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements						
50	(353) Station Equipment	169,006,870	12,753,624	1,976,725	2,832,899		182,616,668
51	(354) Towers and Fixtures	191,044,804	5,970,124				197,014,928
52	(355) Poles and Fixtures	163,278,822	5,748,621	440,494			168,586,949
53	(356) Overhead Conductors and Devices	178,312,969	7,315,965	490,511			185,138,423
54	(357) Underground Conduit						
55	(358) Underground Conductors and Devices	99,467	4,095				103,562
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	723,454,657	34,026,062	2,908,285	2,835,084		757,407,518
59	4. Distribution Plant						
60	(360) Land and Land Rights	1,431,213	65,629	17,619	15,434		1,494,657
61	(361) Structures and Improvements						
62	(362) Station Equipment	93,989,897	5,014,647	1,092,409	(2,832,899)		95,079,236
63	(363) Energy Storage Equipment - Distribution						
64	(364) Poles, Towers, and Fixtures	81,910,746	5,049,553	173,496			86,786,803
65	(365) Overhead Conductors and Devices	58,583,120	2,593,714	300,343			60,876,491
66	(366) Underground Conduit						
67	(367) Underground Conductors and Devices	101,015,177	14,101,931	430,989			114,686,119
68	(368) Line Transformers	120,031,810	9,887,502	569,496			129,349,816
69	(369) Services	61,784,176	2,287,304	39,371			64,032,109
70	(370) Meters	37,606,242	490,854	121,054			37,976,042
71	(371) Installations on Customer Premises	8,559,303	1,204,799	109,274			9,654,828
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	10,440,649	3,074,689	280,071			13,235,267
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	575,352,333	43,770,622	3,134,122	(2,817,465)		613,171,368
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	1,597,841					1,597,841
87	(390) Structures and Improvements	35,030,413	2,385,481	37,402	(70,755)		37,307,737

88	(391) Office Furniture and Equipment	9,249,519	730,001	2,323,462	2,898	7,658,956
89	(392) Transportation Equipment	41,283,143	3,023,287	1,857,522		42,448,908
90	(393) Stores Equipment					
91	(394) Tools, Shop and Garage Equipment	5,728,006	715,887	589,444		5,854,449
92	(395) Laboratory Equipment					
93	(396) Power Operated Equipment	1,517,303	203,374	19,151		1,701,526
94	(397) Communication Equipment	10,153,679	1,143,163	449,346	67,857	10,915,353
95	(398) Miscellaneous Equipment					
96	SUBTOTAL (Enter Total of lines 86 thru 95)	104,559,904	8,201,193	5,276,327		107,484,770
97	(399) Other Tangible Property					
98	(399.1) Asset Retirement Costs for General Plant					
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	104,559,904	8,201,193	5,276,327		107,484,770
100	TOTAL (Accounts 101 and 106)	2,764,348,564	102,283,879	16,892,562	17,619	2,849,757,500
101	(102) Electric Plant Purchased (See Instr. 8)					
102	(Less) (102) Electric Plant Sold (See Instr. 8)					
103	(103) Experimental Plant Unclassified					
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	2,764,348,564	102,283,879	16,892,562	17,619	2,849,757,500

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: IntangiblePlant

Per its FERC-approved tariff, the Company uses a 13-month average of intangible electric plant in service for rate-making purposes, illustrated as follows for the current year:

	Intangible Electric Plant in Service
December 31, 2021	31,609,824
January 31, 2022	31,609,887
February 28, 2022	33,536,908
March 31, 2022	33,595,940
April 30, 2022	33,595,940
May 31, 2022	33,595,940
June 30, 2022	34,066,939
July 31, 2022	34,139,937
August 31, 2022	33,701,895
September 30, 2022	33,722,612
October 31, 2022	33,742,514
November 30, 2022	33,694,384
December 31, 2022	31,997,045
13-month average for rate-making	33,277,674

(b) Concept: ProductionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of production plant in service for rate-making purposes, illustrated as follows for the current year:

	Production Plant in Service
December 31, 2021	1,329,371,847
January 31, 2022	1,329,284,490
February 28, 2022	1,328,865,536
March 31, 2022	1,328,447,060
April 30, 2022	1,328,261,518
May 31, 2022	1,327,214,711
June 30, 2022	1,327,710,897
July 31, 2022	1,327,054,445
August 31, 2022	1,327,087,624
September 30, 2022	1,328,094,596
October 31, 2022	1,330,463,086
November 30, 2022	1,331,359,624
December 31, 2022	1,339,696,799
13-month average for rate-making	1,329,454,787

(c) Concept: TransmissionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of electric transmission plant in service for rate-making purposes, illustrated as follows for the current year:

	Electric Transmission Plant in Service
December 31, 2021	723,454,654
January 31, 2022	724,033,564
February 28, 2022	730,992,300
March 31, 2022	736,271,741
April 30, 2022	736,499,037
May 31, 2022	735,750,194
June 30, 2022	740,521,325
July 31, 2022	743,245,176
August 31, 2022	744,398,510
September 30, 2022	744,707,931
October 31, 2022	744,976,362
November 30, 2022	745,430,615
December 31, 2022	757,407,518
13-month average for rate-making	739,052,994

(d) Concept: DistributionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of distribution plant in service for rate-making purposes, illustrated as follows for the current year:

	Distribution Plant in Service
December 31, 2021	575,352,332
January 31, 2022	577,286,896
February 28, 2022	580,979,658
March 31, 2022	579,446,129
April 30, 2022	580,133,695
May 31, 2022	580,521,967
June 30, 2022	583,617,110
July 31, 2022	585,031,352
August 31, 2022	586,686,644
September 30, 2022	589,797,721
October 31, 2022	595,236,352
November 30, 2022	601,805,290
December 31, 2022	613,171,368
13-month average for rate-making	586,851,270

(e) Concept: GeneralPlant

Per its FERC-approved tariff, the Company uses a 13-month average of general plant in service for rate-making purposes, illustrated as follows for the current year:

	General Plant in Service
December 31, 2021	104,559,908
January 31, 2022	105,615,260
February 28, 2022	105,012,045
March 31, 2022	105,038,114
April 30, 2022	105,565,991
May 31, 2022	106,268,701
June 30, 2022	106,056,138
July 31, 2022	105,757,430
August 31, 2022	105,950,298
September 30, 2022	105,146,332
October 31, 2022	104,434,072
November 30, 2022	104,579,816
December 31, 2022	107,484,770
13-month average for rate-making	105,497,606

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ELECTRIC PLANT LEASED TO OTHERS (Account 104)**

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)**

1. Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
2. For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Various			12,038
21	Other Property:			
22	Various			
47	TOTAL			12,038

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: ElectricPlantHeldForFutureUse

Per its FERC-approved tariff, the Company uses a 13-month average of electric plant held for future use for rate-making purposes, illustrated as follows for the current year:

	Transmission	Distribution	Total
December 31, 2021	9,038	20,619	29,656
January 31, 2022	9,038	20,619	29,656
February 28, 2022	9,038	3,000	12,038
March 31, 2022	9,038	3,000	12,038
April 30, 2022	9,038	3,000	12,038
May 31, 2022	9,038	3,000	12,038
June 30, 2022	9,038	3,000	12,038
July 31, 2022	9,038	3,000	12,038
August 31, 2022	9,038	3,000	12,038
September 30, 2022	9,038	3,000	12,038
October 31, 2022	9,038	3,000	12,038
November 30, 2022	9,038	3,000	12,038
December 31, 2022	9,038	3,000	12,038
13-month average for rate-making			14,748

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)**

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Hoot Lake Solar	39,433,088
2	AMI - Project Deployment	4,511,862
3	UI Upgrade with COSS Module	3,475,001
4	Erie 230/115 substation	2,866,810
5	GIS Innovation	2,403,442
6	Aneta McVilke Rebuild 41.6kV Line	2,322,782
7	Cooling Tower Replace	2,312,960
8	Astoria LTSA	2,251,869
9	Transformer Milestone Payment	1,454,438
10	Canby ASB Replacement	1,414,633
11	Fergus - New Buse Express	1,397,799
12	Hoot Lake Transformer TO Replacement	1,343,386
13	Maple River Contol House Project	1,283,559
14	Winger 230/115 Transformer	1,266,913
15	Otter Tail North Feeder Upgrade	1,152,701
16	Finley/McVilke Rebuild	1,138,717
17	AMI Meters	1,134,157
18	Ashtabula III	1,082,447
19	Total Projects under \$1,000,000	46,128,147
43	Total	118,374,711

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)**

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
<b>Section A. Balances and Changes During Year</b>					
1	Balance Beginning of Year	924,659,107	924,659,107		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	64,650,111	64,650,111		
4	(403.1) Depreciation Expense for Asset Retirement Costs	521,899	521,899		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,342,895	2,342,895		
7	Other Clearing Accounts	(22,854)	<sup>B</sup> (22,854)		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	67,492,051	67,492,051		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(14,126,342)	(14,126,342)		
13	Cost of Removal	(4,811,272)	(4,811,272)		
14	Salvage (Credit)	1,798,718	1,798,718		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(17,138,896)	(17,138,896)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(2,478,479)	<sup>C</sup> (2,478,479)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	972,533,783	<sup>B</sup> 972,533,783		
<b>Section B. Balances at End of Year According to Functional Classification</b>					
20	Steam Production	309,552,766	309,552,766		
21	Nuclear Production				
22	Hydraulic Production-Conventional	5,951,710	5,951,710		
23	Hydraulic Production-Pumped Storage				
24	Other Production	188,337,666	188,337,666		
25	Transmission	169,043,983	169,043,983		
26	Distribution	254,418,516	254,418,516		
27	Regional Transmission and Market Operation				
28	General	45,229,142	45,229,142		
29	TOTAL (Enter Total of lines 20 thru 28)	972,533,783	<sup>B</sup> 972,533,783		

FOOTNOTE DATA

(a) Concept: OtherClearingAccounts

Inventory costs cleared to construction or utility operating expense.

(b) Concept: OtherAdjustmentsToAccumulatedDepreciation

The net activity during the year for construction/removal not classified

(c) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Per its FERC-approved tariff, the company uses a 13 month average of accumulated depreciation of production, transmission, distribution and general plant for rate-making purposes, illustrated as follows for the current year:

	Production	Transmission	Distribution	General Plant	Total
12/31/2021	475,333,202	159,690,364	245,092,169	44,543,371	924,659,107
1/31/2022	478,012,164	160,958,252	245,356,435	44,851,132	929,177,983
2/28/2022	480,383,336	161,926,641	246,378,804	43,354,643	932,043,423
3/31/2022	482,864,817	163,229,730	246,830,421	43,588,929	936,513,896
4/30/2022	485,629,912	164,290,589	248,155,017	43,653,071	941,728,590
5/31/2022	487,389,962	165,112,952	249,134,864	44,111,137	945,748,915
6/30/2022	489,391,790	165,883,325	249,627,879	44,360,214	949,263,209
7/31/2022	491,060,804	166,429,145	250,558,576	44,477,283	952,525,808
8/31/2022	493,981,323	167,435,262	251,244,526	44,955,560	957,616,670
9/30/2022	496,366,277	167,706,000	252,528,783	44,543,377	961,144,438
10/31/2022	498,572,416	167,440,258	253,286,354	44,708,815	964,007,843
11/30/2022	501,076,039	167,805,527	254,095,644	45,247,783	968,224,993
12/31/2022	503,842,143	169,043,983	254,418,516	45,229,142	972,533,783
13-month average for rate-making	489,531,091	165,150,156	249,746,768	44,432,651	948,860,666

\*Production is a total of lines 20 through 24 on page 219.

(d) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Per its FERC-approved tariff, the company uses a 13 month average of accumulated depreciation of production, transmission, distribution and general plant for rate-making purposes, illustrated as follows for the current year:

	Production	Transmission	Distribution	General Plant	Total
12/31/2021	475,333,202	159,690,364	245,092,169	44,543,371	924,659,107
1/31/2022	478,012,164	160,958,252	245,356,435	44,851,132	929,177,983
2/28/2022	480,383,336	161,926,641	246,378,804	43,354,643	932,043,423
3/31/2022	482,864,817	163,229,730	246,830,421	43,588,929	936,513,896
4/30/2022	485,629,912	164,290,589	248,155,017	43,653,071	941,728,590
5/31/2022	487,389,962	165,112,952	249,134,864	44,111,137	945,748,915
6/30/2022	489,391,790	165,883,325	249,627,879	44,360,214	949,263,209
7/31/2022	491,060,804	166,429,145	250,558,576	44,477,283	952,525,808
8/31/2022	493,981,323	167,435,262	251,244,526	44,955,560	957,616,670
9/30/2022	496,366,277	167,706,000	252,528,783	44,543,377	961,144,438
10/31/2022	498,572,416	167,440,258	253,286,354	44,708,815	964,007,843
11/30/2022	501,076,039	167,805,527	254,095,644	45,247,783	968,224,993
12/31/2022	503,842,143	169,043,983	254,418,516	45,229,142	972,533,783
13-month average for rate-making	489,531,091	165,150,156	249,746,768	44,432,651	948,860,666

\*Production is a total of lines 20 through 24 on page 219.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)**

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
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7								
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9								
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28								
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31								
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33								
34								
35								
36								
37								
38								
39								
40								
41								
42	Total Cost of Account 123.1 \$		Total					



Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**MATERIALS AND SUPPLIES**

- For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
- Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	9,708,604	11,000,592	Production
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	7,783,965	8,472,303	Production
8	Transmission Plant (Estimated)	7,928,885	11,724,877	Various
9	Distribution Plant (Estimated)	9,568,508	12,224,695	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	253,067	294,270	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	25,534,425	32,716,145	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	35,243,029	43,716,737	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: FuelStock

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Fuel Stock
December 31, 2021	9,708,604
January 31, 2022	9,523,141
February 28, 2022	9,657,742
March 31, 2022	9,222,089
April 30, 2022	10,859,822
May 31, 2022	11,851,251
June 30, 2022	10,513,083
July 31, 2022	9,204,492
August 31, 2022	8,370,592
September 30, 2022	8,546,971
October 31, 2022	9,277,920
November 30, 2022	10,316,127
December 31, 2022	11,000,592
13-month average for rate-making	9,850,187

(b) Concept: PlantMaterialsAndOperatingSuppliesProductionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Production Plant
December 31, 2021	7,783,965
January 31, 2022	7,769,449
February 28, 2022	7,832,315
March 31, 2022	7,834,940
April 30, 2022	8,139,820
May 31, 2022	8,202,790
June 30, 2022	8,171,727
July 31, 2022	8,198,617
August 31, 2022	8,265,558
September 30, 2022	8,313,629
October 31, 2022	8,262,794
November 30, 2022	8,409,289
December 31, 2022	8,472,303
13-month average for rate-making	8,127,477

(c) Concept: PlantMaterialsAndOperatingSuppliesTransmissionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Transmission Plant
December 31, 2021	7,928,885
January 31, 2022	7,573,390
February 28, 2022	7,898,894
March 31, 2022	8,176,251
April 30, 2022	8,222,223
May 31, 2022	8,959,263
June 30, 2022	8,948,010
July 31, 2022	9,083,322
August 31, 2022	9,981,252
September 30, 2022	10,298,280
October 31, 2022	10,649,450
November 30, 2022	11,171,711
December 31, 2022	11,724,877
13-month average for rate-making	9,278,139

(d) Concept: PlantMaterialsAndOperatingSuppliesDistributionPlant

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Distribution Plant
December 31, 2021	9,568,508
January 31, 2022	10,398,436
February 28, 2022	10,632,267
March 31, 2022	11,405,204
April 30, 2022	11,903,389
May 31, 2022	12,353,165
June 30, 2022	11,435,101
July 31, 2022	11,971,559
August 31, 2022	11,815,318
September 30, 2022	13,082,761
October 31, 2022	11,265,505
November 30, 2022	11,804,216
December 31, 2022	12,224,695
13-month average for rate-making	11,527,702

(e) Concept: PlantMaterialsAndOperatingSuppliesOther

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Assigned to - Other
December 31, 2021	253,067
January 31, 2022	254,457
February 28, 2022	259,536
March 31, 2022	264,796
April 30, 2022	278,645
May 31, 2022	291,523
June 30, 2022	292,884
July 31, 2022	289,093
August 31, 2022	285,282
September 30, 2022	281,023
October 31, 2022	281,106
November 30, 2022	284,103
December 31, 2022	294,270
13-month average for rate-making	277,674



42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	203	8						203	2	406	10	
45	Gains	203	8						203	2	406	10	
46	Losses												

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber

Includes 1,256 of initial allocations from EPA and 1,136 of rollover allowances for Cross State Air Pollution Rule.

(b) Concept: AllowanceInventory

Renewable Energy Credits and emissions allowances are held in the Allowance inventory account (158.1) for future use.

	2021	2022
Hoot Lake Plant Allowance	181	0
Solar REC Emission Allowance Inventory	90,766	90,766
Co-gen REC Emission Allowance Inventory	10,015	21,118
	100,962	111,884



41														
42	Sales													
43	Net Sales Proceeds (Assoc. Co.)													
44	Net Sales Proceeds (Other)													
45	Gains													
46	Losses													

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber

Includes 876 of initial allocations from EPA and 3,060 rollover allowances for Cross State Air Pollution Rule.

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**EXTRAORDINARY PROPERTY LOSSES (Account 182.1)**

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not applicable.					
20	TOTAL					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)**

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	BSII Cancelled Project - MN	72,910		See Note	72,910	
22	-Transmission					
23	MPUC order issued 04-25-2011					
24	May 2013 - March 2021					
25	BSII Cancelled Project - SD	108,168		407	108,168	
26	SDPUC order issued 02-15-2019					
27	October 2018 - September 2022					
28	Hoot Lake Plant Depreciation - MN	2,138,822		407.4	984,719	1,154,103
29	Hoot Lake Plant Depreciation - ND	878,971		407.4	878,971	
30	Hoot Lake Plant Depreciation - SD	218,423		407.4	218,423	
31	July 2021 - June -2022 (ND and SD)					
32	MPUC order issued 10-6-2020					
33	Hoot Lake Hydro Depreciation - MN	173,486		407.4	17,349	156,137
49	TOTAL	3,590,780			2,280,540	1,310,240

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

<b>(a)</b> Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts
The MN Hoot Lake Plant Depreciation balance booked to account 18212101 has an amortization period of July 2022 - June 2027. The MN Hoot Lake Plant Depreciation booked to 18212104 completed amortization in June 2022.
<b>(b)</b> Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts
The MN Hoot Lake Hydro Depreciation balance will be deferred until the next rate case
<b>(c)</b> Concept: UnrecoveredPlantAndRegulatoryStudyCostsWrittenOffAccountCharged
Accounts 407 and 419 were used. <b>FERC FORM No. 1 (ED. 12-88)</b>

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**Transmission Service and Generation Interconnection Study Costs**

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period	Account Credited With Reimbursement
				(d)	(e)
1	<b>Transmission Studies</b>				
2	Forman Transformer MPFP Facility Study	13,137	456	13,137	456
3	MPFP - Xcel Fergus-Canby Area	1,075	456	1,075	456
20	Total	14,212		14,212	
21	<b>Generation Studies</b>				
22	J1456 - Lincoln Valley IC FS	53	456		456
23	J1371/J1485 Astoria IC FS	53	456		456
24	J1328 Big Stone Solar	69	456		456
25	J722 NWE Big Stone to Blair	191	456		456
26	DSIS-16 Northland FAS	8,816	456	8,816	456
27	J1575 - Donaldson Wind FAS	9,743	456	5,871	456
28	J1622 - Lincoln Valley Solar FAS	7,091	456	3,053	456
29	J722 SSR Study	550,459	456	550,756	456
39	Total	576,475		568,496	
40	Grand Total	590,687		582,708	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: StudyCostsReimbursements

Deposits are received for various studies, however these deposits are not included in the reimbursements column until the costs are incurred. The deposits are recorded to FERC 252 respectively.

FERC FORM No. 1 (NEW. 03-07)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**OTHER REGULATORY ASSETS (Account 182.3)**

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	<sup>(a)</sup> Asset Retirement Obligations-Capitalized:					
2	Hoot Lake Plant	2,656,728	321,864	230	252,938	2,725,654
3	Big Stone Plant	834,554	70,219	407.4	8,600	896,173
4	Coyote Station	3,523,966	310,441			3,834,407
5	Astoria Station	97,178	99,098			196,276
6	Wind Generation - Langdon	881,331	158,447			1,039,778
7	Wind Generation - Ashtabula	830,482	190,353			1,020,835
8	Wind Generation - Luverne	849,473	207,346			1,056,819
9	Wind Generation - Merricourt	402,917	417,224			820,141
10	Post-retirement Benefit Plans:					
11	ESSRP	2,524,800	123,181	228.3	1,669,112	978,869
12	Pension	102,736,704	7,668,102	228.3	25,037,903	85,366,903
13	Post Retirement Medical Benefits	15,466,386	8,575,480	228.3	22,859,460	1,182,406
14	Alternative Revenue Program Riders:					
15	<sup>(a)</sup> MN Transmission Cost Recovery Rider Accrued Revenues	6,265,086	1,268,523	See Note	6,448,223	1,085,386
16	<sup>(a)</sup> MN Renewable Resource Rider Accrued Revenues	4,695,658	5,332,713	See Note	6,831,911	3,196,460
17	<sup>(a)</sup> MN EITE Cost Recovery Rider		15,859	See Note	15,859	
18	<sup>(a)</sup> Conservation Improvement Program Costs & Incentives - MN	5,808,338	5,682,688	186	8,931,326	2,559,700
19	<sup>(b)</sup> Energy Efficiency Program - SD	682,565	182,218	186	471,528	393,255
20	<sup>(a)</sup> SD Phase in Rider		90,580	See Note	90,580	
21	<sup>(a)</sup> MN EUIC Rider for AMI		45,098	See Note	45,098	
22	<sup>(b)</sup> MN Decoupling		1,049,788	441,442, 445	98,453	951,335
23	<sup>(b)</sup> MN Environmental Cost Recovery Rider	1,356		See Note	1,356	
24	ISO Cost Recovery Trackers:					
25	MISO Schedule 26 and 26A Trans Cost Recovery Rider True-up	3,262,005	1,620,735	See Note	4,307,367	575,373
26	SPP Cost Recovery Rider	462,077	116,079	See Note	263,665	314,491
27	Deferred Rate Case Expenses:					
28	<sup>(b)</sup> MN Deferred Rate Case Expenses Subject to Recovery	1,508,373		407.4	377,093	1,131,280
29	<sup>(a)</sup> ND Deferred Rate Case Expenses Subject to Recovery	121,937		407.4	121,937	
30	<sup>(a)</sup> SD Deferred Rate Case Expenses Subject to Recovery	108,055		407.4	108,055	
31	Other:					
32	<sup>(a)</sup> ND Fuel Clause Adjustment		3,013,192	See Note	3,013,192	
33	<sup>(a)</sup> MN Fuel Clause Adjustment	2,068,704	12,544,929	See Note	4,671,152	9,942,481
34	<sup>(a)</sup> SD Fuel Clause Adjustment	368,077	1,382,530	See Note	800,371	950,236
35	Derivatives Marked-to-Market Losses		7,456,008	244	325,600	7,130,408
36	Property/Non Property Related Items		1,166,181	282	1,166,181	
37	See Footnote in Notes to Financial					
38	Statements for amortization periods.					
44	TOTAL	156,156,750	59,108,876		87,916,960	127,348,666

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: RM02-7-000
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017/M-21-811
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017-M-22-577
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017-M-22-174
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017/M-20-475; EL017/CIP-22-165
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: EL22-011
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: EL22-013
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017-M-21-382
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017/GR-20-719
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017/M-18-380
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017/M-16-374
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017/GR-20-719
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: PU-17-398
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: EL18-021
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Case No. PU-17-398
(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: E017/AA-20-462; E017/AA-21-311
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets Docket #: EL18-021
(r) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(s) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(t) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(u) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(v) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(w) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(x) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(y) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(z) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(aa) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445
(ab) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged Offsetting accounts used were 440, 442, 444, and 445

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**MISCELLANEOUS DEFERRED DEBITS (Account 186)**

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Conservation Improvement					
2	Programs - MN		16,309,413	182.3	16,309,413	
3	Energy Efficiency Program - SD		1,249,361	182.3	1,249,361	
4	Amortized Expenses	322,303	23,382	186.0	345,685	
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	322,303				

Name of Respondent: Otter Tail Power Company		This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
<b>ACCUMULATED DEFERRED INCOME TAXES (Account 190)</b>				
1. Report the information called for below concerning the respondent's accounting for deferred income taxes. 2. At Other (Specify), include deferrals relating to other income and deductions.				
Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	
1	Electric			
2	Property Insurance Reserve			
3	Workman's Compensation Reserve		208,563	225,189
4	Medical Insurance Reserve			
5	Injuries and Damages Reserve			
6	See Note Below		96,122,451	122,011,804
7	Other			
8	TOTAL Electric (Enter Total of lines 2 thru 7)		96,331,014	122,236,993
9	Gas			
15	Other			
16	TOTAL Gas (Enter Total of lines 10 thru 15)			
17.1	Other (Specify)			
17	Other (Specify)			
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)		96,331,014	122,236,993
<b>Notes</b>				

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

	BALANCE AT BEGIN OF YEAR	BALANCE AT END OF YEAR
Post Retirement Benefits	15,805,505	15,411,716
Executive Supplemental Pension	2,719,235	2,502,599
Reserve for Bad Debts	417,508	330,286
Performance Shares	269,877	221,977
Accrued Vacation Pay	1,205,186	1,178,892
Capitalized Int. on Construction	5,813,285	6,647,573
Post Employment Benefits	250,712	166,138
Bonus Incentive	676,847	667,964
Nonqualified Retirement Savings	440,152	421,890
Deferred Settlement	40,691	20,172
Federal NOL Carryforward	9,301,291	0
Reserve for Loan Pools	3,104	0
Capitalized A & G	755,539	624,385
Customer Rebates Capitalized	232,861	352,602
Asbestos Removal Costs Capitalized	0	37,359,597
Stock Incentives	80,724	71,317
Executive Restoration Plan	145,563	169,405
CIAC Capitalized	(1,039)	0
Unicap Adjustment	17,171	16,496
Medicare Part D	154,702	131,098
Flow-Through Items	(39,513)	(68,759)
State NOL Carryforward	3,577,565	169,921
Federal ITC - Solar	93,987	0
Wind Energy Income Tax Credits-ND	34,067,837	32,424,769
ASC 740 Unamortized ITC	389,444	357,604
ASC 740 Recognition of Regulatory Assets (Liab.)	750,237	2,319,795
Excess Accumulated Deferred Tax due to Federal Rate Change	(3,507,938)	(2,173,514)
Wind Production Tax Credit Deferral (Asset)	22,461,918	22,687,881
	<u>96,122,451</u>	<u>122,011,804</u>

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**CAPITAL STOCKS (Account 201 and 204)**

- Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
- Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
- Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
- The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
- State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
- Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock	50,000,000	5.00		100	500				
7	Total	50,000,000			100	500				
8	Preferred Stock (Account 204)									
9	Cumulative Preferred	1,500,000								
10	Cumulative Preference	1,000,000								
15	Total	2,500,000								
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2022-12-31	Year/Period of Report End of: 2022/ Q4
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**Other Paid-in Capital**

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

- a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
- b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	<b>Donations Received from Stockholders (Account 208)</b>	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	<b>Reduction in Par or Stated Value of Capital Stock (Account 209)</b>	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	<b>Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)</b>	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	<b>Miscellaneous Paid-In Capital (Account 211)</b>	
14	Beginning Balance Amount	586,988,966
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	50,000,000
16	Ending Balance Amount	636,988,966
17	<b>Historical Data - Other Paid in Capital</b>	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	636,988,966

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**CAPITAL STOCK EXPENSE (Account 214)**

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Shares	
2	Not applicable	
3	Cumulative Preferred Shares	
22	TOTAL	



32													
33	Subtotal												
33	TOTAL		777,000,000									747,000,000	31,656,650

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES**

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	79,974,186
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	1,721,023
6	Net Gain from Property Retirements	1,336,477
7	Miscellaneous Taxable Items	
8	Conservation Improvement Programs	(696,709)
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj.)	5,065,502
11	Provision for Reserves	7,268,435
12	Miscellaneous Unallowed Deductions	45,993,311
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	
16	Equity in Earnings of Subsidiaries	
17	Wind Rider Revenue	
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	93,063,759
21	Removal Costs	(13,059,827)
22	Charges to Reserves	11,115,835
23	Leveraged ESOP Deduction	1,277,513
24	Sec 481(a) Cap to Repair Basis Adjustments	
25	Miscellaneous Other Deductions	41,069,300
27	Federal Tax Net Income	7,195,650
28	Show Computation of Tax:	
29	Federal Tax (LINE 27 X 21%)	1,511,086
30	Tax (Credits) and Adjustments	(1,139,308)
31	Prior Period Adjustments	(22,690,919)
32	Transfer Net Operating Loss to Deferred Carryforward	
33	Total Federal Income Tax	(22,319,141)
34	Charged to Account 5410.1001	(22,875,139)
35	Charged to Account 5410.2001	555,999
36	Charged to Account 5410.4120	
37	<sup>(a)</sup> Total	(22,319,140)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: ComputationOfTaxDescription

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME  
FOR FEDERAL INCOME TAXES (Continued)

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2022. The other members of the affiliated group and their respective federal income tax provisions are as follows:

Otter Tail Corporation	-4,693,566
Varistar Corporation	-2,329
BTD Manufacturing, Inc.	3,076,080
Northern Pipe Products, Inc.	25,966,641
Vinyltech Corporation	29,802,282
T. O. Plastics, Inc.	1,355,002
Otter Tail Assurance Limited	196,255
Total	55,700,365

The consolidated federal income tax liability is allocated on a separate return basis pursuant to the current tax sharing agreements between Otter Tail Corporation and the subsidiaries.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR**

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot-note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)	
1		Income Tax			1		1,505,094	1,133,315		371,780		(22,875,139)				24,380,233 <sup>(b)</sup>
2		Unemployment Tax			706		34,815	34,697		824						34,815 <sup>(b)</sup>
3		Federal Insurance Tax					5,589,111	5,589,111								5,589,111 <sup>(b)</sup>
4	<b>Subtotal Federal Tax</b>				707		7,129,020	6,757,123		372,604		(22,875,139)				30,004,159
5		Property Tax	Minnesota		10,397,281		10,014,575	10,294,506		10,117,350		10,014,575				
6		Income Tax	Minnesota				169,922	169,921		1		(2,331,735)				2,501,657 <sup>(b)</sup>
7		Unemployment Tax	Minnesota		1,106		81,128	72,598		9,636						81,128 <sup>(b)</sup>
8		Property Tax	North Dakota		3,420,680		4,553,888	4,187,744		3,786,824		4,546,040				7,848 <sup>(b)</sup>
9		Income Tax	North Dakota				116,701	116,699		2		(1,672,411)				1,789,112 <sup>(b)</sup>
10		Unemployment Tax	North Dakota		195		14,930	14,408		717						14,930 <sup>(b)</sup>
11		Other Taxes and Fees	North Dakota		25,503		105,378	104,828		26,053		105,378				
12		Property Tax	South Dakota		3,120,022		3,067,836	3,125,690		3,062,168		3,067,836				
13		Unemployment Tax	South Dakota		133		7,029	7,076		86						7,029 <sup>(b)</sup>
14		Income Tax	Other													
15		Unemployment Tax	Other		974		3,674	5,233		(585)						3,674 <sup>(b)</sup>
16		Other Taxes and Fees	Other		2,964		1,611	4,427		148						1,611 <sup>(b)</sup>
17	<b>Subtotal State Tax</b>				16,968,858		18,136,672	18,103,130		17,002,400		13,729,683				4,406,989
40	<b>TOTAL</b>				16,969,565		25,265,692	24,860,253		17,375,004		(9,145,456)				34,411,148

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: TaxesIncurredOther
Account 409.2: 555,999 Other 23,824,234
(b) Concept: TaxesIncurredOther
Account 184: 34,815
(c) Concept: TaxesIncurredOther
Account 184: 5,589,111
(d) Concept: TaxesIncurredOther
Account 409.2: 125,266 Other 2,376,391
(e) Concept: TaxesIncurredOther
Account 184: 81,128
(f) Concept: TaxesIncurredOther
Account 408.2: 7,848
(g) Concept: TaxesIncurredOther
Account 409.2: 44,106 Other 1,745,006
(h) Concept: TaxesIncurredOther
Account 184: 14,930
(i) Concept: TaxesIncurredOther
Account 184: 7,029
(j) Concept: TaxesIncurredOther
Account 184: 3,674
(k) Concept: TaxesIncurredOther
Account 151: 1,611

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)**

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%	16,570,226	190.0		411.4	741,860		15,828,366	35 years	
3	4%								—	
4	7%								—	
5	10%		411.4		411.4				—	
6	30%	90,405	190.0		411.4	2,663		87,742	35 years	
7									—	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	16,660,631				744,523		15,916,108		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10									—	
47	OTHER TOTAL									
48	GRAND TOTAL	16,660,631						15,916,108		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**OTHER DEFERRED CREDITS (Account 253)**

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Prepaid Electric Revenue	1,446,008	456	1,106,201	1,458,569	1,798,376
2	Asset Reclass	262,769	184		354,247	617,016
3	ASC 842 Leases	141,620	173	2,016	8,851	148,455
4	Deferred Revenue	118,331	456	33,333		84,998
47	TOTAL	1,968,728		1,141,550	1,821,667	2,648,845

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**ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)**

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities								0		
4	Pollution Control Facilities	8,408,032	2,219,939						254	1,750	10,629,721
5	Other										
5.1						0			0		
5.2	Other (provide details in footnote):								0		
8	TOTAL Electric (Enter Total of lines 3 thru 7)	8,408,032	2,219,939							1,750	10,629,721
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1						0			0		
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	8,408,032	2,219,939							1,750	10,629,721
18	Classification of TOTAL										
19	Federal Income Tax	6,149,334	1,674,674					0		0	7,825,758
20	State Income Tax	2,258,698	545,265					0		0	2,803,963
21	Local Income Tax							0		0	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)**

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	221,367,931	29,114,815	7,255,398	26,125	254		182.3	36,184,964	279,386,187	
3	Gas					0		0			
4	Other (Specify)					0		0			
5	Total (Total of lines 2 thru 4)	221,367,931	29,114,815	7,255,398	26,125				36,184,964	279,386,187	
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	221,367,931	29,114,815	7,255,398	26,125				36,184,964	279,386,187	
10	Classification of TOTAL										
11	Federal Income Tax	164,398,569	21,567,597	5,236,012	19,708				30,355,566	211,066,012	
12	State Income Tax	56,969,362	7,547,218	2,019,386	6,417				5,829,398	68,320,175	
13	Local Income Tax										

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Amort of Loss on Recquired Debt (pre holdco)	59,608
Deferred HLP Cost Recovery	(346,220)
South Dakota Flow Thru-Overheads	(47,993)
Prepaid Expenses	658,475
ADR Repair Allowance	1,282,874
Sec 162 & 174 R&D Deduction	1,924,807
Highway Reimbursements	522,823
AFUDC on Debt	3,941,942
Capitalized Overheads	(777,408)
Repairs Deduction - Basis Adjustments	5,059,129
Sec 481(a) Cap to Repair Basis Adjustments (PY)	(3,957,256)
Excess Tax over book Depreciation	299,139,123
North Dakota Investment Tax Credit - Federal Impacts	6,111,168
Excess Accumulated Deferred Tax due to Federal Rate Change	(34,946,272)
ASC 740 (SFAS 109) ADIT Credits - Property	761,387
	279,386,187

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)**

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Other Utility Operations	25,629,820	(7,734,333)	(5,081,285)	453	450			<sup>(b)</sup> See Note	1,248,917	24,225,692
4	<sup>(b)</sup> Nonutility & Other	3,155,454			827,629	646,172					3,336,911
9	TOTAL Electric (Total of lines 3 thru 8)	28,785,274	(7,734,333)	(5,081,285)	828,082	646,622				1,248,917	<sup>(b)</sup> 27,562,603
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	28,785,274	(7,734,333)	(5,081,285)	828,082	646,622				1,248,917	27,562,603
20	Classification of TOTAL										
21	Federal Income Tax	19,269,106	(5,829,912)	(3,654,755)	624,928	487,826				922,010	18,153,061
22	State Income Tax	9,516,168	(1,904,421)	(1,426,530)	203,154	158,796				326,907	9,409,542
23	Local Income Tax										
NOTES											

FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Deferred taxes related to CIP costs

(b) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherDescriptionOfCreditedAccountNumber

Adjustment related to ASC 740 and excess accumulated deferred tax due to federal rate change

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Pensions	24,805,084
Conservation Improvement Program - MN & SD - Net (BTL)	3,336,910
Rate Rider Mechanism	-1,227,796
ND Rate Case Expenses	-1
MN Rate Case Expenses	297,963
Deferred State NOL's - Fed Haircut	35,683
Regulatory Adjustments - JE 820 ESSRP	-362,297
Excess Accumulated Deferred Tax due to Federal Rate Change	-772,384
ASC 740 (SFAS 109) ADIT Credits - Non-Property	1,469,441
	27,562,603

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**OTHER REGULATORY LIABILITIES (Account 254)**

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Deferred Income Taxes:					
2	ASC 740	1,014,152	190	1,638,230	1,070,661	446,583
3	<sup>(a)</sup> ADIT Legacy Reclass	128,423,106	See Note <sup>(a)</sup>	2,671,907	5,282,426	131,033,625
4	Post-retirement Benefit Plans:					
5	<sup>(a)</sup> ND Post Retirement Medical Benefits Adjustment	2,603,390			2,986,045	5,589,435
6	Fuel Clause Adjustment:					
7	<sup>(a)</sup> MN Refundable Fuel Clause Adj Revenue	1,553,997	See Note <sup>(a)</sup>	1,888,554	334,557	
8	<sup>(a)</sup> ND Refundable Fuel Clause Adj Revenues		See Note <sup>(a)</sup>	7,170,065	7,535,520	365,455
9	<sup>(a)</sup> SD Refundable Fuel Clause Adj Revenues		See Note <sup>(a)</sup>	516,681	516,681	
10	Alternative Revenue Program Riders:					
11	<sup>(a)</sup> ND Transmission Cost Recovery Rider Accrued Refund	679,955	See Note <sup>(a)</sup>	565,878	132,501	246,578
12	<sup>(a)</sup> SD Transmission Cost Recovery Rider Accrued Refund	273,054	See Note <sup>(a)</sup>	153,171	25,224	145,107
13	<sup>(a)</sup> ND Renewable Resource Rider Accrued Revenues	4,424,568	See Note <sup>(a)</sup>	1,834,257	5,158,087	7,748,398
14	<sup>(a)</sup> SD Phase-in Rider	1,456,313	See Note <sup>(a)</sup>	1,546,893	126,580	36,000
15	<sup>(a)</sup> ND Generation Cost Recovery Rider	299,636	See Note <sup>(a)</sup>	65,538	698,905	933,003
16	<sup>(a)</sup> MN Renewable Resource Rider Accrued Revenues	1,974,132	See Note <sup>(a)</sup>	2,630,171	656,039	
17	<sup>(a)</sup> MN EITE Cost Recovery Rider	41,463	See Note <sup>(a)</sup>	181,347	282,951	143,067
18	<sup>(a)</sup> SD Phase-in for AMI				103,827	103,827
19	<sup>(a)</sup> MN Decoupling		See Note <sup>(a)</sup>	743,441	998,255	254,814
20	<sup>(a)</sup> MN Uplift Program Rider				184,192	184,192
21	<sup>(a)</sup> MN EUIC Rider for AMI		See Note <sup>(a)</sup>		171,807	171,807
22	ISO Cost Recovery Trackers:					
23	<sup>(a)</sup> MISO Schedule 26 and 26A Accrual	348,431	407.4	585,317	251,729	14,843
24	Other:					
25	MN portion of gain on sale of Wahpeton	66,916	407.4	5,577		61,339
26	Derivatives Marked-to-Market Gains	6,213,576	254	8,626,176	2,412,600	
27	<sup>(a)</sup> MN Credit Card Fees Tracker				77,722	77,722
28	See Footnote in Notes to Financial					
29	Statements for amortization periods.					
41	TOTAL	149,372,689		30,823,203	29,006,309	147,555,795

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: PU-17-398; EL18-021; E.G-999/CI-17-895
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: PU-17-398
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017/AA-21-311
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: PU-17-398
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: EL18-021
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: PU-22-335
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: EL21-031
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: PU-22-429
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: EL22-013
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: PU-23-083
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017-M-22-577
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017-M-22-174
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: EL22-013
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017/GR-20-719
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017-M-22-133
(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017/M-21-382
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017/M-16-374
(r) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities Docket #: E017/GR-20-719
(s) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 182.3, 282, 283, and 190
(t) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(u) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(v) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(w) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(x) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(y) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(z) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(aa) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(ab) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(ac) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(ad) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.
(ae) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment Offsetting accounts were 440, 442, 444, and 445.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**Electric Operating Revenues**

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	143,944,888	137,271,563	1,309,247	1,241,949	104,894	104,287
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	<sup>(a)</sup> 100,593,238	100,900,353	1,009,145	947,183	27,059	28,219
5	Large (or Ind.) (See Instr. 4)	<sup>(a)</sup> 218,147,823	168,781,383	3,215,048	2,542,162	845	14
6	(444) Public Street and Highway Lighting	4,130,806	4,160,797	15,283	16,212	656	659
7	(445) Other Sales to Public Authorities	3,789,097	3,643,467	43,645	42,373	1,247	1,245
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	470,605,852	414,757,563	5,592,368	4,789,879	134,701	134,424
11	(447) Sales for Resale	18,538,975	17,936,389	277,830	460,123		
12	TOTAL Sales of Electricity	489,144,827	432,693,952	5,870,198	5,250,002	134,701	134,424
13	(Less) (449.1) Provision for Rate Refunds	2,788,067	12,478,829				
14	TOTAL Revenues Before Prov. for Refunds	486,356,760	420,215,123	5,870,198	5,250,002	134,701	134,424
15	Other Operating Revenues						
16	(450) Forfeited Discounts	800,374	614,409				
17	(451) Miscellaneous Service Revenues	<sup>(a)</sup> 364,482	367,635				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	945,169	745,160				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	<sup>(a)</sup> 5,500,001	5,873,993				
22	(456.1) Revenues from Transmission of Electricity of Others	51,507,712	48,240,133				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	59,117,738	55,841,330				
27	TOTAL Electric Operating Revenues	545,474,498	476,056,453				

Line12, column (b) includes \$(2,073,373) of unbilled revenues.  
Line12, column (d) includes (20,322) MWH relating to unbilled revenues

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Small (or Commercial) includes all customers having a demand of less than 1000 kw.

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Large (or Industrial) includes all customers having a demand exceeding 1000 kw.

(c) Concept: MiscellaneousServiceRevenues

Description of Revenue	Q4 2022	Q4 2021
All others (under \$250,000 each)	364,482	367,635
Total	364,482	367,635

(d) Concept: OtherElectricRevenue

Description of Revenue	Q4 2022	Q4 2021
Sale of steam	3,645,657	882,961
Load Control & Dispatch	1,587,594	1,427,950
Service Extension Agreement Revenues	—	2,797,163
Renewable Energy RECs Generated	—	64,228
All others (under \$250,000 each)	266,750	701,691
Total	5,500,001	5,873,993

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)**

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable				
46	TOTAL				

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential - 440					
2	Residential Service 9.01	939,645	116,143,210	104,894	8,958	0.1236
3	Residential Service 9.02 (Cntrl Demand)	137,765	14,709,096	4,396	31,339	0.1068
4	Air Conditioning Control Rider		(71,684)	571		
5	Controlled Service - Deferred Load	13,517	1,149,594	813	16,626	0.0850
6	Controlled Service - Interruptible Load 14.04	281	17,158	7	40,083	0.0612
7	Controlled Service - Interruptible Load 14.05	177,053	11,219,563	9,097	19,463	0.0634
8	Fixed Time of Delivery Service 14.07	6,408	357,503	354	18,102	0.0558
9	Off-Peak Electric Vehicle Rider 14.12	57	4,550	11	5,207	0.0794
10	LED Street and Area Lighting 11.07	578	336,996	1,699	340	0.5827
11	Outdoor Lighting 11.04	1,638	287,023	1,422	1,152	0.1752
12	Outdoor Lighting - Energy Only 11.03	122	10,621	18	6,760	0.0873
13	Small Power Producer Rider 12.01		890	44		
14	Voluntary Renewable Energy Rider 14.09		24,303	181		
15	Water Heating - Cntrl Service (Off-Peak) 14.01	31,982	2,989,079	11,551	2,769	0.0935
16	Other	1,507	38,004			
17	Residential - 440 Sales			=(30,164)		
41	TOTAL Billed Residential Sales	1,310,553	147,215,906	104,894	12,494	0.1123
42	TOTAL Unbilled Rev. (See Instr. 6)	(1,306)	(3,271,018)			(0.0116)
43	TOTAL	1,309,247	143,944,888	104,894	12,482	0.1099

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: AverageNumberOfCustomersPerMonthResidentialSalesBilled

Average number of customers are included in Residential Service 9.01 Rate Schedule.

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial & Industrial (Small) - 442					
2	Commercial (Small)					
3	Air Conditioning Control Rider 14.08		(14,968)	27	(554)	
4	Commercial Time-of-Use 10.03	4,321	403,684	15	26,912	0.0934
5	Controlled Service - Deferred Load 14.06	21,798	1,500,974	477	3,147	0.0689
6	Controlled Service - Interruptible Load 14.04	56,640	3,057,323	266	11,494	0.0540
7	Controlled Service - Interruptible Load 14.05	63,602	3,626,420	2,031	1,786	0.0570
8	EV DCFE General Service - Time of Day 10.07	48	5,057	1	5,057	0.1051
9	Farm Service 9.03	68,251	7,699,878	2,704	2,848	0.1128
10	Fire Sirens 11.06		684	8	85	
11	Fixed Time of Delivery Service 14.07	24,390	1,283,036	461	2,783	0.0526
12	General Service 10.01	217,221	26,903,182	19,699	1,366	0.1239
13	General Service 10.02	527,196	57,847,156	4,657	12,424	0.1097
14	Irrigation Service 11.02	6,998	704,860	126	5,594	0.1007
15	Municipal Pumping Service 11.05	7	625	1	625	0.0835
16	Off-Peak Electric Vehicle Rider 14.12	12	1,135	1	1,135	0.0917
17	LED Street and Area Lighting 11.07	2,610	1,192,650	1,884	633	
18	Outdoor Lighting 11.04	4,741	749,937	1,519	494	0.1582
19	Outdoor Lighting - Energy Only 11.03	1,693	173,364	250	693	0.1024
20	Residential Service 9.01	949	109,270	45	2,428	0.1152
21	Residential Service-Controlled Demand 9.02	1,047	103,001	24	4,292	0.0984
22	Small Power Producer Rider 12.01		1,339	34	39	
23	Voluntary Renewable Energy Rider 14.09		8,816	20	441	
24	Water Heating - Cntld Service (Off-Peak) 14.01	1,604	123,759	355	349	0.0771
25	Other	(405)	(54,472)			0.1345
26	Commercial (Small) & Industrial-442			<sup>(b)</sup> (7,546)		
41	TOTAL Billed Small or Commercial	1,002,723	105,426,710			
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	6,422	(4,833,472)			
43	TOTAL Small or Commercial	1,009,145	<sup>(b)</sup> 100,593,238	27,059	37,294	0.0997

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercialBilled

Average number of customers are included in Commercial General Rate Schedule 10.01 and 10.02.

(b) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Small (or Commercial) includes all customers having a demand of less than 1000 kw.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial & Industrial (Large) - 442					
2	Commercial (Large)					
3	Air Conditioning Control Rider 14.08		(5,987)			
4	Commercial Time-of-Use 10.03	1,083,338	92,341,891	10	9,234,189	0.0852
5	Commercial Time-of-Use 10.04	38	14,023	844	17	0.3672
6	Controlled Service - Deferred Load 14.06	3,730	216,623	8	27,078	0.0581
7	Controlled Service - Interruptible Load 14.04	51,644	2,655,329	49	54,190	0.0514
8	Controlled Service - Interruptible Load 14.05	2,170	105,212	18	5,845	0.0485
9	Fixed Time of Delivery Service 14.07	2,441	110,962	19	5,840	0.0455
10	General Service 10.01	27,180	2,918,471	70	41,692	0.1074
11	General Service 10.02	38	4,366	60	73	0.1161
12	Large General Service - Time of Day 10.05	1,141,573	76,023,001	25	3,040,920	0.0666
13	Large General Service Rider 14.03	278,380	14,107,873	7	2,015,410	0.0507
14	LED Street and Area Lighting 11.07	588	248,296	112	2,217	0.4225
15	Outdoor Lighting 11.04	680	115,668	56	2,066	0.1702
16	Outdoor Lighting - Energy Only 11.03	177	17,524	16	1,095	0.0989
17	Real Time Pricing Rider	74,028	4,136,125			0.0559
18	Small Power Producer Rider 12.01		83	3	28	
19	Small Power Producer Rider 12.02		16	1	16	
20	Small Power Producer Rider 12.03		15			
21	Standby Service - Option A Firm 11.01	141	17,426			0.1240
22	Super Large General Service 10.06	533,995	24,561,865	1	24,561,865	0.0460
23	Voluntary Renewable Energy Rider 14.09		29,283	3	9,761	
24	Water Heating - Cntrld Service (Off-Peak) 14.01	129	7,266	2	3,633	0.0562
25	Other	(405)	(54,472)			0.1345
26	Commercial (Large) & Industrial - 442			<sup>(b)</sup> (459)		
41	TOTAL Billed Large (or Ind.) Sales	3,199,865	217,570,859			
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	15,183	576,964			
43	TOTAL Large (or Ind.)	3,215,048	<sup>(b)</sup> 218,147,823	845		

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrialBilled

Average number of customers are included in Commercial General Rate Schedule 10.01 and 10.02.

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Large (or Industrial) includes all customers having a demand exceeding 1000 kw.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

- Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
- Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
- Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
- The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
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40						
41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Streetlighting - 444					
2	LED Street and Area Lighting 11.07	4,106	2,503,916	249	10,096	0.6098
3	Outdoor Lighting 11.04	6,326	1,155,498	171	6,757	0.1827
4	Outdoor Lighting - Energy Only 11.03	5,051	470,675	236	1,994	0.0932
5	Adjustment	(289)	(182,146)			0.6305
41	TOTAL Billed Public Street and Highway Lighting	15,194	3,947,943	656	23,162	0.2598
42	TOTAL Unbilled Rev. (See Instr. 6)	89	182,863			0.1749
43	TOTAL	15,283	4,130,806	656	23,297	0.2703

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Other Public Authority-445					
2	Controlled Service - Deferred Load 14.06	74	5,829	1	73,879	0.0789
3	Controlled Service - Interruptible Load 14.04	540	27,115	4	6,779	0.0502
4	Controlled Service - Interruptible Load 14.05	259	14,668	8	1,834	0.0566
5	Fire Sirens 11.06		10,131	102	99	
6	Fixed Time of Delivery Service 14.07	40	2,055	3	685	0.0513
7	General Service 10.01	146	19,987	16	1,249	0.1367
8	General Service 10.02	224	28,303	3	9,434	0.1265
9	Municipal Pumping Service 11.05	42,344	3,795,102	1,145	3,315	0.0896
10	LED Street and Area Lighting 11.07	3	2,249	4	562	0.7093
11	Outdoor Lighting 11.04	1	125	6	21	0.2360
12	Outdoor Lighting - Energy Only 11.03	36	3,388	5	678	0.0954
13	Other	46	5,857			0.1272
14	Other Public Authority-445 Sales			14(50)		
41	TOTAL Billed Other Sales to Public Authorities	43,713	3,914,809	1,247	35,055	0.0896
42	TOTAL Unbilled Rev. (See Instr. 6)	(68)	(125,712)			(0.1314)
43	TOTAL	43,645	3,789,097	1,247	35,000	0.0868

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: AverageNumberOfCustomersPerMonthOtherSalesToPublicAuthoritiesBilled

Average number of customers are include in Rate Schedules General Service 10.01 and 10.02 and Municipal Pumping Service 11.05.

**FERC FORM NO. 1 (ED. 12-95)**

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Revenue from Fuel Adjustment					
2	Clause is reported in footnote.					
3	Provision for Rate Refunds MN		2,788,067			
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		2,788,067			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

The following revenue received through the fuel clause adjustment is included in the amounts reported on pages 304-304.3.

Residential - 440		
Controlled Service - Deferred Load	14.06	\$332,914
Controlled Service - Interruptible Load	14.04	\$8,159
	14.05	\$4,946,908
Fixed Time of Delivery Service	14.07	\$158,444
Off-Peak Electric Vehicle Rider	14.12	\$1,228
LED Street and Area Lighting	11.07	\$11,665
Outdoor Lighting	11.04	\$34,030
Outdoor Lighting - Energy Only	11.03	\$2,331
Residential Service	9.01	\$24,613,877
Residential Service-Controlled Demand	9.02	\$3,770,500
Water Heating - Controlled Service (Off-Peak)	14.01	\$819,352
	<b>Total Residential</b>	<b>\$34,699,407</b>
Commercial and industrial - 442		
Commercial Time-of-Use	10.03	\$27,139,489
	10.04	\$970
Controlled Service - Deferred Load	14.06	\$676,021
Controlled Service - Interruptible Load	14.04	\$3,086,136
	14.05	\$1,856,114
EV DCFC General Service - Time of Day	10.07	\$1,138
Farm Service	9.03	\$1,771,534
Fixed Time of Delivery Service	14.07	\$682,262
General Service	10.01	\$6,379,912
	10.02	\$14,095,030
Irrigation Service	11.02	\$143,779
Large General Service - Time of Day	10.05	\$24,280,611
Large General Service Rider	14.03	\$2,002,437
Municipal Pumping Service	11.05	\$265
Off-Peak Electric Vehicle Rider	14.12	\$299
LED Street and Area Lighting	11.07	\$65,056
Outdoor Lighting	11.04	\$112,757
Outdoor Lighting - Energy Only	11.03	\$37,890
Residential Service	9.01	\$25,191
Residential Service-Controlled Demand	9.02	\$28,632
Standby Service - Option A Firm	11.01	\$3,648
Super Large General Service	10.06	\$14,691,620
Water Heating - Controlled Service (Off-Peak)	14.01	\$44,340
Other		\$4,822
	<b>Total Commercial and industrial</b>	<b>\$97,129,954</b>
Streetlighting		
LED Street and Area Lighting	11.07	\$63,891
Outdoor Lighting	11.04	\$135,288
Outdoor Lighting - Energy Only	11.03	\$98,919
	<b>Total Streetlighting</b>	<b>\$318,098</b>
Other public authority - 445		
Controlled Service - Deferred Load	14.06	\$1,615
Controlled Service - Interruptible Load	14.04	\$14,195
	14.05	\$6,673
Fixed Time of Delivery Service	14.07	\$1,018
General Service	10.01	\$3,663
	10.02	\$5,836
Municipal Pumping Service	11.05	\$1,065,338
LED Street and Area Lighting	11.07	\$63
Outdoor Lighting	11.04	\$284
Outdoor Lighting - Energy Only	11.03	\$707
	<b>Total Other public authority</b>	<b>\$1,099,392</b>
	<b>TOTAL Billed FCA Revenue</b>	<b>\$133,246,851</b>

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES OF ELECTRICITY BY RATE SCHEDULES**

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	5,572,048	478,076,227	134,701	41,366	0.0858
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	20,320	(7,470,375)			(0.3676)
43	TOTAL - All Accounts	5,592,368	470,605,852	134,701	41,517	0.0842

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SALES FOR RESALE (Account 447)**

- Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
- Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

- Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
- In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
- For requirements RQ sales and any type-of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
- The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	RQ SALES										
2	Badger, SD	RQ	144	0.26			397	13,577	13,369	<sup>18</sup> 5,398	32,344
3	Newfolden, MN	RQ	174	0.39			2,178	20,405	73,259	<sup>18</sup> 28,878	122,542
4	Nielsenville, MN	RQ	175	0.01			75	497	2,593	<sup>18</sup> 957	4,047
5	Shelly, MN	RQ	176	0.22			728	15,427	26,267	<sup>18</sup> 10,432	52,126
6	NON-RQ SALES										
7	Midwest ISO Energy Market	OS	V9				274,452		18,327,916		18,327,916
15	Subtotal - RQ						3,378	49,906	115,488	45,665	211,059
16	Subtotal-Non-RQ						274,452		18,327,916		18,327,916
17	Total						277,830	49,906	18,443,404	45,665	18,538,975

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges
(b) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges
(c) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges
(d) Concept: OtherChargesRevenueSalesForResale
Fuel Adjustment Charges

Name of Respondent: Otter Tail Power Company		This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
<b>ELECTRIC OPERATION AND MAINTENANCE EXPENSES</b>				
If the amount for previous year is not derived from previously reported figures, explain in footnote.				
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)	
1	1. POWER PRODUCTION EXPENSES			
2	A. Steam Power Generation			
3	Operation			
4	(500) Operation Supervision and Engineering	1,446,943	1,541,992	
5	(501) Fuel	44,772,884	42,221,797	
6	(502) Steam Expenses	5,654,992	5,071,833	
7	(503) Steam from Other Sources			
8	(Less) (504) Steam Transferred-Cr.			
9	(505) Electric Expenses	1,776,145	2,170,528	
10	(506) Miscellaneous Steam Power Expenses	4,471,713	3,837,213	
11	(507) Rents	(5,533)	16,476	
12	(509) Allowances	181	75	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	58,117,325	54,859,914	
14	Maintenance			
15	(510) Maintenance Supervision and Engineering	624,662	798,606	
16	(511) Maintenance of Structures	795,762	874,500	
17	(512) Maintenance of Boiler Plant	6,980,241	6,229,229	
18	(513) Maintenance of Electric Plant	2,866,936	2,714,136	
19	(514) Maintenance of Miscellaneous Steam Plant	941,350	921,925	
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,208,951	11,538,396	
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	70,326,276	66,398,310	
22	B. Nuclear Power Generation			
23	Operation			
24	(517) Operation Supervision and Engineering			
25	(518) Fuel			
26	(519) Coolants and Water			
27	(520) Steam Expenses			
28	(521) Steam from Other Sources			
29	(Less) (522) Steam Transferred-Cr.			
30	(523) Electric Expenses			
31	(524) Miscellaneous Nuclear Power Expenses			
32	(525) Rents			
33	TOTAL Operation (Enter Total of lines 24 thru 32)			
34	Maintenance			
35	(528) Maintenance Supervision and Engineering			
36	(529) Maintenance of Structures			
37	(530) Maintenance of Reactor Plant Equipment			
38	(531) Maintenance of Electric Plant			
39	(532) Maintenance of Miscellaneous Nuclear Plant			
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)			
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 & 40)			
42	C. Hydraulic Power Generation			
43	Operation			
44	(535) Operation Supervision and Engineering	51,177	14,248	
45	(536) Water for Power			
46	(537) Hydraulic Expenses	8,156	12,973	
47	(538) Electric Expenses	860	3,347	
48	(539) Miscellaneous Hydraulic Power Generation Expenses	35,808	10,127	

49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	96,001	40,695
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	345	323
54	(542) Maintenance of Structures	26,644	1,881
55	(543) Maintenance of Reservoirs, Dams, and Waterways	265,138	249,940
56	(544) Maintenance of Electric Plant	18,437	3,289
57	(545) Maintenance of Miscellaneous Hydraulic Plant	718	3,512
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	311,282	258,945
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	407,283	299,640
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	498,816	335,645
63	(547) Fuel	20,578,473	17,434,621
64	(548) Generation Expenses	2,650,988	2,289,126
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	2,211,236	1,165,502
66	(550) Rents	1,451,522	1,327,200
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	27,391,035	22,552,094
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	25,834	15,715
70	(552) Maintenance of Structures	77,501	30,733
71	(553) Maintenance of Generating and Electric Plant	4,736,562	3,916,485
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	392,863	556,435
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	5,232,760	4,519,368
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	32,623,795	27,071,462
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	100,281,054	65,408,578
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	431,659	435,472
78	(557) Other Expenses	42,138	33,508
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	100,754,851	65,877,558
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	204,112,205	159,646,970
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	249,664	293,431
85	(561.1) Load Dispatch-Reliability	84,388	72,510
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,441,069	2,269,473
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,211,833	1,032,549
89	(561.5) Reliability, Planning and Standards Development	531,719	630,464
90	(561.6) Transmission Service Studies	80,983	30,857
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	395,015	391,997
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	783,176	696,867
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	23,764,287	21,238,608
97	(566) Miscellaneous Transmission Expenses	2,174,930	942,084
98	(567) Rents	37,445	43,368
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	31,754,509	27,642,208
100	Maintenance		

101	(568) Maintenance Supervision and Engineering	288,580	240,930
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	18,138	50,747
104	(569.2) Maintenance of Computer Software	825,411	849,512
105	(569.3) Maintenance of Communication Equipment	63,034	86,300
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,471,875	1,278,120
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	2,019,929	1,175,440
109	(572) Maintenance of Underground Lines	1,133	138
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	4,688,100	3,681,187
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	36,442,609	31,323,395
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	770,030	855,377
117	(575.3) Transmission Rights Market Facilitation	5,083	1,618
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	25,025	28,487
120	(575.6) Market Monitoring and Compliance	228	1,006
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	800,366	886,488
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	247,043	229,437
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	247,043	229,437
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	1,047,409	1,115,925
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	314,772	268,762
135	(581) Load Dispatching	281,414	247,976
136	(582) Station Expenses	332,859	315,956
137	(583) Overhead Line Expenses	232,250	318,962
138	(584) Underground Line Expenses	1,806,839	2,276,233
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	611	
140	(586) Meter Expenses	888,210	1,029,700
141	(587) Customer Installations Expenses	7,532	14,241
142	(588) Miscellaneous Expenses	3,701,612	3,798,371
143	(589) Rents	194,724	188,397
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	7,760,823	8,458,598
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	627,121	1,047,513
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	598,486	752,558
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	6,068,194	4,604,634
150	(594) Maintenance of Underground Lines	811,407	875,121
151	(595) Maintenance of Line Transformers	184,714	158,087

152	(596) Maintenance of Street Lighting and Signal Systems	166,109	199,540
153	(597) Maintenance of Meters	950,342	869,209
154	(598) Maintenance of Miscellaneous Distribution Plant	136,501	157,814
155	TOTAL Maintenance (Total of Lines 146 thru 154)	9,542,874	8,664,476
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	17,303,697	17,123,074
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	31,226	21,641
160	(902) Meter Reading Expenses	6,048,973	6,093,420
161	(903) Customer Records and Collection Expenses	6,398,080	5,654,253
162	(904) Uncollectible Accounts	696,382	10,999
163	(905) Miscellaneous Customer Accounts Expenses	850,853	499,048
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	14,025,514	12,279,361
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	745,699	700,345
168	(908) Customer Assistance Expenses	9,890,948	11,950,039
169	(909) Informational and Instructional Expenses	98,070	91,078
170	(910) Miscellaneous Customer Service and Informational Expenses	131,916	51,080
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	10,866,633	12,792,542
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	14,113	10,308
175	(912) Demonstrating and Selling Expenses	572,597	318,261
176	(913) Advertising Expenses	252	948
177	(916) Miscellaneous Sales Expenses	5,738	5,163
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	592,700	334,680
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	28,959,962	25,968,814
182	(921) Office Supplies and Expenses	13,152,813	9,788,083
183	(Less) (922) Administrative Expenses Transferred-Credit	2,667,481	2,861,146
184	(923) Outside Services Employed	1,899,948	1,952,692
185	(924) Property Insurance	2,411,400	2,402,629
186	(925) Injuries and Damages	2,758,678	2,459,973
187	(926) Employee Pensions and Benefits	1,257,829	1,187,386
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,824,155	5,135,059
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	985,974	632,495
192	(930.2) Miscellaneous General Expenses	1,290,658	1,319,045
193	(931) Rents	330,177	278,359
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	53,204,113	48,263,389
195	Maintenance		
196	(935) Maintenance of General Plant	4,405,340	2,374,630
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	57,609,453	50,638,019
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	342,000,220	285,253,966

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: LoadDispatchMonitorAndOperateTransmissionSystem

\$595,728 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

(b) Concept: LoadDispatchMonitorAndOperateTransmissionSystem

\$657,224 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**PURCHASED POWER (Account 555)**

- Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
- Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
  - RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
  - LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
  - IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.
  - SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.
  - LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.
  - IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.
  - EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.
  - OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.
  - AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
- In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
- Report in column (g) the megawatt-hours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatt-hours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatt-hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
- Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
- The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
1	Rainbow Energy Marketing Corp	SF					22,800					2,556,964		2,556,964
2	Manitoba Hydro	SF					16,800					290,296		290,296
3	DTE Energy	SF					7,200					710,954		710,954
4	Minnkota Power Cooperative	SF					279,000					(4,531,303)		(4,531,303)
5	Western Area Power Administration	EX					(978)					(51,463)		(51,463)
6	Western Area Power Administration - WEC	OS					28,534					684,827		684,827
7	Beltrami Electric Cooperative	RQ					98,309				1,726,097	4,381,034	496,916	6,176,047
8	Nodak Rural Electric Cooperative	RQ					1,409				54,847	92,733		147,580
9	PKM Electric Cooperative	RQ					4,521				103,460	253,548		357,008
10	Red Lake Rural Electric Cooperative	RQ					2,786				64,930	132,715		197,645
11	Cass County Electric Cooperative	OS					89				461	16,791		17,252
12	Whetstone Valley Electric Cooperative	OS									1,035			1,035
13	City of Detroit Lakes	OS					926				1,126	1,389		2,515
14	Kindred School	RQ					0				51,000			51,000
15	Stevens Community Medical	RQ					0				28,800			28,800
16	SLB Milbank, LLC	RQ					0				25,200			25,200
17	American Crystal Sugar	OS					28					280		280
18	Hendricks Wind I	RQ					1,183					25,557		25,557
19	Borderline Wind	RQ					1,800					53,996		53,996
20	University of MN - Morris	RQ					4,842					254,225		254,225

21	Turtle Mountain Community College	RQ					7					163		163
22	Lake Region State College	RQ					1,518					48,819		48,819
23	conEdison Development RLF Community Hybrid, LLC	RQ					19,643					687,881		687,881
24	FPL Energy ND Wind II, LLC	RQ					49,507					1,480,247		1,480,247
25	Langdon Wind, LLC	RQ					66,775					2,885,992		2,885,992
26	Langdon Wind, LLC - Curtailment	RQ					5,585					219,025		219,025
27	Ashtabula Wind III LLC	RQ					218,878					6,834,311		6,834,311
28	Ashtabula Wind III LLC - Curtailment	RQ					17,040					533,108		533,108
29	MN Co Generation	OS					610					56,304		56,304
30	ND Co Generation	OS					95					2,018		2,018
31	SD Co Generation	OS					28					601		601
32	Midwest ISO Energy Market	OS					2,386,979					83,739,032		83,739,032
33	Southwest Power Pool ISO Energy Market	OS					5,437					(3,204,862)		(3,204,862)
15	TOTAL						3,241,351	0	0	0	2,056,956	98,155,182	68,916	100,281,054

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: OtherChargesOfPurchasedPower

Nomination charge

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")**

- Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
- In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
- In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
- Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
- Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
- Report in column (i) and (j) the total megawatt-hours received and delivered.
- In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
- The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
- Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)
1	Badger, SD	Western Area Power Administration	Badger, SD	LFP	4	(1)	Badger, SD		1,488	1,488	9,510			9,510
2	Newfolds, MN	Western Area Power Administration	Newfolds, MN	LFP	4	(1)	Newfolds, MN		2,843	2,843	25,420			25,420
3	Nielsen, MN	Western Area Power Administration	Nielsen, MN	LFP	4	(1)	Nielsen, MN		655	655	7,715			7,715
4	Shelly, MN	Western Area Power Administration	Shelly, MN	LFP	4	(1)	Shelly, MN		1,627	1,627	16,437			16,437
5	Fort Totten Indian Agency	Western Area Power Administration	Fort Totten, ND	LFP	4	(1)	Fort Totten, ND		300	300	1,768			1,768
6	State Development Center	Western Area Power Administration	Grafton, ND	LFP	4	(1)	Grafton, ND		4,347	4,347	21,329			21,329
7	North Dakota School for Deaf	Western Area Power Administration	Devils Lake, ND	LFP	4	(1)	Devils Lake, ND		448	448	5,427			5,427
8	North Dakota School of Forestry	Western Area Power Administration	Bottineau, ND	LFP	4	(1)	Bottineau, ND		1,116	1,116	11,209			11,209
9	North Dakota College of Science	Western Area Power Administration	Wahpeton, ND	LFP	4	(1)	Wahpeton, ND		7,949	7,949	92,492			92,492
10	Turtle Mountain Indian Agency	Western Area Power Administration	Belcourt, ND	LFP	4	(1)	Belcourt, ND		2,253	2,253	28,356			28,356
11	Oakes O&M Headquarters	Western Area Power Administration	Oakes, ND	LFP	4	(1)	Oakes, ND		71	71	1,343			1,343
12	Minnkota Power Cooperative, Inc.	Minnkota Power Cooperative, Inc.	Various Interconnects	OS	<sup>(g)</sup> See Footnote	(1)	Various Interconnects		226,026	211,239		211,239	920,934	1,132,173
13		U.S. Bureau of Reclamation	Otter Tail Power Company	OS	—	—	(1)		1,173					
14		Various Companies	Otter Tail Power Company	OS	—	—	(1)		(277,657)					
15		<sup>(g)</sup> Various Companies	Otter Tail Power Company	OS	—	—	(1)		(1,173)					
16		<sup>(g)</sup> Various Companies	Various Companies	OS			Various Interconnects						5,075,261	5,075,261
17	Midwest Independent System Operator	Various Companies	Various Companies	OS	OATT	System	System		0				45,079,272 <sup>(g)</sup>	45,079,272
18	<sup>(g)</sup> See Footnote					<sup>(g)</sup> See Footnote			0					
35	TOTAL							0	(28,534)	234,336	221,006	211,239	51,075,467	51,507,712

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Lines 1-10 Otter Tail Power Company wheels WAPA's portion of customers' load.  
 Line 11 Otter Tail Power Company wheels WAPA's total load to customer.  
 Line 12 Otter Tail Power Company wheels MPC's total load to various interconnects  
 Lines 13 - 15 contain losses and regulation that result from interconnects with various companies in the integrated system.

(b) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Various companies. Miscellaneous losses - mwh received.

(c) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Generator Interconnection Agreements and/or Facility Service Agreements between various parties

(d) Concept: RateScheduleTariffNumber

Original Service Agreement No. 30 under Otter Tail Power Company FERC Electric Tariff, Original Volume No. 1

(e) Concept: TransmissionPointOfReceipt

(1) Various points of interconnect in the intergrated system

(f) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Midwest Independent System Operator Transmission

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**TRANSMISSION OF ELECTRICITY BY ISO/RTOs**

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1	Not Applicable				
40	TOTAL				

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)**

- Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
- In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
- In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:  
FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
- Enter ""TOTAL"" in column (a) as the last line.
- Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Otter Tail Power Company	FNS					22,960,081	22,960,081
2	Montana-Dakota Utilities Co.	OS				775,032		775,032
3	Central Power Electric Cooperative, Inc	FNS				26,919		26,919
4	PKM Electric Coop Inc.	FNS				2,255		2,255
	TOTAL		0	0	0	804,206	22,960,081	23,764,287

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

The expenses incurred are for transmission of electricity and supporting services provided by the Midcontinent Independent System Operator and the Southwest Power Pool.

FERC FORM NO. 1 (REV. 02-04)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)**

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	349,212
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	23,981
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	261,891
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Miscellaneous labor	152,554
7	Public Relations Expenses:	
8	Labor	10,357
9	Greater North Dakota Chamber of Commerce	5,000
10	Minnesota Safety Council Inc	5,000
11	Items less than \$5,000 each	16,991
12	Director Fees and Expense:	
13	Director Fees	465,672
46	<u>TOTAL</u>	1,290,658

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**

- Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
- Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year. Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used. In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used. For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

**A. Summary of Depreciation and Amortization Charges**

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,561,857		3,561,857
2	Steam Production Plant	14,582,393	86,825			14,669,218
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	97,354				97,354
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	21,062,580	435,074			21,497,654
7	Transmission Plant	11,835,967				11,835,967
8	Distribution Plant	13,814,230				13,814,230
9	Regional Transmission and Market Operation					
10	General Plant	3,257,587				3,257,587
11	Common Plant-Electric					
12	TOTAL	64,650,111	521,899	3,561,857		68,733,867

**B. Basis for Amortization Charges**

The \$3,561,857 Amortization of limited term Electric Plant is: Franchise Consents (302):\$41,634 for hydro plant license with a remaining life of 40 years at a rate of 2.50% Miscellaneous Intangible Plant (303):\$951,067 for computer software with a 5-year service life at a rate of 20.0% \$2,569,615 for computer software with a 10-year service life at a rate of 10.0%

**C. Factors Used in Estimating Depreciation Charges**

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production -						
13	Big Stone Plant -						
14	311	48,355	34 years, 6 months, 11 days	(5.8)%	2.79%	SQ	23 years, 7 months, 28 days
15	312	152,841	32 years, 11 months, 1 day	(5.8)%	3.46%	SQ	23 years, 8 months, 1 day
16	314	10,998	42 years, 3 months	(5.8)%	1.74%	SQ	23 years, 7 months, 21 days
17	315	11,363	36 years, 9 months, 22 days	(5.8)%	2.52%	SQ	23 years, 7 months, 28 days
18	316	1,930	38 years, 7 days	(5.8)%	2.64%	SQ	23 years, 7 months, 24 days
19	Hoot Lake Plant -						
20	312 - Units 2, 3	6,609	35 years, 11 months, 9 days		2.24%	SQ	28 years, 3 months, 26 days
21	Coyote Plant -						
22	311	7,999	49 years, 5 months, 27 days	(8.7)%	1.67%	SQ	18 years, 11 months, 5 days
23	312	39,227	39 years, 10 months, 24 days	(8.7)%	2.4%	SQ	18 years, 11 months, 9 days
24	314	9,575	37 years, 5 months, 12 days	(8.7)%	2.57%	SQ	18 years, 11 months, 12 days
25	315	3,092	46 years, 7 months, 21 days	(8.7)%	1.81%	SQ	18 years, 11 months, 5 days
26	316	1,344	32 years, 2 months, 12 days	(8.7)%	3.43%	SQ	18 years, 11 months, 12 days
27	STEAM PROD	282,098					
28	Hydro Production -						
29	Hoot Lake Hydro -						
30	331 - Units 2, 3		97 years, 3 months, 4 days		0.01%	SQ	37 years, 15 days
31	332 - Units 2, 3	5	80 years, 4 months, 10 days		0.04%	SQ	37 years, 1 month, 28 days
32	333 - Units 2, 3	1	71 years, 10 months, 28 days		0.03%	SQ	37 years, 2 months, 27 days
33	334 - Units 2, 3	456	66 years, 10 months, 10 days		2.5%	SQ	37 years, 3 months, 7 days
34	335 - Units 2, 3	4	46 years, 1 month, 2 days		0.24%	SQ	37 years, 4 months, 28 days
35	Wright Hydro -						

36	331		72 years, 4 days		0.06%	SQ	37 years, 2 months, 23 days
37	332	71	50 years, 8 months, 19 days		0.21%	SQ	37 years, 4 months, 13 days
38	333	16	48 years, 15 days		0.08%	SQ	37 years, 4 months, 21 days
39	334	9	54 years, 3 months, 26 days		0.11%	SQ	37 years, 4 months, 6 days
40	335	7	52 years, 2 months, 16 days		0.17%	SQ	37 years, 4 months, 13 days
41	Pisgah Hydro -						
42	331		77 years, 9 months, 22 days		0.05%	SQ	37 years, 2 months, 9 days
43	332	2,620	40 years, 4 months, 10 days		2.3%	SQ	37 years, 5 months, 9 days
44	333	8	53 years, 3 months		0.14%	SQ	37 years, 4 months, 10 days
45	334	5	53 years, 2 months, 12 days		0.13%	SQ	37 years, 4 months, 10 days
46	335	6	46 years, 1 month, 2 days		0.25%	SQ	37 years, 4 months, 28 days
47	Dayton Hollow Hydro -						
48	331	1	47 years, 26 days		0.22%	SQ	37 years, 4 months, 24 days
49	332	828	46 years, 9 months, 22 days		1.09%	SQ	37 years, 4 months, 24 days
50	333	12	52 years, 2 months, 1 day		0.14%	SQ	37 years, 4 months, 10 days
51	334	7	58 years, 8 months, 27 days		0.1%	SQ	37 years, 3 months, 29 days
52	335	9	46 years, 1 month, 24 days		0.23%	SQ	37 years, 4 months, 28 days
53	Taplin Gorge Hydro -						
54	331		74 years, 11 months, 23 days		0.02%	SQ	36 years, 11 months, 12 days
55	332	30	16 years, 4 months, 24 days		0.12%	SQ	37 years, 3 months, 18 days
56	333		82 years, 8 months, 9 days		0.02%	SQ	36 years, 11 months, 1 day
57	334	2	22 years, 3 months, 29 days		0.08%	SQ	37 years, 3 months, 18 days
58	335	7	11 years, 7 months, 6 days		0.17%	SQ	37 years, 4 months, 17 days
59	Bemidji Hydro -						
60	331	13	13 years, 3 months, 11 days		0.16%	SQ	0 days
61	332	72	13 years, 1 month, 2 days		0.22%	SQ	0 days
62	333	15	19 years, 9 months, 11 days		0.11%	SQ	0 days
63	334		73 years, 2 months, 19 days		0.12%	SQ	0 days
64	335		11 years, 11 months, 16 days		0.19%	SQ	0 days
65	HYDRO PROD	4,102					
66	Other Production -						
67	Jamestown Peaking #1 -						
68	341	48	35 years, 9 months, 15 days	(5.9)%	2.01%	SQ	11 years, 3 months, 15 days
69	342	109	28 years, 3 months, 4 days	(5.9)%	3.06%	SQ	11 years, 3 months, 18 days
70	343	502	37 years, 11 months, 23 days	(5.9)%	1.99%	SQ	11 years, 3 months, 15 days
71	345	22	56 years, 1 month, 21 days	(5.8)%	1.79%	SQ	11 years, 3 months, 11 days
72	346	31	22 years, 4 months, 13 days	(5.9)%	3.72%	SQ	11 years, 3 months, 18 days
73	Lake Preston Peaking -						
74	341	27	42 years, 1 month, 24 days	(6.9)%	1.63%	SQ	11 years, 3 months, 15 days
75	342	43	39 years, 10 months, 24 days	(6.9)%	1.76%	SQ	11 years, 3 months, 15 days
76	343	359	43 years, 2 months, 5 days	(6.9)%	1.58%	SQ	11 years, 3 months, 15 days
77	345	47	42 years, 1 month, 28 days	(6.9)%	1.65%	SQ	11 years, 3 months, 15 days
78	346	1	48 years, 7 months, 21 days	(6.9)%	0.99%	SQ	11 years, 3 months, 11 days
79	Jamestown Peaking #2 -						
80	341	7	27 years, 7 months, 21 days	(5.9)%	3.1%	SQ	11 years, 3 months, 18 days
81	342	4	31 years, 6 months, 22 days	(5.8)%	1.38%	SQ	11 years, 3 months, 11 days
82	343	439	43 years, 3 months, 11 days	(5.8)%	1.51%	SQ	11 years, 3 months, 15 days
83	345	31	21 years, 3 months, 18 days	(5.9)%	4.34%	SQ	11 years, 3 months, 18 days
84	346		45 years, 9 months, 11 days	(5.9)%	(0.19)%	SQ	11 years, 3 months, 15 days
85	Fergus Falls Control Center -						
86	343	147	34 years, 3 months, 11 days	(5)%	3.55%	SQ	8 years, 4 months, 17 days
87	Solway Combustion Turbine -						
88	341	2,442	31 years, 3 months, 29 days	(1.6)%	3.25%	SQ	16 years, 1 month, 6 days

89	342	559	32 years, 5 months, 23 days	(1.6)%	3.35%	SQ	16 years, 1 month, 6 days
90	343	12,754	30 years, 3 months, 26 days	(1.6)%	3.93%	SQ	16 years, 1 month, 6 days
91	345	655	32 years, 4 months, 6 days	(1.6)%	3.21%	SQ	16 years, 1 month, 6 days
92	346	173	29 years, 9 months	(1.6)%	3.48%	SQ	16 years, 1 month, 6 days
93	Astoria Station -						
94	341	23,004	35 years	(1.6)%	2.92%	SQ	34 years
95	342	5,413	35 years	(1.6)%	2.92%	SQ	34 years
96	343	98,781	35 years	(1.6)%	2.92%	SQ	34 years
97	345	6,766	35 years	(1.6)%	2.92%	SQ	34 years
98	346	1,353	35 years	(1.6)%	2.92%	SQ	34 years
99	Langdon Wind Energy Center -						
100	341	1,121	33 years, 8 months, 12 days	(4.9)%	2.51%	SQ	19 years, 10 months, 24 days
101	344	33,719	33 years, 29 days	(4.9)%	2.66%	SQ	19 years, 10 months, 24 days
102	345	3,409	33 years, 3 months	(4.9)%	2.56%	SQ	19 years, 10 months, 24 days
103	346	143	23 years, 1 month, 2 days	(4.9)%	4.93%	SQ	19 years, 11 months, 1 day
104	Ashtabula Wind Energy Center -						
105	341	1,590	33 years, 7 months, 28 days	(4.3)%	2.55%	SQ	20 years, 10 months, 6 days
106	344	54,649	33 years, 3 months, 22 days	(4.3)%	2.64%	SQ	20 years, 10 months, 6 days
107	345	3,222	33 years, 4 months, 6 days	(4.3)%	2.59%	SQ	20 years, 10 months, 6 days
108	346	124	22 years, 10 months, 28 days	(4.2)%	5.06%	SQ	20 years, 10 months, 13 days
109	Luverne Wind Energy Center -						
110	341	1,173	33 years, 7 months, 17 days	(7.1)%	2.7%	SQ	21 years, 9 months, 15 days
111	344	38,321	33 years, 1 month, 17 days	(7.1)%	2.89%	SQ	21 years, 9 months, 15 days
112	345	2,519	33 years, 7 months, 17 days	(7.1)%	2.7%	SQ	21 years, 9 months, 15 days
113	346	164	25 years, 1 month, 10 days	(7.1)%	4.58%	SQ	21 years, 9 months, 22 days
114	Merricourt Wind Energy Center -						
115	341	7,573	33 years, 5 months, 19 days	(5)%	3.18%	SQ	32 years, 4 days
116	344	227,202	33 years, 5 months, 19 days	(5)%	3.18%	SQ	32 years, 4 days
117	345	17,671	33 years, 5 months, 19 days	(5)%	3.18%	SQ	32 years, 4 days
118	346		33 years, 5 months, 19 days	(5)%	3.28%	SQ	32 years, 4 days
119	Minnesota Dakota Small Solar -						
120	343	149	24 years, 2 months, 19 days	(1)%	4.25%	SQ	22 years, 9 months
121	North Dakota Small Solar -						
122	343	151	24 years, 2 months, 19 days	(1)%	4.33%	SQ	21 years, 9 months, 22 days
123	OTHER PROD	546,617					
124	Transmission Plant -						
125	350.1	18,116	70 years		1.43%		
126	353	137,986	65 years, 1 month, 10 days	(5)%	1.54%	R1	56 years, 4 months, 10 days
127	354	174,640	75 years	(10)%	1.45%	R5	70 years, 1 month, 17 days
128	355	103,670	75 years, 3 months, 4 days	(50)%	1.89%	R2	60 years, 1 month, 2 days
129	356	129,086	75 years, 1 month, 6 days	(30)%	1.63%	R2	62 years, 11 months, 12 days
130	358	24	51 years, 26 days	(5)%	2.21%	S4	13 years, 1 month, 10 days
131	SUBTOTAL	563,522					
132	Distribution Plant -						
133	362	67,457	43 years, 6 months	5%	1.94%	SC	34 years, 5 months, 23 days
134	364	32,472	70 years, 1 month, 2 days	(100)%	2.9%	R3	48 years, 2 months, 5 days
135	365	13,902	65 years, 2 months, 23 days	(75)%	2.29%	R2.5	43 years, 1 month, 13 days
136	367	57,699	44 years, 10 months, 28 days	(5)%	2.14%	R4	29 years, 29 days
137	368	99,409	43 years, 4 days	30%	1.73%	R2.5	30 years, 5 months, 12 days
138	369	(4,160)	55 years, 4 months, 17 days	(200)%	5.78%	S5	29 years, 4 months, 24 days
139	369.1	25,613	50 years, 1 month, 21 days	(20)%	2.23%	R4	32 years, 10 months, 21 days
140	370	17,649	29 years, 2 months, 12 days		3.28%	L1	19 years, 4 months, 13 days
141	370.05	790	20 years		4.88%	S3	17 years, 6 months, 26 days

142	370.1	114	16 years, 1 month, 21 days		0.73%	R5	1 year, 9 months
143	370.2		5 years		20%	SQ - Amortized	0 days
144	371.1	21	0 days		10%	SQ - Amortized	10 years
145	371.2	8,202	25 years, 5 months, 19 days		3.92%	O3	24 years, 6 months
146	373	8,635	22 years, 3 months, 22 days	(5)%	4.84%	L0.5	18 years, 1 month, 13 days
147	SUBTOTAL	327,803					
148	General Plant -						
149	390	13,784	50 years, 11 months, 27 days	5%	2%	R1	32 years, 10 months, 2 days
150	390.1	4,085	38 years, 2 months, 27 days	45%	0.91%	SQ	18 years
151	390.2	297	29 years, 6 months, 7 days	31.2%	0.41%	SQ	22 years, 8 months, 27 days
152	390.25	2,083	60 years	50%	0.82%	SQ	57 years
153	390.3	2,723	54 years, 10 months, 13 days	75.8%	(0.53)%	SQ	22 years, 8 months, 5 days
154	391	285	15 years		6.67%	SQ - Amortized	4 years, 10 months, 21 days
155	391.1	207	10 years		10%	SQ - Amortized	3 years, 2 months, 16 days
156	391.2	90	10 years		10%	SQ - Amortized	4 years, 5 months, 9 days
157	391.5	1,940	5 years		20%	SQ - Amortized	1 year, 9 months
158	391.6	1,611	5 years		20%	SQ - Amortized	2 years, 4 months, 21 days
159	392	20,022					
160	Aircraft	1,862	10 years	25%			
161	Autos		5 years	15%			
162	Light Trucks		10 years	10%			
163	Heavy Trucks & Semi		10 years	15%			
164	Tractors (Includes		10 years	15%			
165	Cranes)						
166	Trailers		15 years	10%			
167	Portable Oil Purifier		10 years	20%			
168	Trenchers		10 years	10%			
169	Misc. Light Equip.		10 years	10%			
170	Misc. Heavy Equip.		15 years	15%			
171	394	2,180	15 years		6.67%	SQ - Amortized	6 years, 8 months, 9 days
172	394.2	338	15 years		6.67%	SQ - Amortized	5 years, 7 months, 24 days
173	395		15 years		6.67%	SQ - Amortized	0 days
174	396	1,254	23 years, 5 months, 12 days	5%	3.91%	L0	19 years, 10 months, 6 days
175	397	2,750	15 years		6.67%	SQ - Amortized	9 years, 9 months, 11 days
176	397.1	7	10 years		10%	SQ - Amortized	1 year
177	397.2	1,794	15 years		6.67%	SQ - Amortized	7 years, 1 month, 10 days
178	397.3	79	10 years		10%	SQ - Amortized	2 years, 2 months, 16 days
179	397.4	847	50 years, 5 months, 9 days	(5)%	1.64%	R2.5	30 years, 6 months, 7 days
180	SUBTOTAL	58,238					
181	TOTAL	1,782,380					
182	(a) SUBACCOUNTS USED						

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FOOTNOTE DATA

(a) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

SUBACCOUNTS USED

312.1	Ash Landfills
350.1	Easements
369.1	Underground Services
370.1	Load Management Switches
370.2	Interruption Monitors
371.2	All Other Private Lighting
390.1	General Office Building
390.2	Fleet Service Center Building - Fergus Falls
390.3	Fleet Service Center Building - Jamestown
390.3	Central Stores Building
391.1	Office Equipment
391.2	Duplicating Equipment
391.5	Computer Systems
391.6	Computer Related Equipment
394.2	AMR Equipment
397.1	Radio Telecommunication Equipment
397.2	Microwave Equipment
397.3	Radio Load Control Equipment
397.4	Communication Towers

Column (b) is the balance of plant in service (except land) at the beginning of the year, less the associated reserve for accumulated depreciation and includes amounts tentatively classified in Account 106, Completed Construction Not Classified.

Column (e) rates are applied to the original cost per books (Accounts 101 and 106) from the close of the prior month except when major additions and retirements occur which significantly affect depreciation expense.

Column (d) factors are a composite of rates allowed in the jurisdictions served.

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**REGULATORY COMMISSION EXPENSES**

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	MN Dept. of Commerce/Public Utilities Commission	356,419		356,419		Electric	928	356,419				
2	Administrative Cost Assessment Fees					Electric	928					
3	E017/GR-15-1033 (MN Rate Case; BSAT/MVP Appeal)	385,030	30,275	415,305	1,508,373	Electric	928	415,305			377,093 <sup>(a)</sup>	1,131,280
4	MN FCA Forecast		67,721	67,721		Electric	928	67,721				
5	E017-M-21-830 (MN Renewable Resource Cost Recovery)		19,944	19,944		Electric	928	19,944				
6	E017-M-21-382 (MN Electric Utility Infrastructure Costs)		17,893	17,893		Electric	928	17,893				
7	E017-M-21-99 (Energy Intensive Trade Exposed Customer Rate)		15,337	15,337		Electric	928	15,337				
8	E017-RP-21-339 - Integrated Resource Plan 2022-2036		74,840	74,840		Electric	929	74,840				
9	E017/M-22-159 (SRSQ Reports)		17,892	17,892		Electric	928	17,892				
10	Miscellaneous - MN		254,004	254,004				254,007				
11	ND Public Service Commission	341,402		341,402				341,402				
12	Administrative Cost Assessment Fees					Electric	928					
13	PU-17-398 (ND Rate Case)				121,937	Electric	928				121,937 <sup>(a)</sup>	
14	PU-21-364, PU-21-365, PU-21-366 (ND Applied Blockchain)		65,969	65,969		Electric	928	65,969				
15	PU-22-312 (Adv Grid Infrastructure)		28,721	28,721		Electric	928	28,721				
16	Miscellaneous - ND		80,865	80,865				80,865				
17	SD Public Service Commission	73,958		73,958				73,958				
18	Administrative Cost Assessment Fees					Electric	928					
19	EL 18-021 (SD Rate Case)				108,054	Electric	928				108,054 <sup>(a)</sup>	
20	Miscellaneous - SD		108,845	108,845		Electric	928	108,845				
21	Federal Energy Regulatory Commission:											
22	MISO Schedule 10		511,746	511,746		Electric	928	511,746				
23	SPP Schedule 12		22,641	22,641		Electric	928	22,641				
24	North American Electric Reliability Corporation	268,427		268,427		Electric	928	268,427				
25	Reactive Power Filing Docket ER21-1622		25,844	25,844		Electric	928	25,844				
26	FERC/RTO Policy	2,227	54,155	56,382				56,382				
46	TOTAL	1,427,463	1,396,692	2,824,155	1,738,364			2,824,158			607,084	1,131,280

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FOOTNOTE DATA

(a) Concept: DeferredRegulatoryCommissionExpensesAmortized
Amortized period is Jan 2021 through Dec 2025
(b) Concept: DeferredRegulatoryCommissionExpensesAmortized
Amortized period is Jan 2018 through Dec 2022
(c) Concept: DeferredRegulatoryCommissionExpensesAmortized
Amortized period is Jan 2018 through Dec 2022

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES**

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).

2. Indicate in column (a) the applicable classification, as shown below:  
Classifications:

A. Electric R, D and D Performed Internally:

1. Generation

a. hydroelectric

- i. Recreation fish and wildlife
- ii. Other hydroelectric

- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Unconventional generation
- f. Siting and heat rejection

2. Transmission

- a. Overhead
  - b. Underground
3. Distribution
- 4. Regional Transmission and Market Operation
  - 5. Environment (other than equipment)
  - 6. Other (Classify and include items in excess of \$50,000.)
  - 7. Total Cost Incurred

B. Electric, R, D and D Performed Externally:

- 1. Research Support to the electrical Research Council or the Electric Power Research Institute
- 2. Research Support to Edison Electric Institute
- 3. Research Support to Nuclear Power Groups
- 4. Research Support to Others (Classify)
- 5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""

7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	Electric Utility R&D						
2	PERFORMED INTERNALLY:						
3	Other	Miscellaneous	110		506.0	110	
4	Other	Miscellaneous	39		566.0	39	
5	Other	Miscellaneous	1,575		920.0	1,575	
6	Other	Miscellaneous	4,032		930.2	4,032	
7	PERFORMED EXTERNALLY:						
8		E Source Companies LLC		19,949	930.2	19,949	
9	TOTAL:		5,756	19,949		25,705	

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**DISTRIBUTION OF SALARIES AND WAGES**

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	7,609,371		
4	Transmission	4,687,446		
5	Regional Market	754,671		
6	Distribution	5,507,690		
7	Customer Accounts	7,426,095		
8	Customer Service and Informational	1,644,300		
9	Sales	252,901		
10	Administrative and General	30,876,050		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	58,758,524		
12	Maintenance			
13	Production	4,516,633		
14	Transmission	2,161,343		
15	Regional Market	44,527		
16	Distribution	6,205,232		
17	Administrative and General	2,063,781		
18	TOTAL Maintenance (Total of lines 13 thru 17)	14,991,516		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,126,004		
21	Transmission (Enter Total of lines 4 and 14)	6,848,789		
22	Regional Market (Enter Total of Lines 5 and 15)	799,198		
23	Distribution (Enter Total of lines 6 and 16)	11,712,922		
24	Customer Accounts (Transcribe from line 7)	7,426,095		
25	Customer Service and Informational (Transcribe from line 8)	1,644,300		
26	Sales (Transcribe from line 9)	252,901		
27	Administrative and General (Enter Total of lines 10 and 17)	32,939,831		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	73,750,040		73,750,040
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	73,750,040		73,750,040
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	22,852,950		22,852,950
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	22,852,950		22,852,950
72	Plant Removal (By Utility Departments)			
73	Electric Plant	224,919		224,919
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	224,919		224,919
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Fuel Stock (151)			
80	Miscellaneous Deferred Debits (186)	1,191,403		1,191,403
81	Other Electric Revenue (456)	50,309		50,309
82	Expenses of Nonutility Operations (417.1)	145,762		145,762
83	Exp. for Certain Civic, Political and Related Activity (426.4)	313,203		313,203
84	Other Deductions (426.5)	251,472		251,472
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,952,149		1,952,149
96	TOTAL SALARIES AND WAGES	98,780,058		98,780,058

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: SalariesAndWagesOtherAccountsDescription

Salaries and wages are included in the specified accounts because they are either not provided for elsewhere, are nonutility in nature, or are nonoperating.

FERC FORM NO. 1 (ED. 12-88)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
<b>COMMON UTILITY PLANT AND EXPENSES</b>			
<ol style="list-style-type: none"> <li>1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.</li> <li>2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.</li> <li>3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.</li> <li>4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.</li> </ol>			
Not Applicable			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS**

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	MISO				
8	Energy				
9	Net Purchases (Account 555)	42,760,957	77,333,170	101,077,418	149,185,076
10	Net Sales (Account 447)	(2,170,166)	(4,862,123)	(11,353,340)	(13,698,595)
11	Transmission Rights (555)	(25,182,570)	(40,159,982)	(46,722,145)	(61,152,580)
12	Transmission Rights (447)				
13	Ancillary Services (555)	(113,624)	(385,579)	(511,848)	(412,667)
14	Ancillary Services (447)				
15	Other Items (list separately) (555)	411,727	804,359	(1,339,709)	(3,765,314)
16	Other Items (list separately) (447)	(222,017)	(1,030,320)	(1,692,487)	(4,629,321)
17	SPP				
18	Net Purchases (Account 555)	(317,544)	(1,470,008)	(2,186,951)	(3,048,199)
19	Net Sales (Account 447)				
20	Transmission Rights (555)		(194,122)	(194,123)	(194,122)
21	Ancillary Services (555)	(37)	383	3,211	3,513
22	Other Items (list separately) (555)	(473)	1,690	31,788	33,947
46	TOTAL	15,166,253	30,037,468	37,111,814	62,321,738

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**PURCHASES AND SALES OF ANCILLARY SERVICES**

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff. In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			138,547	2,449,847	\$/MW-Hr	403,000
2	Reactive Supply and Voltage				10,394,128	\$/MW-Hr	1,559,119
3	Regulation and Frequency Response				0	\$/MW-Hr	
4	Energy Imbalance				0	0	
5	Operating Reserve - Spinning				0	0	
6	Operating Reserve - Supplement				0	0	
7	Other				0	\$/MW-Hr	
8	Total (Lines 1 thru 7)			138,547	12,843,975		1,962,119

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**MONTHLY TRANSMISSION SYSTEM PEAK LOAD**

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	944	7	9	943	1				
2	February	940	24	9	939	1				
3	March	877	11	8	876	1				
4	Total for Quarter 1				2,758	3				
5	April	772	19	9	771	1				
6	May	709	2	12	708	1				
7	June	808	23	16	807	1				
8	Total for Quarter 2				2,286	3				
9	July	809	18	15	808	1				
10	August	783	5	17	782	1				
11	September	812	7	18	811	1				
12	Total for Quarter 3				2,401	3				
13	October	795	26	9	794	1				
14	November	881	30	8	880	1				
15	December	988	22	18	987	1				
16	Total for Quarter 4				2,661	3				
17	Total				10,106	12				
	NAME OF SYSTEM: Not Applicable									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total									

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

The peak numbers for October through December are estimated and are from MISO's 5-55 or 5-14 settlement data.

**FERC FORM NO. 1 (NEW. 07-04)**

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**Monthly ISO/RTO Transmission System Peak Load**

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Not Applicable									
1	January	0								
2	February	0								
3	March	0								
4	Total for Quarter 1									
5	April	0								
6	May	0								
7	June	0								
8	Total for Quarter 2									
9	July	0								
10	August	0								
11	September	0								
12	Total for Quarter 3									
13	October	0								
14	November	0								
15	December	0								
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2022-12-31	Year/Period of Report End of: 2022/ Q4
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**ELECTRIC ENERGY ACCOUNT**

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	5,592,368
3	Steam	1,819,294	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,378
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	274,452
5	Hydro-Conventional	12,850	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	10,199
7	Other	1,296,171	27	Total Energy Losses	226,399
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	3,128,315	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	6,106,796
10	Purchases (other than for Energy Storage)	3,241,351			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	(28,534)			
17	Delivered	234,336			
18	Net Transmission for Other (Line 16 minus line 17)	(262,870)			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	6,106,796			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2022-12-31	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: EnergyLosses

Includes all retail, wholesale, and transmission wheeling service system losses, losses on other systems due to sales for resale, and inadvertent energy imbalances.

(b) Concept: ElectricPowerWheelingEnergyReceived

Includes interchange transactions and losses thereon.

(c) Concept: ElectricPowerWheelingEnergyDelivered

Includes interchange transactions and losses thereon.

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**MONTHLY PEAKS AND OUTPUT**

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non-integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	608,659	22,799	944	7	9
30	February	557,679	22,190	940	24	9
31	March	510,027	20,828	877	11	8
32	April	416,143	15,792	772	19	9
33	May	438,928	17,042	709	2	12
34	June	475,711	24,135	808	23	16
35	July	455,787	31,088	809	18	15
36	August	472,972	41,977	783	5	17
37	September	415,937	31,567	812	7	18
38	October	481,129	15,292	795	26	9
39	November	476,594	17,198	881	30	8
40	December	797,230	14,544	988	22	18
41	Total	6,106,796	274,452			

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**Steam Electric Generating Plant Statistics**

- Report data for plant in Service only.
- Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
- Indicate by a footnote any plant leased or operated as a joint facility.
- If net peak demand for 60 minutes is not available, give data which is available, specifying period.
- If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
- If gas is used and purchased on a term basis report the BTU content or the gas and the quantity of fuel burned converted to Mct.
- Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
- If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
- Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
- For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
- For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
- If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0	Plant Name: Astoria	Plant Name: 18 Big Stone	Plant Name: 28 Coyote	Plant Name: Jamestown	Plant Name: Lake Preston	Plant Name: Solway		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		Gas Turbine	Steam	Steam	Gas Turbine	Gas Turbine	Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Conventional	Conventional	Conventional	Conventional	Conventional	Conventional		
3	Year Originally Constructed		2021	1975	1981	1976	1978	2003		
4	Year Last Unit was Installed		2021	1975	1981	1978	1978	2003		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		245	223	145	48	24	45.00		
6	Net Peak Demand on Plant - MW (60 minutes)		284	256	150	40	19	43		
7	Plant Hours Connected to Load		873	6,427	6,643	134	31	2,515		
8	Net Continuous Plant Capability (Megawatts)		242	258	148	40	19	42		
9	When Not Limited by Condenser Water		242	258	148	40	19	42		
10	When Limited by Condenser Water		242	258	148	40	19	42		
11	Average Number of Employees		2	76	75	1	1	2		
12	Net Generation, Exclusive of Plant Use - kWh		175,855,090	1,023,430,328	795,864,029	890,595	159,295	84,981,836		
13	Cost of Plant: Land and Land Rights			380,568	713,587	24,614	12,339	89,809		
14	Structures and Improvements		25,091,933	80,820,308	34,941,558	311,512	293,405	4,816,246		
15	Equipment Costs		122,507,674	256,813,757	145,876,038	7,684,747	4,033,048	23,615,856		
16	Asset Retirement Costs		1,524,014	396,580	1,930,034		0			
17	Total cost (total 13 thru 20)		149,123,621	338,411,213	183,461,217	8,020,873	4,338,792	28,521,911		
18	Cost per KW of Installed Capacity (line 17/5) Including		609	1,518	1,265	167	181	634		
19	Production Expenses: Oper, Supv, & Engr		234	617,873	738,571	4,680	17,912	349		
20	Fuel		14,740,380	22,698,371	21,689,537	399,046	80,309	5,358,738		
21	Coolants and Water (Nuclear Plants Only)						0			
22	Steam Expenses			2,739,009	2,214,635		0			
23	Steam From Other Sources						0			
24	Steam Transferred (Cr)						0			
25	Electric Expenses		172,633	1,001,142	765,575	15,331	4,945	148,503		
26	Misc Steam (or Nuclear) Power Expenses		114,325	2,423,832	813,517	65,102	343	313,512		
27	Rents				(5,533)		0	129		
28	Allowances						0			
29	Maintenance Supervision and Engineering		9,837	359,447	263,502	2,490	1,691	8,063		
30	Maintenance of Structures		29,949	420,348	313,983	5,843	3,338	38,360		
31	Maintenance of Boiler (or reactor) Plant			2,743,341	3,913,704		0			
32	Maintenance of Electric Plant		634,200	1,098,929	1,766,588	113,679	74,120	261,315		
33	Maintenance of Misc Steam (or Nuclear) Plant		90,009	358,722	532,480		0	9,907		
34	Total Production Expenses	0	15,791,567	34,461,014	33,006,559	606,171	182,658	6,138,876		
35	Expenses per Net kWh	0.0000	0.0898	0.0337	0.0415	0.6806	1.1467	0.0722		
35	Plant Name	Astoria	Big Stone	Big Stone	Coyote	Coyote	Jamestown	Lake Preston	Solway	Solway
36	Fuel Kind	Natural Gas	Coal	Oil	Coal	Oil	Oil	Oil	Natural Gas	Oil

37	Fuel Unit	MMBTU	T	bbl	T	bbl	bbl	bbl	MMBTU	bbl
38	Quantity (Units) of Fuel Burned	1,853,645	680,660	2,169	652,027	3,772	3,879	923	890,442	495
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,865,700	8,231	140,000	7,121	140,000	140,000	140,000	885,165	140,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	7.930	34.048	143.350	32.794	157.500	196.182	0.000	6.000	180.730
41	Average Cost of Fuel per Unit Burned	7.910	33.085	107.860	32.691	119.280	114.742	86.900	5.990	94.122
42	Average Cost of Fuel Burned per Million BTU	7.910	2.010	18.344	2.295	20.286	19.514	14.779	5.990	16.007
43	Average Cost of Fuel Burned per kWh Net Gen	0.084	0.022	0.000	0.027	0.000	0.448	0.504	0.063	
44	Average BTU per kWh Net Generation	10,541.000	11,135.000	0.000	11,749.000	0.000	25,610.000	34,070.000	10,512.000	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: PlantName

Big Stone - Joint facility operated by Otter Tail Power Company

(b) Concept: PlantName

Coyote - Joint facility operated by Otter Tail Power Company

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**Hydroelectric Generating Plant Statistics**

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 0 Plant Name: Not Applicable
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0	0
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	<b>Net Plant Capability (in megawatts)</b>		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - kWh	0	0
13	<b>Cost of Plant</b>		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	Total cost (total 13 thru 20)	0.0000	0.0000
21	Cost per KW of Installed Capacity (line 20 / 5)		
22	<b>Production Expenses</b>		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net kWh	0	0

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**Pumped Storage Generating Plant Statistics**

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWh as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. Not Applicable Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)		
2	Year Originally Constructed		
3	Year Last Unit was Installed		
4	Total installed cap (Gen name plate Rating in MW)		
5	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
6	Plant Hours Connect to Load While Generating	0	0
7	Net Plant Capability (in megawatts)	0	0
8	Average Number of Employees		
9	Generation, Exclusive of Plant Use - kWh	0	0
10	Energy Used for Pumping		
11	Net Output for Load (line 9 - line 10) - Kwh	0	0
12	<b>Cost of Plant</b>		
13	Land and Land Rights		
14	Structures and Improvements	0	0
15	Reservoirs, Dams, and Waterways	0	0
16	Water Wheels, Turbines, and Generators	0	0
17	Accessory Electric Equipment	0	0
18	Miscellaneous Powerplant Equipment	0	0
19	Roads, Railroads, and Bridges	0	0
20	Asset Retirement Costs	0	0
21	Total cost (total 13 thru 20)		
22	Cost per KW of installed cap (line 21 / 4)		
23	<b>Production Expenses</b>		
24	Operation Supervision and Engineering	0	0
25	Water for Power	0	0
26	Pumped Storage Expenses	0	0
27	Electric Expenses	0	0
28	Misc Pumped Storage Power generation Expenses	0	0
29	Rents	0	0
30	Maintenance Supervision and Engineering	0	0
31	Maintenance of Structures	0	0
32	Maintenance of Reservoirs, Dams, and Waterways	0	0
33	Maintenance of Electric Plant	0	0
34	Maintenance of Misc Pumped Storage Plant	0	0
35	Production Exp Before Pumping Exp (24 thru 34)		
36	Pumping Expenses		
37	Total Production Exp (total 35 and 36)		
38	Expenses per kWh (line 37 / 9)		
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0	0

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**GENERATING PLANT STATISTICS (Small Plants)**

- Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
- Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
- List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
- If net peak demand for 60 minutes is not available, give the which is available, specifying period.
- If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	Hydro:												
2	Hoot Lake Hydro	1914	0.67	0.70	2,685	1,565,927	2,237,038	18,422		72,167			Hydro
3	Wright Hydro	1922	0.40	0.40	(5)	1,779,504	4,448,760	11,394		37,387			Hydro
4	Pisgah Hydro	1917	0.65	0.70	2,596	2,447,712	3,496,732	11,938		58,173			Hydro
5	Dayton Hollow Hydro	1909	0.97	1.00	5,673	3,169,445	3,169,445	10,719		62,357			Hydro
6	Taplin Gorge Hydro	1925	0.56	0.50	1,901	958,938	1,917,876	10,487		62,275			Hydro
7	Bemidji Hydro	1941	0.62	0.00	0	1,374,532		18,686		17,392			Hydro
8	Internal Combustion:												
9	<sup>(p)</sup> Fergus Falls Control Center	1995	0.00	0.00	0			1,903		7,963	Oil		Internal Combustion
10	Wind Turbine Plants:												
11	Langdon	2007	40.50	40.70	136,370	81,592,247	2,004,724	1,339,616		20,820			Wind
12	Ashtabula	2008	48.00	48.10	145,670	119,157,651	2,477,290	1,301,333		5,551			Wind
13	Luverne	2009	49.50	48.10	176,493	78,963,378	1,641,650	1,182,395		127,754			Wind
14	Merricourt	2020	150.00	147.60	575,653	267,096,679	1,809,598	1,384,389		3,774,012			Wind
15	Solar Plants:												
16	Blue Jay Solar	2020	0	0.03	54	168,580	5,619,344			250			Solar
17	Blue Heron Solar	2020	0	0.03	44	156,123	5,204,086			407			Solar

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FOOTNOTE DATA

(a) Concept: PlantName

The Fergus Falls Control Center Generator was retired in 2022. Prior to retirement, this unit had an original cost of \$591,638

(b) Concept: CostOfPlant

The Bemidji Hydro became inactive in June 2022.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**ENERGY STORAGE OPERATIONS (Large Plants)**

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requireme
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the pov costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and convers purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Pr C inc
1	Not Applicable			0												

Name of Respondent: Otter Tail Power Company	This report is:	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

**TRANSMISSION LINE STATISTICS**

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole mile of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
- Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
- Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
- Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
- Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expense
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1													7,544,958	2,144,267	37,445	9,726.67
2	Center	Maple River	345	345	Alum Tower	48.00	0	1	0		5,840,882	5,840,882				
3	Alexandria	MN Border	345	345	Steel Tower	0.00	0	1	-	2,908,447	30,054,193	32,962,640				
4	Big Stone South	Brookings	345	345	Steel Tower	72.00	0	1	-	3,602,817	51,612,464	55,215,281				
5	Big Stone South	Ellendale	345	345	Steel Tower	162.00	0	1	-	547,832	106,984,929	107,532,761				
6	Brookings	MN Border	345	345	Steel Tower	10.00	0	1	-	93,013	1,046,844	1,139,857				
7	Cedar Mountain	Helena	345	345	Steel Tower	73.00	0	2	-	1,365,905	6,388,228	7,754,133				
8	Cedar Mountain	Lyon County	345	345	Steel Tower	50.00	0	2	-	483,093	3,984,308	4,467,401				
9	Chub Lake	Hampton	345	345	Steel Tower	18.00	0	1	-	491,533	2,427,110	2,918,643				
10	Chub Lake	Helena	345	345	Steel Tower	21.00	0	1	-	869,812	2,154,448	3,024,260				
11	Hazel Creek	Lyon County	345	345	Steel Tower	25.00	0	1	-	156,242	2,011,398	2,167,640				
12	Lyon County	MN Border	345	345	Steel Tower	48.00	0	1	0	129,317	3,735,759	3,865,076				
13	MN Border	Bison	345	345	Steel Tower	35.00	0	1	-	616,125	8,167,232	8,783,357				
14	Monticello	Quarry Sub	345	345	Steel Tower	29.00	0	1	-	2,259,131	8,201,392	10,460,523				
15	St. Cloud	Alexandria	345	345	Steel Tower	78.00	0	1	-	2,680,036	23,297,499	25,977,535				
16								0	-							
17	Fergus Falls	Inman	230	230	Wood H	19.00	0	1	-		2,024,040	2,024,040				
18	Fergus Falls	Wahpeton	230	230	Wood H	29.00	0	1	-		2,231,308	2,231,308				
19	Wahpeton	Hankinson	230	230	Wood H	27.00	0	1	-		2,644,082	2,644,082				
20	Hankinson	Forman	230	230	Wood H	36.00	0	1	-	366,016	4,937,753	5,303,769				
21	Forman	Ellendale	230	230	Wood H	47.00	0	1	-		16,184,167	16,184,167				
22	Audubon (W 1/10)	Badoura	230	230	Wood H	6.00	0	1	-		414,677	414,677				
23	Audubon	Sheyenne	230	230	Wood H	42.00	0	1	-		1,693,664	1,693,664				
24	Winger (E 1/3)	Wilton	230	230	Alum Tower	18.00	0	1	-		1,852,883	1,852,883				
25	Grand Forks (M 1/3)	Winnepeg	230	230	Wood H	27.00	0	1	-		974,099	974,099				
26	Big Stone (N 1/3)	Hankinson	230	230	Wood H	23.00	0	1	-		803,584	803,584				
27	Big Stone (S 1/4)	Blair	230	230	Wood H	15.00	0	1	-		1,014,508	1,014,508				

28	Harvey	Coal Creek	230	230	Wood H	75.00	0	1	0		10,672,352	10,672,352				
29	Balta	Harvey	230	230	Wood H	22.00	0	1	-		4,433,901	4,433,901				
30	Rugby	Balta	230	230	Steel H	18.00	0	1	0		3,486,133	3,486,133				
31	Wilton	Cass Lake	230	230	Steel H	19.00	0	1	0	489,732	4,363,752	4,853,484				
32	Cass Lake	Boswell	230	230	Steel H	51.00	0	1	0	567,060	10,910,711	11,477,771				
33	Hazel Creek	MN Valley	230	345	Steel Tower	5.00	0	1	0	47,522	704,213	751,735				
34	Big Stone Plant	Big Stone South	230	230	Steel Tower	2.00	0	1	0	53,811	1,022,410	1,076,221				
35	Big Stone Plant	Big Stone South	230	230	Steel Tower	2.00	0	1	0	58,247	1,106,693	1,164,940				
36		Total	115	115	Wood H	481.00				118,776	15,255,379	15,374,155				
37		Total	115	115	SWP	439.00				2,672,111	38,086,363	40,758,474				
38		Total	115	115	Steel Tower	4.00				15,567	187,032	202,599				
39		Total	69	69		209.00				53,441	8,111,994	8,165,435				
40		Total	41.6	41.6	SWP	3,796.00					124,101,890	124,101,890				
41		Total	41.6	41.6	Underground	1.00					77,461	77,461				
36	TOTAL					6,082	0	35		20,645,586	513,201,735	533,847,321	7,544,958	2,144,267	37,445	9,726.67

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: OperatingExpensesOfTransmissionLine Column detail by line not available.
(b) Concept: MaintenanceExpensesOfTransmissionLine Column detail by line not available.
(c) Concept: RentExpensesOfTransmissionLine Column detail by line not available.
(d) Concept: OverallExpensesOfTransmissionLine Column detail by line not available.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**TRANSMISSION LINES ADDED DURING YEAR**

- Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
- Provide separate subheadings for overhead and under-ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and cost of Underground Conduit in column (m).
- If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construct
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Grant County Sub	New Norcross	7.00	Single Pole	18	1	1	1/0RT2	ACSR	Verticle Frame	115	421,060	1,706,821	2,560,231		4,688,112	Overgrour
2	Jamestown Downtown	Jamestown South West JCT	1.15	Wood Pole	25	1	1	1/0 T2	ACSR	3102	41.6	11,313	389,218	583,827		984,358	Overgrour
3	Jamestown Downtown	Jamestown South West JCT	0.46	Underground		1	1	500	KCMIL	Underground	41.6	9,467	325,690	488,535		823,692	Undergrou
44	TOTAL		9		43	3	3					441,840	2,421,729	3,632,593		6,496,162	

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(b) Concept: CostOfTransmissionLinesAdded
Estimated total cost.
(c) Concept: CostOfTransmissionLinesAdded
Estimated total cost.

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**SUBSTATIONS**

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
- Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVA)			Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVA) (c)	Secondary Voltage (In MVA) (d)	Tertiary Voltage (In MVA) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)
1	Astoria, SD - 345 kv - 620483	Transmission		345.00	115.00	43.00	112	1				
2	Bemidji, MN - 115 kv - 63246	Transmission		115.00	69.00	13.80	15	1				
3	Big Stone, SD - 230 kv - 620314	Transmission		230.00	115.00	13.80	569	2				
4	Big Stone, SD Highway 12 - 115 kv - 63215	Transmission		115.00	41.60	0.00	45	1				
5	Big Stone South, SD - 345 kv - 620417	Transmission		345.00	230.00	34.50	896	2				
6	Bottineau, ND - 115 kv - 63183	Transmission		115.00	41.60		40	2				
7	Browns Valley, MN - 230 kv (Peever) - 63325	Transmission		230.00	41.60		27	1				
8	Buffalo, ND - 345 kv - 63258	Transmission		345.00	115.00	43.00	224	2				
9	Canby, MN - 115 kv - 63211	Transmission		115.00	41.60		20	1				
10	Cass Lake, MN - 115 kv - 63347	Transmission		115.00	69.00	41.60	65	3				
11	Cass Lake, MN - 230 kv - 620447	Transmission		230.00	115.00	13.80	187	1				
12	Clearbrook, MN - 115 kv - 63241	Transmission		115.00	41.60		10	1				
13	Crookston, MN - 115 kv - 63249	Transmission		115.00	41.60		51	2				
14	Devils Lake, ND - East 115 kv - 63265	Transmission		115.00	41.60		34	1				
15	Devils Lake, ND - SW 115 kv - 224	Transmission		115.00	41.60		30	1				
16	Donaldson, MN - 115 kv - 63255	Transmission		115.00	41.60		20	2				
17	Fergus Falls, MN - Hoot Lake 115 kv - 63223	Transmission		115.00	43.80		60	1				
18	Fertile, MN - 115 kv - 63250	Transmission		115.00	41.60		10	1				
19	Finley, ND - Pickert 115 kv - 711	Transmission		230.00	72.00	41.60	60	1				
20	Forman, ND - Forman 230 kv - 63363	Transmission		230.00	115.00	41.60	125	1				
21	Hensel, ND - 115 kv - 63157	Transmission		115.00	72.00	43.80	33	1				
22	Hetland, SD - 115 kv - 63209	Transmission		115.00	41.60		45	1				
23	Jamestown, ND - 345 kv - 63369	Transmission		345.00	115.00	43.00	44	1				
24	Jamestown, ND - Peaking Plant 115 kv - 63272	Transmission		115.00	41.60		60	3				
25	Maple River, ND - 345 kv - 66792	Transmission		345.00	230.00	13.80	672	2				
26	Mapleton, ND - 115 kv - 63203	Transmission		115.00	41.60		15	1				
27	Marietta, MN - 115 kv - 63213	Transmission		115.00	41.60		10	1				
28	Merricourt, ND - 230 kv - 661992	Transmission		230.00	34.50	13.80	167	1				
29	New Effington, SD - 620328	Transmission		230.00	41.60		56	1				
30	Northwoods, MN - 115kv - 63282	Transmission		115.00	41.60		12	1				
31	Oakes, ND - 230 kv - 63362	Transmission		230.00	41.60		67	2				
32	Ortonville, MN - 115 kv - 63216	Transmission		115.00	41.60		44	1				
33	Pelican Rapids, MN - 115 k - 63234	Transmission		115.00	41.60		10	1				
34	Plummer, MN - 115kv - 7967	Transmission		115.00	41.60		18	1				
35	Rugby, ND - 230 kv - 620379	Transmission		230.00	115.00	41.60	140	1				
36	Rugby, ND - 230 kv - 620379	Transmission		230.00	115.00	13.80	75	1				
37	Spiritwood, ND - 620270	Transmission		115.00	41.60		31	2				
38	Toronto, SD - 115 kv - 63210	Transmission		115.00	41.60		45	1				
39	Wahpeton Inventory	Transmission		115.00	69.00	41.60			0			

40	Wahpeton Inventory	Transmission		115.00	43.80				1			
41	Wahpeton, ND - 230 kv - 620329	Transmission		230.00	115.00	43.00	280		2			
42	WAPA Summit, SD	Transmission		115.00	41.60		25	1				
43	Winger, MN 63238	Transmission		230.00	115.00	13.20	140	1				
44	Transmission Subs Under 10,000 kva											
45	Colgate	Transmission		69.00	43.80	12.50	6	1				
46	Green Valley	Transmission		67.00	41.60		7	1				
47	Lake Preston East River	Transmission		69.00	44.00		8	1				
48	St Vincent	Transmission		69.00	41.60		8	1				
49	Wahpeton Inventory	Transmission		69.00	41.60				1			
50	Bemidji, MN 25th Street	Distribution		69.00	12.50		15	1				
51	Bemidji, MN Airport	Distribution		41.60	12.50		10	1				
52	Bemidji, MN Nymore	Distribution		69.00	12.50		10	1				
53	Bemidji, MN Industrial Park	Distribution		69.00	12.50		8	1				
54	Bottineau, ND Downtown	Distribution		41.60	12.50		10	3				
55	Bottineau, ND South	Distribution		41.60	12.50		10	1				
56	Casselton, ND	Distribution		41.60	12.50		10	1				
57	Casselton, ND Ethanol plant	Distribution		115.00	12.50		66	2				
58	Cass Lake, MN	Distribution		115.00	12.50		10	1				
59	Clearbrook, MN Pipeline	Distribution		115.00	4.16		20	2				
60	Cooperstown, ND	Distribution		41.60	12.50		10	1				
61	Crookston, MN Parkview	Distribution		41.60	12.50		10	1				
62	Crookston, MN South Main	Distribution		41.60	12.50		25	2				
63	Dawson, Mn Dawson Mills	Distribution		115.00	12.50		10	1				
64	Devils Lake, ND Downtown	Distribution		41.60	4.16		10	1				
65	Enderlin, ND	Distribution		115.00	12.50		14	1				
66	Fairmount, ND	Distribution		115.00	12.50		10	3				
67	Fergus Falls, MN Edgetown	Distribution		115.00	12.50		20	1				
68	Fergus Falls, MN Hoot Lake	Distribution		115.00	12.50		20	1				
69	Fergus Falls, MN South East	Distribution		115.00	12.50		37	1				
70	Gwinner, ND	Distribution		115.00	12.50		20	2				
71	Harvey, ND Northwest	Distribution		115.00	12.50		10	1				
72	Itasca, MN Minnesota Pipeline	Distribution		115.00	4.16		10	1				
73	Jamestown, ND Downtown	Distribution		115.00	12.50		10	1				
74	Jamestown, ND North	Distribution		115.00	12.50		10	1				
75	Jamestown, ND Potato	Distribution		115.00	12.50		10	1				
76	Jamestown, ND Southwest	Distribution		41.60	12.50		10	1				
77	Lake Norden, SD Dairy	Distribution		41.60	12.50		11	1				
78	Lake Norden, SD Dairy	Distribution		115.00	12.50		94	2				
79	Lisbon, ND Town	Distribution		115.00	12.50		14	1				
80	Mahnomen, MN	Distribution		115.00	12.50		10	1				
81	Milbank, SD Northwest	Distribution		41.60	12.50		63	3				
82	Milbank, SD South	Distribution		41.60	12.50		22	1				
83	Morris, MN Northeast	Distribution		41.60	12.50		14	1				
84	Morris, MN South	Distribution		115.00	12.50		10	3				
85	Oakes, ND North	Distribution		41.60	12.50		10	3				
86	Parkers Prairie	Distribution		41.60	12.50		13	1				
87	Pelican Rapids, MN Turkey Plant	Distribution		115.00	12.50		13	1				
88	Perham, MN	Distribution		115.00	12.50		13	2				
89	Rosholt, SD	Distribution		41.60	12.50		11	1				
90	Rugby, ND Northwest	Distribution		41.60	12.50		14	1				
91	Spiritwood, ND	Distribution		115.00	12.50		14	1				
92	Wahpeton Inventory	Distribution		115.00	12.50				1			
93	Wahpeton Inventory	Distribution		115.00	4.16				1			
94	Wahpeton Inventory	Distribution		41.60	4.16				1			
95	Wahpeton Inventory	Distribution		41.60	12.50				1			

96	Wahpeton, ND North 115 kv - 63230	Distribution		115.00	12.50		24	2				
97	Wahpeton, ND Northwest	Distribution		41.60	12.50		22	2				
98	Wheaton, MN South	Distribution		115.00	12.50		14	1				
99	TotalDistributionSubstationMember						801	63	4			
100	TotalTransmissionSubstationMember						4,618	57	4			
101	Total						5,419	120	8		0	0

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

Joint ownership, Otter Tail Power Company, 53.9%; Northwestern Public Service Company, 23%; Montana-Dakota Utilities Company, 22.7%. Expenses are shared on ownership percent basis. Accounts affected are regular accounts applicable to substations. None of the owners are associated companies. Columns C, D and E are reported in KVA.

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Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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**TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES**

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	<b>Non-power Goods or Services Provided by Affiliated</b>			
2	Construction work in progress	Otter Tail Corporation	107	5,889
3	Expenditures for certain civic, political & relat	Otter Tail Corporation	426.4	16,766
4	Dividends declared - common stock	Otter Tail Corporation	438	54,944,395
5	<sup>(b)</sup> Corporate allocated A&G expense	Otter Tail Corporation	See Note	13,328,418
19				
20	<b>Non-power Goods or Services Provided for Affiliated</b>			
21	Printing, design & mailing services	Otter Tail Corporation	417	22,440
22	Other deductions	Otter Tail Corporation	426.5	205,033
23	Printing, design & mailing services	TO Plastics	417	1,400
24	Printing, design & mailing services	BTD Manufacturing	417	8,975
25	Printing, design & mailing services	Northern Pipe Products	417	67
42				

Name of Respondent: Otter Tail Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

Corporate Allocated A&G expenses are allocated in accordance with Otter Tail Corporation's Corporate Cost Allocation Manual as provided by the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, and the South Dakota Public Utilities Commission.

(b) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

The following accounts were charged:

Account	Amount (\$)
500.0	8,252
506.0	23,128
513.0	3,760
920.0	5,266,085
921.0	5,294,578
923.0	1,276,891
924.0	19,146
925.0	197,928
926.0	8,979
930.1	15,815
930.2	888,237
931.0	121,909
935.0	319,751
	13,328,418

[PROTECTED DATA BEGINS...

Docket No. PU-23-  
PU-23-\_2023-06-27\_OTP SLGS Assessment Part 4 of 4\_PUBLIC  
is CONFIDENTIAL  
in its Entirety

...PROTECTED DATA ENDS]