Otter Tail Power Company
Notes to Financial Statements
For the years ended December 31, 2017 and 2016

1. Summary of Significant Accounting Policies

Organization and Operations
Otter Tail Power Company (OTP) was incorporated in 1907 under the laws of the State of Minnesota and is a wholly owned subsidiary of Otter Tail Corporation.

On July 1, 2009, Otter Tail Corporation completed a holding company reorganization whereby OTP, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation. The new parent holding company was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization.

OTP includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota. In addition, OTP is a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets.

OTP provides electricity to more than 130,000 customers in a service area encompassing 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. The territory served by OTP is predominantly agricultural. The aggregate population of OTP’s retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 126,000 people live in communities having a population of more than 1,000, according to the 2010 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,427); Bemidji, Minnesota (13,431); and Fergus Falls, Minnesota (13,138). As of December 31, 2017, OTP served 132,146 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant. One customer accounted for 11.7% of the 2017 revenue from the Electric segment.

Related Party
Included in the amounts presented in the balance sheet and income statement are the following related party balances:

(in thousands)	2017	2016
Accounts Receivable	$ 6	$ 10
Accounts Payable	2,067	1,572
Operating Revenues	31	34
Other Operation and Maintenance Expenses	10,725	9,582

The related party transactions predominately relate to the allocation of corporate overhead expenses and corporate aircraft usage to OTP and rent charged to Otter Tail Corporation for its use of office space in Fergus Falls. The corporate overhead expenses include such items as labor, professional services, office rent, subscriptions, information technology and general office expenses incurred by Otter Tail Corporation.

These expenses are allocated to OTP based on the type of expenditure, using an allocation methodology as defined in Otter Tail Corporation’s Corporate Cost Allocation Manual.

Regulation and Accounting Standards Codification (ASC) Topic 980 (ASC 980)
OTP, a regulated electric utility company, accounts for the financial effects of regulation in accordance with ASC 980. This standard allows for the recording of a regulatory asset or liability for costs and revenues that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, OTP defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 3 for further discussion.

OTP is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC).

Plant, Retirements and Depreciation
Utility 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 on electric utility plant was $741,000 in 2017 and $495,000 in 2016. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal expenses. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. 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 (5 to 82 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.74% in 2017 and 2.88% in 2016. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Recoverability of Long-Lived Assets

OTP reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. OTP determines potential impairment by comparing the carrying amount of the assets with 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, OTP would recognize an impairment loss. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

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 four major in-service transmission lines and one additional major transmission line under construction. The following table provides ownership percentages and amounts included in the OTP's December 31, 2017 and 2016 balance sheets for its share of jointly owned assets in each of these jointly owned facilities:

Jointly Owned Facilities *(dollars in thousands)*	OTP Ownership Percentage	Electric Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Plant
December 31, 2017					
Big Stone Plant	53.9%	$ 329,942	$ 1,074	$ (74,165)	$ 256,851
Coyote Station	35.0%	177,721	158	(103,944)	73,935
Fargo–Monticello 345 kV line	14.2%	78,192	--	(4,667)	73,525
Brookings–Southeast Twin Cities 345 kV line[1]	4.8%	26,269	--	(1,293)	24,976
Bemidji–Grand Rapids 230 kV line	14.8%	16,331	--	(1,753)	14,578
Big Stone South–Brookings 345 kV line[1]	50.0%	53,225	--	(434)	52,791
Big Stone South–Ellendale 345 kV line[1]	50.0%	--	89,980	--	89,980
December 31, 2016					
Big Stone Plant	53.9%	$ 328,809	$ 23	$ (65,665)	$ 263,167
Coyote Station	35.0%	176,315	113	(101,499)	74,929
Fargo–Monticello 345 kV line	14.2%	78,298	--	(3,511)	74,787
Brookings–Southeast Twin Cities 345 kV line[1]	4.8%	26,406	--	(924)	25,482
Bemidji–Grand Rapids 230 kV line	14.8%	16,331	--	(1,573)	14,758
Big Stone South–Brookings 345 kV line[1]	50.0%	--	45,050	--	45,050
Big Stone South–Ellendale 345 kV line[1]	50.0%	--	49,160	--	49,160

[1]*MISO Multi-Value Project (MVP) designation provides for a return on invested funds while under construction under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).*

OTP's share of direct revenue and expenses of the jointly owned facilities is included in operating revenue and expenses in the statements of income.

Coyote Station Lignite Supply Agreement – 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 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 also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets 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 in that they are required to buy the entity 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 OTP is not required to include CCMC in OTP's 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 as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) 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 because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of December 31, 2017 could be as high as $57.1 million, OTP's 35% share of unrecovered costs.

Income Taxes
Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. OTP amortizes investment tax credits over the estimated lives of related property. OTP records income taxes in accordance with ASC Topic 740, *Income Taxes,* and has recognized in its financial statements 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. The term "more-likely-than-not" means a likelihood of more than 50%. OTP classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 11 regarding the OTP's accounting for uncertain tax positions.

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. In OTP's financial statements, comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. In accordance with ASC 740, OTP records separate company deferred tax attribute balances as if OTP filed separate tax returns. OTP's deferred taxes included $2.5 million and $7.9 million of deferred taxes associated with net operating losses that had been utilized by the consolidated group as of December 31, 2017 and 2016, respectively. This deferred tax asset would be reclassified to an intercompany receivable asset in the event the entity were to leave the consolidated return filing group.

OTP also is required to assess the realizability of its deferred tax assets, taking into consideration its forecast of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, valuation allowances against the OTP's deferred tax assets. To the extent facts and circumstances change in the future, adjustments to the valuation allowance may be required.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law. The major impacts of the changes included in the TCJA are discussed in note 11 to the financial statements.

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 in excess of amounts recovered in base rates 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.

Under ASC Topic 815, *Derivatives and Hedging,* OTP accounts for forward energy contracts as derivatives subject to mark-to-market accounting unless those contracts meet the definition of a capacity contract or are not subject to unplanned netting, then OTP accounts for the contracts under the normal purchases and sales exception to mark-to-market accounting.

Use of Estimates
OTP uses 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.

Cash Equivalents
OTP considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

Investments
The following table provides a breakdown of OTP's investments at December 31:

(in thousands)	2017	2016
Cost Method – Economic Development Loan Pools	$ 45	$ 54
Equity Method – Partnership	24	23
Total Investments	$ 69	$ 77

Agreements Subject to Legally Enforceable Netting Arrangements
OTP has certain derivative contracts that are designated as normal purchases and carried at historical cost in the accompanying balance sheet. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. OTP does not offset assets and liabilities under legally enforceable netting arrangements on the face of its balance sheet.

Fair Value Measurements
OTP follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

Inventories
OTP inventories consisting of fuel, materials and supplies are reported at average cost.

Supplemental Disclosures of Cash Flow Information

	As of December 31,	
(in thousands)	2017	2016
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$ 13,433	$ 13,421

(in thousands)	2017	2016
Cash Paid During the Year for:		
Interest (net of amount capitalized)	$ 25,366	$ 24,322
Income Tax Payments	$ 2,348	$ --

New Accounting Standards Pending Adoption

ASU 2014-09—In May 2014 the Financial Accounting Standards Board (FASB) issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Amendments to the ASC in ASU 2014-09, as amended, are effective for fiscal years beginning after December 15, 2017. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. As of December 31, 2017 OTP had reviewed its revenue streams and contracts. Based on review of OTP's revenue streams, OTP has not identified any contracts where the timing of revenue recognition will change as a result of the adoption of the updates in ASU 2016-09. OTP will adopt the updates in ASU 2014-09 on a modified retrospective basis on January 1, 2018, the date of initial application, but will not be recording a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASU 606 have no impact on the timing of revenue recognition for OTP. Adoption of ASU 2014-09 will result in additional disclosures related to the nature, timing and certainty of revenues.

OTP will report adjustments to Alternative Revenue Program (ARP) revenues as a separate line item within revenue on the face of its statement of income. The ARP revenue adjustments are recorded on the basis of recoverable costs incurred and returns earned under rate riders and are not considered revenue from contracts with customers.

ASU 2016-02—In February 2016 the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. OTP has developed a list of all current leases outstanding and continues to review ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and is evaluating transition options. OTP does not currently plan to apply the amendments in ASU 2016-02 to its financial statements prior to 2019.

ASU 2017-07—In March 2017 the FASB issued ASU No. 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07), which is intended to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost. ASC Topic 715, *Compensation—Retirement Benefits* (ASC 715), does not prescribe where the amount of net benefit cost should be presented in an employer's income statement and does not require entities to disclose by line item the amount of net benefit cost that is included in the income statement or capitalized in assets. The amendments in ASU 2017-07 require that an employer report the service cost component of periodic benefit costs in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost as defined in ASC 715 are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The amendments in ASU 2017-07 also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of internally manufactured inventory or a self-constructed asset). The amendments in ASU 2017-07 are effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The amendments will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit cost in assets.

The amendments in ASU 2017-07 deviate significantly from current prescribed ratemaking and regulatory accounting treatment of postretirement benefit costs, which require the capitalization of a portion of all the components of net periodic benefit costs be included in rate base additions and provide for rate recovery of the non-capitalized portion of all of the components of net periodic pension costs as recoverable operating expenses. OTP has assessed the impact adoption of the amendments in ASU 2017-07 will have on its financial statements, financial position and results of operations and OTP has determined the regulatory assets to be established in order to reflect the effect of the required regulatory accounting treatment of the non-service cost components that cannot be capitalized to plant in service under the ASU 2017-07 amendments to GAAP. The non-service cost components of the affected net periodic benefit costs will be reported below the operating income line on OTP's income statement upon adoption of the amendments in ASU 2017-07.

OTP does not plan to adopt the updates in ASU 2017-07 prior to the first quarter of 2018, the required effective period for application of the updates by OTP. OTP's non-service cost components of net periodic post-retirement benefit costs that were capitalized to plant in service in 2017 that would have been recorded as regulatory assets if the amendments in ASU 2017-07 were applicable in 2017 were $0.8 million. OTP's non-service costs components of net periodic postretirement benefit costs included in operating expense that will be included in other income and deductions on adoption of ASU 2017-07 were $5.6 million in 2017 and $5.1 million in 2016.

2. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP's revenues in 2017 and 2016.

Major Capital Expenditure Projects

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345-kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of December 31, 2017 were approximately $90.0 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power–Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line was energized on September 8, 2017. OTP's capitalized costs on this project as of December 31, 2017 were approximately $72.7 million, which includes assets that are 100% owned by OTP.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Reagent Costs

OTP's systemwide costs for reagents are expected to increase to approximately $2.2 million annually through May 2021 when Hoot Lake Plant is expected to be retired. The Minnesota, North Dakota and South Dakota share of costs are approximately 50%, 40% and 10%, respectively. Reagent costs for the Big Stone Plant AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) were initially incurred in 2015 when projects went into service.

Minnesota

2016 General Rate Case—The MPUC rendered its final decision in OTP's 2016 general rate case in March 2017 and issued its written order on May 1, 2017. Pursuant to the order, OTP's allowed rate of return on rate base decreased from 8.61% to 7.5056% and its allowed rate of return on equity decreased from 10.74% to 9.41%. On July 6, 2017 the MPUC denied OTP's request for reconsideration of certain of the MPUC's rulings in the rate case and confirmed its May 1, 2017 order.

The MPUC's order also included: (1) the determination that all costs (including FERC allocated costs and revenues) of the Big Stone South–Brookings and Big Stone South–Ellendale MVP projects will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers, and (2) approval of OTP's proposal to transition rate base, expenses and revenues from Environmental Cost Recovery (ECR) and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates will be used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

Information on interim and final rate increases and interim revenue refunds accrued is detailed in the tables below:

($ in thousands)	Interim Rates Authorized April 14, 2016	Final Rates
Revenue Increase – Annualized based on Test Year Data	$ 16,816	$ 10,471
Revenue Percent Increase	9.56%	5.34%
Return on Rate Base	8.07%	7.5056%
Jurisdictional Rate Base based on Test Year Data	$ 483,000	$ 471,000
Return on Equity	10.40%	9.41%
Based on Equity to Total Capital of	52.50%	52.50%
Debt to Total Capital	47.50%	47.50%

Interim Revenue *(in thousands)*	April 16, 2016 through October 31, 2017
Billed	$ 23,289
Accrued Refund	$ 8,779
Net Interim Revenue	$ 14,510
Interest on Refundable Amount	$ 265
Final Refund	$ 9,044

In addition to the interim rate refund, OTP is required to refund the difference between (1) amounts collected under its Minnesota ECR and TCR riders based on the return on equity (ROE) approved in its most recent rider update and (2) amounts that would have been collected based on the lower 9.41% ROE approved in its 2016 general rate case going back to April 16, 2016, the date interim rates were implemented. As of October 31, 2017 the revenues collected under the Minnesota ECR and TCR riders subject to refund due to the lower ROE rate and other adjustments were $0.9 million and $1.4 million, respectively. These amounts will be refunded to Minnesota customers over a 12-month period through reductions in the Minnesota ECR and TCR rider rates in effect November 1, 2017, as approved by the MPUC. The TCR rate is provisional and subject to revision under a separate docket.

OTP accrued interim and rider rate refunds until final rates became effective, for bills rendered on and after November 1, 2017. The final interim rate refund, including interest, of $9.0 million was applied as a credit to Minnesota customers' electric bills beginning November 17, 2017.

<u>Minnesota Conservation Improvement Programs (MNCIP)</u>—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The Minnesota Department of Commerce's (MNDOC) may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model provides utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism. MNCIP incentives included $5.0 million approved for 2016.

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of $2.6 million in 2017. The 2017 program resulted in an approximate 10% decrease in energy savings compared to 2016 program results. OTP will request approval for recovery of its 2017 MNCIP program costs not included in base rates, a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC by April 1, 2018.

<u>Transmission Cost Recovery Rider</u>—The Minnesota Public Utilities Act (the MPU Act) provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide

service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

In OTP's 2016 general rate case order issued on May 1, 2017, the MPUC ordered OTP to include, in the TCR rider retail rate base, Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment will result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to allocate costs between jurisdictions of the FERC MVP transmission projects in the TCR rider. OTP believes the MPUC-ordered treatment conflicts with federal authority over transmission of electricity in interstate commerce and rates for the transmission of electricity subject to the jurisdiction of the FERC as set forth in the Federal Power Act of 1935, as amended (Federal Power Act). A decision is expected in late 2018.

Environmental Cost Recovery Rider— OTP had an ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant Air Quality Control System (AQCS). The ECR rider provided for a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's 2010 general rate case. In its 2016 general rate case order, the MPUC approved OTP's proposal to transition eligible rate base and expense recovery from the ECR rider to base rate recovery, effective with implementation of final rates in November 2017.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the FCA rider or general rates. In its 2016 general rate case order issued May 1, 2017 the MPUC again denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs or through the FCA rider. Instead, the test-year costs will be recovered in general rates and variability of those costs in excess of amounts included in general rates will only be recovered to the extent actual kilowatt-hour (kwh) sales exceed forecasted kwh sales used to establish general rates.

North Dakota

General Rates—On November 2, 2017 OTP filed a request with the NDPSC for a rate review and an effective increase in annual revenues from non-fuel base rates of $13.1 million or 8.72%. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.30%. On December 20, 2017 the NDPSC approved OTP's request for interim rates to increase annual revenue collections by $12.8 million, effective January 1, 2018. OTP used a lower rate of return on equity in the calculation of interim rates based on the rate of return on equity used in its 2018 test-year rate request. In February 2018, in a proceeding before the NDPSC, OTP's interim rate increase was reduced from $12.8 million to $8.3 million or from 10.44% to 6.79%, effective March 1, 2018. This was in response to a lower revenue requirement related to a reduction in federal corporate income taxes from 35% to 21% in the TCJA.

OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment which enables OTP to recover its North Dakota jurisdictional share of investments in renewable energy facilities. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects. The ECR rider provides for a return on investment at the level approved in OTP’s most recent general rate case and for recovery of OTP’s North Dakota share of reagent and emission allowance costs.

South Dakota

2010 General Rate Case—OTP’s most recent general rate increase in South Dakota of approximately $643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP’s allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities.

Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP’s request to include recovery of these costs in its South Dakota FCA rider.

TCJA

The TCJA reduced the federal corporate income tax rate from 35% to 21%. Currently, all OTP rates have been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC have all initiated dockets or proceedings to begin working with utilities to assess the impact of the lower income tax rates under the TCJA on electric rates, and develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required its regulated utilities to make filings by January 30, 2018 and February 15, 2018, but has not made a determination on rate treatment. The SDPUC required initial comments by February 1, 2018 and indicated that revenues collected subsequent to December 31, 2017 would be subject to refund, pending determination of the impacts of the TCJA. OTP is still assessing these impacts and will continue to work with the respective commissions to determine if any rate adjustments are necessary, and if so, to determine the appropriate timing and approach for making those adjustments.

Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2014 for the rate riders described above:

Rate Rider	R - Request Date A - Approval Date	Effective Date Requested or Approved	Annual Revenue *($000s)*	Rate
Minnesota				
Conservation Improvement Program				
2016 Incentive and Cost Recovery	A – September 15, 2017	October 1, 2017	$ 9,868	$0.00536/kwh
2015 Incentive and Cost Recovery	A – July 19, 2016	October 1, 2016	$ 8,590	$0.00275/kwh
2014 Incentive and Cost Recovery	A – July 10, 2015	October 1, 2015	$ 8,689	$0.00287/kwh
Transmission Cost Recovery				
2017 Rate Reset[1]	A – October 30, 2017	November 1, 2017	$ (3,311)	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	$ 4,736	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	$ 7,203	Various
2014 Annual Update	A – February 18, 2015	March 1, 2015	$ 8,388	Various
Environmental Cost Recovery				
2017 Rate Reset	A – October 30, 2017	November 1, 2017	$ (1,943)	-0.935% of base
2016 Annual Update	A – July 5, 2016	September 1, 2016	$11,884	6.927% of base
2015 Annual Update	A – March 9, 2016	October 1, 2015	$12,104	7.006% of base
North Dakota				
Renewable Resource Adjustment				
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$ 9,989	7.756% of base
2016 Annual Update	A – March 15, 2017	April 1, 2017	$ 9,156	7.005% of base
2015 Annual Update	A – June 22, 2016	July 1, 2016	$ 9,262	7.573% of base
2014 Annual Update	A – March 25, 2015	April 1, 2015	$ 5,441	4.069% of base
Transmission Cost Recovery				
2017 Annual Update	A – November 29, 2017	January 1, 2018	$ 7,959	Various
2016 Annual Update	A – December 14, 2016	January 1, 2017	$ 6,916	Various
2015 Annual Update	A – December 16, 2015	January 1, 2016	$ 9,985	Various
Environmental Cost Recovery				
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$ 8,537	6.629% of base
2017 Annual Update	A – July 12, 2017	August 1, 2017	$ 9,917	7.633% of base
2016 Annual Update	A – June 22, 2016	July 1, 2016	$10,359	7.904% of base
2015 Annual Update	A – June 17, 2015	July 1, 2015	$12,249	9.193% of base
South Dakota				
Transmission Cost Recovery				
2017 Annual Update	A – February 28, 2018	March 1, 2018	$ 1,779	Various
2016 Annual Update	A – February 17, 2017	March 1, 2017	$ 2,053	Various
2015 Annual Update	A – February 12, 2016	March 1, 2016	$ 1,895	Various
2014 Annual Update	A – February 13, 2015	March 1, 2015	$ 1,538	Various
Environmental Cost Recovery				
2017 Annual Update	A – October 13, 2017	November 1, 2017	$ 2,082	$0.00483/kwh
2016 Annual Update	A – October 26, 2016	November 1, 2016	$ 2,238	$0.00536/kwh
2015 Annual Update	A – October 15, 2015	November 1, 2015	$ 2,728	$0.00643/kwh

[1]*Approved on a provisional basis in the Minnesota general rate case docket and subject to revision in a separate docket.*

Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the years ended December 31:

Rate Rider *(in thousands)*	2017	2016
Minnesota		
Conservation Improvement Program Costs and Incentives[1]	$ 9,225	$12,920
Environmental Cost Recovery	8,148	12,443
Transmission Cost Recovery	2,973	5,795
North Dakota		
Environmental Cost Recovery	9,782	11,089
Transmission Cost Recovery	8,729	7,694
Renewable Resource Adjustment	7,620	7,800
South Dakota		
Environmental Cost Recovery	2,345	2,538
Transmission Cost Recovery	1,843	1,820
Conservation Improvement Program Costs and Incentives	598	468

[1]*Includes MNCIP costs recovered in base rates.*

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint 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. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. A non-binding decision by the presiding Administrative Law Judge (ALJ) was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%. A number of parties requested rehearing of the September 2016 order and the requests are pending FERC action.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint 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 from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, which were held the week of February 16, 2016. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. OTP is currently waiting for the issuance of a FERC order on the second complaint.

Based on the probable reduction by the FERC in the ROE component of the MISO Tariff, OTP had a $2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE. MISO processed the refund for the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period in its February and June 2017 billings. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, has resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from $2.7 million on December 31, 2016 to $1.6 million as of December 31, 2017.

In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the two ROE complaints involving MISO transmission owners discussed above. In April 2017 the Court of Appeals for the District of Columbia (D.C. Circuit) vacated and remanded the FERC's June 2014 ROE order in the NETOs' complaint. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. OTP will await the FERC response to the April 2017 action of the D.C. Circuit before determining if an adjustment to its accrued refund liability is required. On September 29, 2017 the MISO transmission owners filed a motion to dismiss the second complaint based on the D.C. Circuit decision in the NETO complaint. If FERC were to act on a motion to dismiss, it would eliminate the refund obligation from the second complaint and the ROE from the first complaint would remain in effect.

3. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on OTP's balance sheets:

	December 31, 2017			Remaining Recovery/ Refund Period
(in thousands)	Current	Long-Term	Total	(months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$ 9,090	$ 112,487	$ 121,577	see below
Conservation Improvement Program Costs and Incentives[2]	7,385	2,774	10,159	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,651	6,651	asset lives
Deferred Marked-to-Market Losses[1]	4,063	2,405	6,468	36
Big Stone II Unrecovered Project Costs – Minnesota[1]	650	1,636	2,286	40
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	--	1,985	1,985	24
Debt Reacquisition Premiums[1]	254	960	1,214	177
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	442	542	65
North Dakota Renewable Resource Rider Accrued Revenues[2]	206	236	442	15
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	309	--	309	12
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	267	--	267	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	152	--	152	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[2]	75	--	75	12
Total Regulatory Assets	$ 22,551	$ 129,576	$ 152,127	
Regulatory Liabilities:				
Deferred Income Taxes	$ --	$ 149,052	$ 149,052	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	83,100	83,100	asset lives
Refundable Fuel Clause Adjustment Revenues	5,778	--	5,778	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,667	--	1,667	11
Minnesota Transmission Cost Recovery Rider Accrued Refund	802	609	1,411	22
Minnesota Renewable Resource Recovery Rider Accrued Refund	409	--	409	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	349	--	349	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	208	--	208	4
South Dakota Environmental Cost Recovery Rider Accrued Refund	187	--	187	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	48	180	24
South Dakota Transmission Cost Recovery Rider Accrued Refund	151	--	151	12
Other	5	84	89	192
Total Regulatory Liabilities	$ 9,688	$ 232,893	$ 242,581	
Net Regulatory Asset/(Liability) Position	$ 12,863	$(103,317)	$ (90,454)	

[1]*Costs subject to recovery without a rate of return.*
[2]*Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.*

(in thousands)	December 31, 2016 Current	Long-Term	Total	Remaining Recovery/ Refund Period (months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$ 6,443	$108,267	$114,710	see below
Conservation Improvement Program Costs and Incentives[2]	4,836	5,158	9,994	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,153	6,153	asset lives
Deferred Marked-to-Market Losses[1]	4,063	6,467	10,530	48
Big Stone II Unrecovered Project Costs – Minnesota[1]	778	2,087	2,865	52
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	333	--	333	12
Debt Reacquisition Premiums[1]	325	1,214	1,539	189
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	543	643	77
North Dakota Renewable Resource Rider Accrued Revenues[2]	1,319	482	1,801	15
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	1,082	--	1,082	12
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	113	--	113	12
Deferred Income Taxes[1]	--	1,014	1,014	asset lives
Recoverable Fuel and Purchased Power Costs[1]	1,798	--	1,798	12
Minnesota Renewable Resource Rider Accrued Revenues[2]	34	--	34	9
North Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	--	568	568	24
South Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	73	141	214	14
Total Regulatory Assets	$ 21,297	$132,094	$153,391	
Regulatory Liabilities:				
Deferred Income Taxes	$ --	$ 818	$ 818	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	80,404	80,404	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	139	--	139	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	757	--	757	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	1,381	782	2,163	24
Revenue for Rate Case Expenses Subject to Refund – Minnesota	711	208	919	16
South Dakota Environmental Cost Recovery Rider Accrued Refund	285	--	285	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	--	132	132	24
Other	21	89	110	204
Total Regulatory Liabilities	$ 3,294	$ 82,433	$ 85,727	
Net Regulatory Asset Position	$ 18,003	$ 49,661	$ 67,664	

[1]*Costs subject to recovery without a rate of return.*
[2]*Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.*

The regulatory liability and asset related to Deferred Income Taxes results from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes*.

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC Topic 715, *Compensation—Retirement Benefits*, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Losses recorded as of December 31, 2017 relate to forward purchases of energy scheduled for delivery through December 2020.

Big Stone II Unrecovered Project Costs – Minnesota are the Minnesota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-ups relate to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-ups also include the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 177 months.

Big Stone II Unrecovered Project Costs – South Dakota are the South Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2017.

North Dakota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's current rate case in North Dakota currently being recovered over a 12-month period beginning with the establishment of interim rates in January 2018.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota currently being recovered over a 24-month period beginning with the establishment of interim rates in April 2016.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and for reagent and emission allowances costs that are recoverable from North Dakota customers as of December 31, 2017.

Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues relate to revenues recorded for fuel and purchased power costs reductions provided to customers in energy intensive trade exposed industries that are subject to recovery from other Minnesota customers.

The Accumulated Reserve for Estimated Removal Costs – Net of Salvage is reduced as actual removal costs, net of salvage revenues, are incurred.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of December 31, 2017.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2017.

The Minnesota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2017.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2017.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relates to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund over a 24-month period beginning with the establishment of interim rates in April 2016.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of December 31, 2017.

The South Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that had not been billed to South Dakota customers as of December 31, 2016.

The South Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that are refundable to South Dakota customers as of December 31, 2017.

If for any reason OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from OTP's balance sheet and included in OTP's statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

4. Common Shareholder's Equity

OTP has issued and outstanding 100 shares of common stock with a par value of $5 per share, with the sole holder of these shares being Otter Tail Corporation. Otter Tail Corporation made cash equity contributions to OTP totaling $0 in 2017 and $37,000,000 in 2016.

5. Retained Earnings and Dividend Restriction

OTP's credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if OTP did not meet certain financial covenants. As of December 31, 2017 OTP was in compliance with these financial covenants. See note 7 for further information on the 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 or the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to Otter Tail Corporation by requiring an equity-to-total-capitalization ratio between 47.4% and 58.0% based on OTP's 2017 capital structure petition approved by order of the MPUC on September 1, 2017. As of December 31, 2017 OTP's equity-to-total-capitalization ratio including short-term debt was 51.4% and its net assets restricted from distribution totaled approximately $471,000,000. Total capitalization for OTP cannot currently exceed $1,178,024,000.

6. Commitments and Contingencies

Construction and Other Purchase Commitments
At December 31, 2017 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately $41.0 million.

Electric Utility Capacity and Energy Requirements and Coal Purchase and Delivery Contracts
OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2041. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Big Stone Plant and Coyote Station expire at the end of 2019 and 2040, respectively. OTP has an agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. OTP has no fixed minimum purchase requirements under the agreement, but all of Hoot Lake Plant's coal requirements for the period covered must be purchased under this agreement. The dollar amounts of OTP's estimated purchase requirements under this agreement are excluded from the table below because OTP has not committed to any minimum level of purchases under the agreement. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they currently provide for recovery of most fuel costs. See table below for schedule of commitments.

Operating Leases
OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. Rent expense from operations was $2,540,000 for 2017 and $2,577,000 for 2016.

The amounts of OTP's construction program and other commitments and commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of December 31, 2017, are as follows:

(in thousands)	Construction Program and Other Commitments	Capacity and Energy Requirements	Coal Purchase Commitments	Operating Leases
2018	$ 27,538	$ 24,424	$ 26,021	$ 1,838
2019	13,479	24,925	23,016	1,435
2020	--	24,844	22,102	1,436
2021	--	12,988	22,537	1,241
2022	--	11,827	22,300	761
Beyond 2022	--	154,310	527,520	8,644
Total	$ 41,017	$ 253,318	$ 643,496	$ 15,355

Contingencies

OTP had a $2.7 million refund liability on its balance sheet as of December 31, 2016 representing its best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on the likelihood of the FERC reducing the ROE component of the MISO Tariff and ordering MISO to refund amounts charged in excess of the lower rate. In the February and June 2017 MISO billings, MISO processed the refund of the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from $2.7 million as of December 31, 2016 to $1.6 million as of December 31, 2017.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders, and the FERC's decision to not resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. OTP is an intervenor in these cases. Final briefs were filed on January 26, 2018. Oral arguments will occur in the spring of 2018. A final decision is not expected until late in 2018. MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, OTP cannot estimate its exposure at this time from a final order reversing the relevant FERC orders, which could have an adverse effect on OTP's results of operations.

Contingencies, by their nature, relate to uncertainties that require OTP's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies that could potentially impact OTP's financial statements are those related to environmental remediation and litigation matters, but no estimates for potential losses have been made at this time, including any liability for RSG charges.

In 2014 the Environmental Protection Agency (EPA) published both proposed standards of performance for carbon dioxide (CO_2) emissions from new, reconstructed and modified fossil fuel-fired power plants (New Source Performance Standards), and proposed CO_2 emission guidelines for existing fossil fuel-fired power plants (the Clean Power Plan) under section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. Both rules were challenged on legal grounds. On February 9, 2016 the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review in the D.C. Circuit. The D.C. Circuit heard oral argument on challenges to the Clean Power Plan on September 27, 2016 before the full court, and a decision was expected in the first half of 2017. However, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, the EPA was directed to consider suspending, revising or rescinding the CO_2 rules discussed above. Thereafter, the EPA issued notices in the Federal Register of its intent to review these rules pursuant to the Executive Order, and it filed motions to stay the pending litigation. The D.C. Circuit subsequently issued orders holding in abeyance the appeals of both the New Source Performance Standards and the Clean Power Plan, pending EPA review. On October 16, 2017 the EPA published a proposed rule to rescind the Clean Power Plan. Therefore, there is uncertainty regarding the future of both rules.

Other
OTP is a party to litigation and regulatory enforcement matters arising in the normal course of business. OTP regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. OTP believes the effect on its results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2017 will not be material.

7. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of OTP's line of credit as of December 31, 2017 and December 31, 2016:

(in thousands)	Line Limit	In Use on December 31, 2017	Restricted due to Outstanding Letters of Credit	Available on December 31, 2017	Available on December 31, 2016
OTP Credit Agreement	$ 170,000	$ 112,371	$ 300	$ 57,329	$ 127,067

Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was $112,371,000 on December 29, 2017 and the average daily balance of debt outstanding during 2017 was $69,391,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2017 was 2.4% compared with 1.8% in 2016. The weighted average interest rate on OTP's short-term debt outstanding on December 31, 2017 was 2.7%.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2017 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt or the issuer rating if a rating is not provided for the senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its 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 OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

2018 Note Purchase Agreement
On November 14, 2017, OTP entered into a Note Purchase Agreement (the 2018 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, $100 million aggregate principal amount of OTP's 4.07% Series 2018A Senior Unsecured Notes due February 7, 2048 (the 2018 Notes). The 2018 Notes were issued on February 7, 2018. Proceeds from the 2018 Notes were used to repay $100 million in outstanding borrowings under the OTP Credit Agreement.

OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the Note Purchase Agreement, any prepayment made by OTP of all of the Notes then outstanding on or after August 7, 2047 will be made without any make-whole amount. The 2018 Note Purchase Agreement also requires OTP to offer to prepay all outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2018 Note Purchase Agreement) of OTP.

The 2018 Note Purchase Agreement contains a number of restrictions on the business of OTP. These include restrictions on OTP's abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2018 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2018 Note

Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2018 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2018 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the 2018 Notes than any analogous provision contained in the 2018 Note Purchase Agreement (Additional Covenant), then unless waived by the Required Holders (as defined in the 2018 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2018 Note Purchase Agreement. The 2018 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

<u>2013 Note Purchase Agreement</u>
On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the purchasers named therein pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The Notes were issued on February 27, 2014.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2013 Note Purchase Agreement) of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (Additional Covenant), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

<u>2007 and 2011 Note Purchase Agreements</u>
On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its $122 million senior unsecured notes issued in three series consisting of $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement). On August 21, 2017 OTP used borrowings under the OTP Credit Agreement to retire the $33 million 5.95%, Series A Senior Unsecured Notes, which had been issued under the 2007 Note Purchase Agreement and matured on August 20, 2017.

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Shelf Registration
On May 11, 2015 Otter Tail Corporation filed a shelf registration statement with the SEC under which it 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, which expires on May 11, 2018.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2017 for each of the next five years are:

(in thousands)	2018	2019	2020	2021	2022
Aggregate Amounts of Debt Maturities	$ --	$ --	$ --	$ 140,000	$ 30,000

Financial Covenants

OTP was in compliance with the financial covenants in their debt agreements as of December 31, 2017.

No Credit or Note Purchase Agreement contains 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.

OTP's borrowing agreements are subject to certain financial covenants. Specifically:

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.
- Under the 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement, OTP may not permit the ratio of its Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.
- Under the 2013 Note Purchase Agreement and the 2018 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, in each case as provided in the related agreement. OTP had no Priority Indebtedness outstanding as of December 31, 2017.

8. Pension Plan and Other Postretirement Benefits

Pension Plan
OTP's noncontributory funded pension plan (the Plan) covers substantially all OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2013, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the Plan. The Plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. OTP reserves the right to discontinue the Plan but no change or discontinuance may affect the pensions theretofore vested.

The pension plan has a trustee who is responsible for pension payments to retirees and a separate pension fund manager responsible for managing the Plan's assets. An independent actuary assists in performing the necessary actuarial valuations for the Plan.

The Plan assets consist of common stock and bonds of public companies, U.S. government securities, 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.

Components of net periodic pension benefit cost:

(in thousands)	2017	2016
Service Cost–Benefit Earned During the Period	$ 5,494	$ 5,386
Interest Cost on Projected Benefit Obligation	13,800	13,854
Expected Return on Assets	(18,768)	(18,987)
Amortization of Prior-Service Cost from Regulatory Asset	120	189
Amortization of Net Actuarial Loss from Regulatory Asset	5,090	5,153
Net Periodic Pension Cost	$ 5,736	$ 5,595

Allocation of Costs:	*2017*	*2016*
Costs included in OTP Capital Expenditures	*$ 1,142*	*$ 1,048*
Costs included in Electric Operation and Maintenance Expenses	*4,594*	*4,547*

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2017	2016
Discount Rate	4.60%	4.76%
Long-Term Rate of Return on Plan Assets	7.50%	7.75%
Rate of Increase in Future Compensation Level	3.00%	3.13%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

(in thousands)	2017	2016
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 21	$ 141
Unrecognized Actuarial Loss	99,360	98,039
Total Regulatory Assets	$ 99,381	$ 98,180
Noncurrent Liability	$ 65,782	$ 58,845

Funded status as of December 31:

(in thousands)	2017	2016
Accumulated Benefit Obligation	$(308,509)	$(274,660)
Projected Benefit Obligation	$(344,253)	$(307,086)
Fair Value of Plan Assets	278,471	248,241
Funded Status	$ (65,782)	$ (58,845)

The following tables provide a reconciliation of the changes in the OTP portion of the fair value of the Plan's assets and the Plan's benefit obligations over the two-year period ended December 31, 2017:

(in thousands)	2017	2016
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 248,241	$ 227,798
Actual Return on Plan Assets	43,312	23,404
Discretionary Company Contributions	--	10,000
Benefit Payments	(13,082)	(12,961)
Fair Value of Plan Assets at December 31	$ 278,471	$ 248,241
Estimated Asset Return	17.8%	10.1%
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 307,086	$ 295,171
Service Cost	5,494	5,386
Interest Cost	13,800	13,854
Benefit Payments	(13,082)	(12,961)
Actuarial Loss	30,955	5,636
Projected Benefit Obligation at December 31	$ 344,253	$ 307,086

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.90%	4.60%
Rate of Increase in Future Compensation Level:		
All participants – prior to 2017		3.00%
Participants to Age 39	4.50%	
Participants Age 40 to Age 49	3.50%	
Participants Age 50 and Older	2.75%	

The assumed rate of return on pension fund assets used for the determination of 2018 net periodic pension cost is 7.50%. The assumed long-term rate of return on plan assets is 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 rate of return on plan asset assumptions are reviewed annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with the pension plan investment advisors, as well as input from actuaries who work with the pension plan and benchmarking to peer companies with similar asset allocation strategies.

Market-related value of plan assets–The expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

Measurement Dates:	2017	2016
Net Periodic Pension Cost	January 1, 2017	January 1, 2016
End of Year Benefit Obligations	January 1, 2017 projected to December 31, 2017	January 1, 2016 projected to December 31, 2016
Market Value of Assets	December 31, 2017	December 31, 2016

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets into the net periodic pension cost in 2018 are:

(in thousands)	2018
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 16
Amortization of Unrecognized Actuarial Loss	7,142
Total Estimated Amortization	$ 7,158

Cash flows–OTP had no minimum funding requirement as of December 31, 2017 but made discretionary plan contributions of $20 million as of February 2018.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

(in thousands)	2018	2019	2020	2021	2022	Years 2023-2027
	$14,245	$14,878	$15,515	$16,180	$16,877	$92,981

The following objectives guide the investment strategy of the Plan:

- 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 (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 Plan must be in the best interest of plan participants and their beneficiaries.
- The primary objective of the Plan is to provide a source of retirement income for its participants and beneficiaries.
- The near-term primary financial objective of the Plan is to improve the funded status of the Plan.
- A secondary financial objective is to minimize pension funding and expense volatility where possible.

The asset allocation strategy developed by the Retirement Plans Administration Committee (the Committee) is based on the current needs of the Plan and the objectives listed above. An asset/liability review is conducted annually or as often as necessary to assess the impact of various asset allocations on funded status and other financial variables. The current needs of the Plan, the overall investment objectives above, the investment preferences and risk tolerance of the Committee and the desired degree of diversification suggest the need for an investment allocation including multiple asset classes.

The asset allocation in the table below contains guideline percentages, at market value, of the total Plan invested in various asset classes. The Permitted Range is a guide and will at times not reflect the actual asset allocation as this will be dictated by market conditions, the independent actions of the Committee and/or Investment Managers and required cash flows to and from the Plan. The Permitted Range anticipates this fluctuation and provides flexibility for the Investment Managers' portfolios to vary around the target without the need for immediate rebalancing. The Investment Manager will proactively monitor the asset allocation and will direct the purchases and sales to remain within the stated ranges.

The policy of the Plan is to invest assets in accordance with the allocations shown below:

	Permitted Range				
Asset Class / PBO Funded Status	**< 85% PBO**	**>=85% PBO**	**>=90% PBO**	**>=95% PBO**	**>=100% PBO**
Equity	39% - 59%	34% - 54%	24% - 44%	14% - 34%	0% - 20%
Investment Grade Fixed Income	22% - 42%	30% - 50%	40% - 60%	53% - 73%	70% - 100%
Below Investment Grade Fixed Income*	0% - 15%	0% - 15%	0% - 15%	0% - 10%	0% - 10%
Other**	5% - 20%	5% - 20%	5% - 20%	0% - 15%	0% - 15%

** Includes (but not limited to) High Yield Bond Fund and Emerging Markets Debt funds.*
*** Other category may include cash, alternatives, and/or other investment strategies that may be classified other than equity or fixed income, such as the Dynamic Asset Allocation fund.*

OTP's pension plan asset allocations at December 31, 2017 and 2016, by asset category are as follows:

Asset Allocation	2017	2016
Large Capitalization Equity Securities	23.5%	21.4%
International Equity Securities	18.1%	22.0%
Small and Mid-Capitalization Equity Securities	8.7%	9.0%
Emerging Markets Equity Fund	5.5%	0.0%
SEI Dynamic Asset Allocation Fund	5.0%	5.4%
Equity Securities	60.8%	57.8%
Fixed-Income Securities and Cash	35.2%	34.3%
Other – SEI Energy Debt Collective Fund	4.0%	4.1%
Other – SEI Special Situation Collective Investment Trust	0.0%	3.8%
	100.0%	100.0%

The following table presents OTP's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy and assets measured using the net asset value (NAV) practical expedient to fair valuation as of December 31:

(in thousands)	2017	2016
Assets in Level 1 of the Fair Value Hierarchy	$ 267,423	$ 228,680
SEI Energy Debt Collective Fund at NAV	11,048	10,190
SEI Special Situation Collective Investment Trust Fund at NAV	--	9,371
Total Assets	$ 278,471	$ 248,241

Fair Value Measurements of Pension Fund Assets
ASC 715, *Compensation – Retirement Benefits,* requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35.

The following table presents OTP's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy as of December 31:

(in thousands)	2017	2016
Large Capitalization Equity Securities Mutual Fund	$ 65,339	$ 53,175
International Equity Securities Mutual Funds	50,397	54,574
Small and Mid-Capitalization Equity Securities Mutual Fund	24,252	22,459
Emerging Markets Equity Fund	15,444	--
SEI Dynamic Asset Allocation Mutual Fund	14,026	13,295
Fixed Income Securities Mutual Funds	97,964	85,174
Cash Management – Money Market Fund	1	3
Total Assets	$ 267,423	$ 228,680

The investments held by the SEI Energy Debt Collective Fund on December 31, 2017 and 2016 consist mainly of below investment grade high yielding 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. Fund assets totaling $10.0 million were invested in the SEI Energy Debt Fund in July 2015. 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). The fund's assets are valued as of the close of business on the last business day of each calendar month and are available 30 days after the end of a calendar quarter. 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, as determined by the investment manager in its sole discretion. Otter Tail Corporation reviews and verifies the reasonableness of the year-end valuations.

Executive Survivor and Supplemental Retirement Plan (ESSRP)
The ESSRP is an unfunded, nonqualified benefit plan for Otter Tail Corporation and OTP executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

The following table lists components of net periodic pension benefit cost for the year ended December 31:

(in thousands)	2017	2016
Service Cost–Benefit Earned During the Period	$ 94	$ 87
Interest Cost on Projected Benefit Obligation	763	782
Amortization of Prior Service Cost:		
From Regulatory Asset	16	16
From Other Comprehensive Income[1]	15	15
Amortization of Net Actuarial Loss:		
From Regulatory Asset	285	293
From Other Comprehensive Income[1]	265	272
Net Periodic Pension Cost[2]	$ 1,438	$ 1,465

[1]*Amortization of Prior Service Costs and Net Actuarial Loss from Other Comprehensive Income Charged to Electric Operation and Maintenance Expenses*
[2]*ESSRP costs are not capitalized*

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2017	2016
Discount Rate	4.60%	4.76%
Rate of Increase in Future Compensation Level	3.00%	3.25%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

(in thousands)	2017	2016
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 40	$ 58
Unrecognized Actuarial Loss	3,229	2,890
Total Regulatory Assets	$ 3,269	$ 2,948
Projected Benefit Obligation Liability – Net Amount Recognized	$(18,380)	$(17,263)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	$ 40	$ 54
Unrecognized Actuarial Loss	3,229	2,682
Total Accumulated Other Comprehensive Loss	$ 3,269	$ 2,736

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2017 and a statement of the funded status as of December 31 of both years:

(in thousands)	2017	2016
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,175	1,188
Benefit Payments	(1,175)	(1,188)
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 17,263	$ 17,107
Service Cost	94	87
Interest Cost	763	782
Benefit Payments	(1,175)	(1,188)
Actuarial Loss	1,435	475
Projected Benefit Obligation at December 31	$ 18,380	$ 17,263

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.85%	4.60%
Rate of Increase in Future Compensation Level	2.75%	3.00%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2018 are:

(in thousands)	2018
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 16
Amortization of Unrecognized Actuarial Loss	267
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	16
Amortization of Unrecognized Actuarial Loss	267
Total Estimated Amortization	$ 566

Cash flows–The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

(in thousands)	2018	2019	2020	2021	2022	Years 2023-2027
	$1,373	$1,416	$1,380	$1,339	$1,297	$5,828

Other Postretirement Benefits

OTP provides a portion of health insurance and life insurance benefits for retired OTP employees. Substantially all of OTP's electric utility employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. There are no plan assets. The following table lists components of net periodic postretirement benefit cost for the year ended December 31:

(in thousands)	2017	2016
Service Cost–Benefit Earned During the Period	$ 1,391	$ 1,270
Interest Cost on Projected Benefit Obligation	2,647	2,443
Amortization of Prior Service Cost from Regulatory Asset	(4)	134
Amortization of Net Actuarial Loss from Regulatory Asset	936	379
Net Periodic Postretirement Benefit Cost	$ 4,970	$ 4,226
Effect of Medicare Part D Subsidy	$ (547)	$ (901)

Allocation of Cost:	*2017*	*2016*
Cost included in OTP Capital Expenditures	*$ 989*	*$ 792*
Cost included in Electric Operation and Maintenance Expenses	*3,981*	*3,433*

Weighted average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2017	2016
Discount Rate	4.46%	4.57%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

(in thousands)	2017	2016
Regulatory Asset:		
Unrecognized Prior Service Cost	$ --	$ (4)
Unrecognized Net Actuarial Loss	18,927	13,586
Net Regulatory Asset	$ 18,927	$ 13,582
Projected Benefit Obligation Liability – Net Amount Recognized	$ (68,100)	$ (61,070)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2017:

(in thousands)	2017	2016
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Company Contributions	3,284	2,832
Benefit Payments (Net of Medicare Part D Subsidy)	(6,512)	(5,888)
Participant Premium Payments	3,228	3,056
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 61,070	$ 47,512
Service Cost (Net of Medicare Part D Subsidy)	1,391	1,270
Interest Cost (Net of Medicare Part D Subsidy)	2,647	2,443
Benefit Payments (Net of Medicare Part D Subsidy)	(6,512)	(5,888)
Participant Premium Payments	3,228	3,056
Actuarial Loss	6,276	12,677
Projected Benefit Obligation at December 31	$ 68,100	$ 61,070

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.81%	4.46%

Assumed healthcare cost-trend rates as of December 31:

	2017	2016
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	5.85%	6.01%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.03%	6.23%
Rate to Which the Cost-Trend Rate is Assumed to Decline	4.50%	4.50%
Year the Rate Reaches the Ultimate Trend Rate	2038	2038

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2017 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 9,078	$ (7,507)
Effect on Total of Service and Interest Cost	$ 714	$ (587)
Effect on Expense	$ 1,551	$ (1,464)

Measurement Dates:	2017	2016
Net Periodic Postretirement Benefit Cost	January 1, 2017	January 1, 2016
End of Year Benefit Obligations	January 1, 2017 projected to December 31, 2017	January 1, 2016 projected to December 31, 2016

The estimated net amounts of unrecognized accumulated actuarial losses to be amortized from regulatory assets into the net periodic postretirement benefit cost in 2018 is $1,649,000.

Cash flows–OTP expects to contribute $3.9 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2018. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately $406,000 in 2018. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2018	2019	2020	2021	2022	Years 2023-2027
	$3,890	$4,009	$4,033	$4,116	$4,223	$20,583

401K Plan

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled $2,381,000 for 2017 and $2,229,000 for 2016.

Employee Stock Ownership Plan

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were $612,000 for 2017 and $647,000 for 2016.

9. Fair Value of Financial Instruments

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

Cash Equivalents—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balance outstanding as of December 31, 2017 and 2016 under the OTP Credit Agreement was subject to a variable interest rate of LIBOR plus 1.25%, which approximates a market rate.

Long-Term Debt including Current Maturities—The fair value of OTP's long-term debt is estimated based on the current market indications of rates available to OTP for the issuance of debt. The fair value measurements of OTP's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820.

	December 31, 2017		December 31, 2016	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Short-Term Debt	$ (112,371)	$ (112,371)	$ (42,883)	$ (42,883)
Long-Term Debt including Current Maturities	(410,316)	(467,496)	(443,139)	(493,598)

10. Property, Plant and Equipment

(in thousands)	December 31, 2017	December 31, 2016	Service Life Range *(years)*	
Electric Plant			Low	High
Production	$ 897,732	$ 891,330	9	82
Transmission	500,352	410,679	42	70
Distribution	482,867	466,285	5	68
General	100,067	92,063	5	50
Electric Plant in Service	1,981,018	1,860,357		
Construction Work in Progress	132,556	149,997		
Other Property - Land	580	880		
Total Plant	2,114,154	2,011,234		
Less Accumulated Depreciation and Amortization	662,431	622,657		
Net Plant	$ 1,451,723	$ 1,388,577		

11. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2017 and 2016) to net income before total income tax expense for the following reasons:

(in thousands)	2017	2016
Tax Computed at Federal Statutory Rate	$ 23,261	$ 23,168
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	2,769	2,499
Differences Reversing in Excess of Federal Rates	551	77
Federal Production Tax Credit	(7,527)	(7,175)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Dividend Received/Paid Deduction	(509)	(537)
Investment Tax Credit Amortization	(164)	(350)
Allowance for Funds Used During Construction - Equity	(322)	(280)
Effect of TCJA	458	--
Permanent and Other Differences	(654)	(186)
Total Income Tax Expense	$ 17,013	$ 16,366
Overall Effective Federal and State Income Tax Rate	25.6%	24.7%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	$ (291)	$ (57)
Current State Income Taxes	784	604
Deferred Federal Income Taxes	21,583	20,953
Deferred State Income Taxes	3,478	3,241
Federal Production Tax Credit	(7,527)	(7,175)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Investment Tax Credit Amortization	(164)	(350)
Total	$ 17,013	$ 16,366
Total Income Before Income Taxes	$ 66,459	$ 66,195

OTP's deferred tax assets and liabilities were composed of the following on December 31:

(in thousands)	2017	2016
Deferred Tax Assets		
Federal Production Tax Credits (PTCs)	$ 40,625	$ 33,113
Regulatory Tax Liabilities	39,465	2,422
North Dakota Wind Tax Credits	32,962	32,962
Retirement Benefit Liabilities	31,894	38,390
Cost of Removal	21,800	31,636
Benefit Liabilities	19,626	28,332
Differences Related to Property	5,420	8,255
Net Operating Loss Carryforward	3,146	9,035
Vacation Accrual	1,142	1,727
Investment Tax Credits	515	818
Other	--	782
Total Deferred Tax Assets	$ 196,595	$ 187,472
Deferred Tax Liabilities		
Differences Related to Property	$(243,760)	$(351,366)
Retirement Benefit Regulatory Asset	(31,894)	(38,390)
Excess Tax over Book Pension	(14,077)	(15,509)
North Dakota Wind Tax Credits	(4,112)	(3,654)
Other	(4,693)	(11,559)
Impact of State Net Operating Losses on Federal Taxes	(483)	(888)
Total Deferred Tax Liabilities	$(299,019)	$(421,366)
Deferred Income Taxes	$(102,424)	$(233,894)

Federal PTCs are earned as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 4.4% in 2017 compared with 2016. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Schedule of expiration of tax credits and tax net operating losses available as of December 31, 2017:

(in thousands)	Amount	2029-37	2038-43
United States			
Federal Net Operating Losses	$ 845	$ 845	$ --
Federal Tax Credits	40,625	40,625	--
State Net Operating Losses	2,301	2,301	--
State Tax Credits	32,962	--	32,962

The following table summarizes the activity related to OTP's unrecognized tax benefits:

(in thousands)	2017	2016
Balance on January 1	$ 411	$ 468
(Decreases) Increases Related to Tax Positions for Prior Years	(291)	40
Increases Related to Tax Positions for Current Year	--	--
Uncertain Positions Resolved During Year	--	(97)
Balance on December 31	$ 120	$ 411

The balance of unrecognized tax benefits as of December 31, 2017 would reduce the OTP's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2017 is not expected to change significantly within the next 12 months. OTP classifies interest and penalties on tax uncertainties as components of the provision for income taxes in the statement of income. There was no amount accrued for interest on tax uncertainties as of December 31, 2017.

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, 2017, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing authorities for tax years prior to 2014 for federal and North Dakota state income taxes and for years prior to 2013 for Minnesota state income taxes.

TCJA

In December 2017 the TCJA was enacted. The TCJA includes a number of changes to existing U.S. tax laws that impact OTP, most notably a reduction of the federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017.

OTP measures deferred tax assets and liabilities using enacted tax rates that will apply in the years in which the temporary differences are expected to be recovered or paid. Accordingly, OTP's deferred tax assets and liabilities were remeasured to reflect the reduction in the U.S. corporate income tax rate from 35% to 21%. The revaluation for OTP required the creation of a regulatory liability and an offsetting reduction in deferred tax liability. This regulatory liability will generally be amortized over the remaining life of the related assets. The revaluation resulted in a one-time, non-cash, income tax expense of approximately $0.5 million in 2017. The impacts of the TCJA adjustments to deferred taxes and regulatory liabilities are provided in the reconciliation below:

(in thousands)	Deferred Tax Liability	Deferred Tax Regulatory Liability
Balance on January 1, 2017	$ 233,894	$ 818
Change due to 2017 Accruals and Amortizations	15,930	376
TCJA Deferred Tax Valuation Adjustment	(109,072)	109,072
Tax Effect on TCJA Deferred Tax Valuation Adjustment	(38,786)	38,786
TCJA Adjustment to Income Tax Expense	458	--
Balance on December 31, 2017	$ 102,424	$ 149,052

OTP recognized the income tax effects of the TCJA in its 2017 financial statements in accordance with Staff Accounting Bulletin No. 118, which provides SEC staff guidance for the application of ASC Topic 740, *Income Taxes*, in the reporting period in which the TCJA was signed into law. Current estimates may be revised and are subject to change due, in part, to complexities and uncertainties associated with the TCJA. While OTP is able to make reasonable estimates of the impact of the TCJA for the reduction in the federal corporate tax rate, consequences on OTP's regulatory liabilities and, the final impact of the TCJA may differ from these estimates due to, among other things, changes in OTP's interpretations and assumptions and additional guidance that may be issued by the U.S. Internal Revenue Service, rate regulators or the FASB.

12. Asset Retirement Obligations (AROs)

OTP's AROs are related to its coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. OTP has 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. OTP has no assets legally restricted for the settlement of any of its AROs.

OTP recorded no new AROs in 2017.

Reconciliations of carrying amounts of the present value of OTP's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2017 and 2016 are presented in the following table:

(in thousands)	2017	2016
Asset Retirement Obligations		
Beginning Balance	$ 8,341	$ 8,084
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(103)
Accrued Accretion	378	360
Settlements	--	--
Ending Balance	$ 8,719	$ 8,341
Asset Retirement Costs Capitalized		
Beginning Balance	$ 2,983	$ 3,086
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(103)
Settlements	--	--
Ending Balance	$ 2,983	$ 2,983
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$ 795	$ 673
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	120	122
Settlements	--	--
Ending Balance	$ 915	$ 795
Settlements	None	None
Original Capitalized Asset Retirement Cost - Retired	$ --	$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	$ --	$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	$ --	$ --