TUCSON ELECTRIC POWER CO
Form 10-K
February 15, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission File Number 1-5924
TUCSON ELECTRIC POWER COMPANY
(Exact name of registrant as specified in its charter)

Arizona (State or other jurisdiction of incorporation or organization)	86-0062700 (I.R.S. Employer Identification No.)

88 East Broadway Boulevard, Tucson, AZ 85701
(Address of principal executive offices)(Zip Code)
Registrant's telephone number, including area code: (520) 571-4000
Securities registered pursuant to Section 12(b) of the Exchange Act: None
Securities registered pursuant to Section 12(g) of the Exchange Act: Common Stock, No Par Value (Title of Class)
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes o No x
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act). Yes o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filero	Accelerated Filero	Non-Accelerated Filerx (do not check if a smaller reporting company)	Smaller Reporting Companyo	Emerging Growth Companyo

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates: None

As of February 14, 2018, Tucson Electric Power Company had 32,139,434 shares of common stock, no par value, outstanding, all of which were held by UNS Energy Corporation, an indirect wholly owned subsidiary of Fortis Inc.

Documents incorporated by reference: None

Tucson Electric Power meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is, therefore, filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

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PART III

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DEFINITIONS

The abbreviations and acronyms used in the 2017 Form 10-K are defined below:

2010 Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2017 Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective on February 27, 2017
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
BBtu	Billion British thermal unit(s)
DG	Distributed Generation
DSM	Demand Side Management
EE Standards	Energy Efficiency Standards
EPA	Environmental Protection Agency
EPNG	El Paso Natural Gas Company, LLC.
FERC	Federal Energy Regulatory Commission
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada, whose principal executive offices are located at Fortis Place, Suite 1100, 5 Springdale Street, St. John's, NL A1E 0E4
Four Corners	Four Corners Generating Station
GAAP	Generally Accepted Accounting Principles in the United States of America
Gila River	Gila River Generating Station
GWh	Gigawatt-hour(s)
kV	Kilo-volt(s)
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery Mechanism
LOC	Letter(s) of Credit
Luna	Luna Generating Station
MMBtu	Million British thermal units
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
NBV	Net Book Value
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
PV	Photovoltaic
REC	Renewable Energy Credit
Regional Haze Rules	Rules promulgated by the EPA to improve visibility at national parks and wilderness areas
RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility recovery of its cost of providing services and an opportunity to earn a reasonable return on its investment
RICE	Reciprocating Internal Combustion Engine
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction

SES	Southwest Energy Solutions, Inc.
SJCC	San Juan Coal Company
SNCR	Selective Non-Catalytic Reduction

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Springerville	Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
TCJA	On December 22, 2017, the Tax Cuts and Jobs Act was signed into law enacting significant changes to the Internal Revenue Code including a reduction in the U.S. federal corporate income tax rate from 35% to 21% effective for tax years beginning after 2017
TEP	Tucson Electric Power Company, the principal subsidiary of UNS Energy Corporation
Third-Party Owners	Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners)
TSA	Transmission Service Agreement
Tri-State	Tri-State Generation and Transmission Association, Inc.
UES	UniSource Energy Services, Inc., a wholly-owned subsidiary of UNS Energy Corporation, and the intermediate holding company established to own the operating companies UNS Electric, Inc. and UNS Gas, Inc.
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy Corporation
UNS Energy	UNS Energy Corporation, the parent company of TEP, whose principal executive offices are located at 88 East Broadway Boulevard, Tucson, Arizona 85701
UNS Energy Affiliates	Affiliated subsidiaries of UNS Energy Corporation including UniSource Energy Services Inc., UNS Electric, Inc., UNS Gas, Inc., and Southwest Energy Solutions, Inc.
UNS Gas	UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy

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FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. Tucson Electric Power Company (TEP or the Company) is including the following cautionary statements to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by TEP in this Annual Report on Form 10-K. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events, future economic conditions, future operational or financial performance and underlying assumptions, and other statements that are not statements of historical facts. Forward-looking statements may be identified by the use of words such as anticipates, believes, estimates, expects, intends, may, plans, predicts, potential, projects, would, and similar expressions. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All such forward-looking statements, whether written or oral, and whether made by or on behalf of TEP, are expressly qualified by these cautionary statements and any other cautionary statements which may accompany the forward-looking statements. In addition, TEP disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report, except as may otherwise be required by the federal securities laws.

Forward-looking statements involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed therein. We express our estimates, expectations, beliefs, and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management’s estimates, expectations, beliefs, or projections will be achieved or accomplished. We have identified the following important factors that could cause actual results to differ materially from those discussed in our forward-looking statements. These may be in addition to other factors and matters discussed in: Part I, Item 1A. Risk Factors; Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations; and other parts of this report. These factors include: state and federal regulatory and legislative decisions and actions, including changes in tax policies; changes in, and compliance with, environmental laws and regulatory decisions and policies that could increase operating and capital costs, reduce generating facility output or accelerate generation facility retirements; regional economic and market conditions which could affect customer growth and energy usage; changes in energy consumption by retail customers; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets and bank markets; the performance of the stock market and a changing interest rate environment, which affect the value of our pension and other postretirement benefit plan assets and the related contribution requirements and expenses; the potential inability to make additions to our existing high voltage transmission system; unexpected increases in operations and maintenance expense; resolution of pending litigation matters; changes in accounting standards; changes in our critical accounting policies and estimates; the ongoing impact of mandated energy efficiency and distributed generation initiatives; changes to long-term contracts; the cost of fuel and power supplies; the ability to obtain coal from our suppliers; cyber-attacks, data breaches, or other challenges to our information security, including our operations and technology systems; the performance of TEP's generation facilities; and the impact of the Tax Cuts and Jobs Act on our financial condition and results of operations, including the assumptions we made relating thereto.

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PART I

ITEM 1. BUSINESS

OVERVIEW OF BUSINESS

General

TEP and its predecessor companies have served the greater Tucson metropolitan area for 125 years. TEP was incorporated in the State of Arizona in 1963. TEP is a regulated electric utility company serving approximately 422,000 retail customers. TEP’s service territory covers 1,155 square miles and includes a population of over one million people in Pima County, as well as parts of Cochise County. TEP's principal business operations include generating, transmitting, and distributing electricity to its retail customers. In addition to retail sales, TEP sells electricity, transmission, and ancillary services to other utilities, municipalities, and energy marketing companies on a wholesale basis. TEP is subject to comprehensive state and federal regulation. The regulated electric utility operation is TEP's only segment.

TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. In 2014, UNS Energy was acquired by Fortis Inc. (Fortis) and became an indirect wholly owned subsidiary of Fortis which is a leader in the North American electric and gas utility business.

Regulated Utility Operations

TEP delivers electricity to retail customers in southern Arizona. TEP owns or has contracts for coal, natural gas, wind, and solar generation resources to provide electricity. This electricity, together with electricity purchased on the wholesale market, is delivered over transmission lines which are part of the Western Interconnection, a regional grid in the United States. The electricity is then transformed to lower voltages and delivered to customers through TEP's distribution system.

TEP operates under a certificate of public convenience and necessity as regulated by the Arizona Corporation Commission (ACC), under which TEP is obligated to provide electricity service to customers within its service territory. The ACC establishes rates that are designed to allow a regulated utility recovery of its cost of providing services and an opportunity to earn a reasonable return on its investment (Retail Rates).

Customers

Electricity sold to retail and wholesale customers by class of customer and the average number of retail customers over the last three years were as follows:

(sales in GWh)	2017		2016		2015	
Electric Sales						
Residential	3,786	28 %	3,724	29 %	3,724	28 %
Commercial	2,192	17 %	2,139	17 %	2,124	15 %
Industrial, non-Mining	1,939	15 %	2,006	16 %	2,063	15 %
Industrial, Mining	991	8 %	997	8 %	1,109	8 %
Other	18	— %	30	— %	33	— %
Total Retail Sales by Customer Class	8,926	68 %	8,896	70 %	9,053	66 %
Wholesale Sales, Long-Term	587	4 %	463	4 %	750	5 %
Wholesale Sales, Short-Term	3,630	28 %	3,308	26 %	3,928	29 %
Total Electric Sales	13,143	100%	12,667	100%	13,731	100%
Average Number of Retail Customers						
Residential	381,399	90 %	378,991	90 %	376,439	90 %
Commercial	38,564	9 %	38,403	9 %	38,253	9 %
Industrial, non-Mining	520	— %	580	— %	588	— %
Industrial, Mining	4	— %	4	— %	4	— %

Other	1,879	1 %	1,866	1 %	1,857	1 %
Total Retail Customers	422,366	100%	419,844	100%	417,141	100%

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Retail Customers

TEP provides electric utility service to a diverse group of residential, commercial, industrial, and public sector customers. Major industries served include copper mining, cement manufacturing, defense, healthcare, education, military bases, and other governmental entities. TEP's retail sales are influenced by several factors including economic conditions, seasonal weather patterns, Demand Side Management (DSM) initiatives and the increasing use of energy-efficient products, and customer-sited Distributed Generation (DG).

Local, regional, and national economic factors impact the growth in the number of customers in TEP's service territory. In each of the past five years, TEP's average number of retail customers increased by less than 1%. TEP expects the number of retail customers to increase at a rate of approximately 1% in 2018 based on the estimated population growth in its service territory.

TEP's retail sales volume in 2017 was 8,926 gigawatt-hours (GWh), which is a decrease of 3.8% from 2013 levels. During the past five years, mining load reductions and state requirements to reduce retail sales through energy efficiency and DG have resulted in lower sales volumes.

TEP's mining customers make up 11% of total retail sales. TEP's GWh sales to mining customers depend on a variety of factors including commodity prices, electricity prices, and the mines' development of self-generating resources. TEP's GWh sales to mining customers decreased by 8% from 2013 levels as a result of the decline in commodity prices requiring the mines to curtail production starting in 2016. TEP cannot predict future commodity prices or the impact they will have on mining production.

Wholesale Customers

TEP's utility operations include the wholesale marketing of electricity to other utilities and power marketers. Wholesale sales transactions are made on both a firm and interruptible basis. A firm contract requires TEP to supply power on demand (except under limited emergency circumstances), while an interruptible contract allows TEP to stop supplying power under defined conditions.

Generally, TEP commits to future sales based on expected generation capability, forward prices, and generation costs using a diversified portfolio approach to provide a balance between long-term, mid-term, and spot energy sales. TEP's wholesale sales consist primarily of two types:

Long-Term Wholesale Sales

Contracts for long-term wholesale sales cover periods of one year or greater. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers.

TEP's long-term wholesale contract with Shell Energy North America expired in 2017. TEP's primary long-term wholesale sale contracts are presented in the table below:

Counterparty	Contracts Expire December 31,
Navajo Tribal Utility Authority	2022
TRICO Electric Cooperative	2024
Navopache Electric Cooperative	2041

Short-Term Wholesale Sales

Certain contracts for short-term wholesale sales cover periods of less than one year and obligate TEP to sell capacity or power at a fixed price. TEP also engages in short-term sales by selling power in the daily or hourly markets at fluctuating spot market prices and making other non-firm power sales. The majority of our revenues from short-term wholesale sales are passed through to TEP's retail customers offsetting fuel and purchased power costs. TEP uses short-term wholesale sales as part of its hedging strategy to reduce customer exposure to fluctuating power prices.

Competition

Retail Customers

TEP is the primary electric service provider to retail customers within its service territory and operates under a certificate of public convenience and necessity as regulated by the ACC.

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Wholesale Customers

The Federal Energy Regulatory Commission (FERC) regulates rates for wholesale power sales and transmission services. TEP engages in long-term wholesale sales to optimize its generation resources. As a result of its wholesale power activity, TEP competes with other utilities, power marketers, and independent power producers in the wholesale markets.

Generation Facilities

As of December 31, 2017, TEP owned 2,531 megawatts (MW) of nominal generation capacity, as set forth in the following table. Nominal capacity is based on unit design net output and measured in alternating current (AC) except for the solar generation which is measured in direct current (DC).

	Unit		Date	Resource	Capacity	Operating	TEP's Share	
Generation Source	No.	Location	In Service	Type	MW	Agent	%	MW
Springerville	1	Springerville, AZ	1985	Coal	387	TEP	100	387
Springerville (1)	2	Springerville, AZ	1990	Coal	406	TEP	100	406
San Juan	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
Navajo (2)	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo (2)	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo (2)	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners	4	Farmington, NM	1969	Coal	785	APS	7.0	55
Four Corners	5	Farmington, NM	1970	Coal	785	APS	7.0	55
Gila River	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	75.0	413
Luna	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt (3)	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100	81
Sundt (3)	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100	81
Sundt	3	Tucson, AZ	1962	Gas	104	TEP	100	104
Sundt	4	Tucson, AZ	1967	Gas	156	TEP	100	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100	50
DeMoss Petrie		Tucson, AZ	2001	Gas	75	TEP	100	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100	94
Springerville		Springerville, AZ	2002-2014	Solar	16	TEP	100	16
Tucson		Tucson, AZ	2010-2014	Solar	13	TEP	100	13
Ft. Huachuca		Ft. Huachuca, AZ	2014-2017	Solar	22	TEP	100	22
Total TEP Capacity (4)								2,531

(1) Springerville Generating Station (Springerville) Unit 2 is owned by San Carlos Resources, Inc., a wholly-owned subsidiary of TEP.

(2) TEP, along with the other participants at the Navajo Generating Facility (Navajo), plan to discontinue operations of Navajo Units 1-3 by the end of 2019.

(3) TEP plans to discontinue operations of Sundt Units 1 & 2 by the end of 2020.

(4) On December 20, 2017, San Juan Generating Station (San Juan) Unit 2 was removed from service. TEP's 50% share of San Juan Unit 2's nominal capacity was 170 MW.

Springerville Generating Station

TEP's other interests in Springerville include: (i) undivided interests in certain common facilities at Springerville (Springerville Common Facilities) made up of 67.8% of ownership interest and 32.2% of leased interest, that includes assets such as, but not limited to: administration building, roads, and well fields used to serve all four units at

Springerville that cannot be proportioned to each unit; and (ii) an 82.95% ownership interest in the Springerville Coal Handling Facilities.

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Springerville Common Facilities Leases

As of December 31, 2017, TEP holds two leveraged lease arrangements related to a 32.2% undivided interest in Springerville Common Facilities. The lease arrangements are scheduled to expire in January 2021 and have fair market value renewal options as well as fixed-price purchase options totaling $68 million.

See Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding the capital leases.

Springerville Units 3 and 4

Springerville Units 3 and 4 are each approximately 400 MW coal-fired generation facilities that are operated but not owned by TEP. These facilities are located at the same site as Springerville Units 1 and 2. The lessee of Springerville Unit 3 compensates TEP for operating the facilities and pays an allocated portion of the fixed costs related to the Springerville Common Facilities and Springerville Coal Handling Facilities. The owner of Springerville Unit 4 owns 17.05% of the Springerville Coal Handling Facilities and pays TEP for a portion of the fixed costs allocated for the common facilities.

Renewable Energy Resources

The ACC's Renewable Energy Standard (RES) requires Arizona regulated utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements by 2025, with DG accounting for 30% of the annual renewable energy requirement. Arizona utilities must file an annual RES implementation plan for review and approval by the ACC. TEP plans to meet these requirements through a combination of utility-owned resources, Power Purchase Agreements (PPAs), and customer-sited DG. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K and Rates and Regulations below for additional information regarding RES.

Owned Renewable Resources

As of December 31, 2017, TEP owned 51 MW of photovoltaic (PV) solar generation capacity measured in DC. The solar generation facilities are located on properties held under land easements and leases.

Renewable Power Purchase Agreements

As of December 31, 2017, TEP had renewable PPAs for 198 MW measured in DC from solar resources, 80 MW measured in AC from wind resources and 4 MW measured in AC associated with the purchase of landfill gas. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future date.

Purchased Power

TEP purchases power from other utilities and power marketers. TEP may enter into contracts to purchase: (i) power under long-term contracts to serve retail load and long-term wholesale contracts; (ii) capacity or power during periods of planned outages or for peak summer load conditions; and (iii) power for resale to certain wholesale customers under load and resource management agreements. See Note 7 of Notes to Consolidated Financial Statements related to the commitment amount of purchased power in Part II, Item 8 of this Form 10-K.

TEP typically uses its generation, supplemented by purchased power, to meet the summer peak demands of its retail customers. Due to its increasing natural gas and purchased power usage, TEP hedges a portion of its total energy price exposure with forward priced contracts. Certain of these contracts are at a fixed price per megawatt-hour (MWh) and others are indexed to natural gas prices. TEP also purchases power in the daily and hourly markets to meet higher than anticipated demands, to cover generation outages, or when doing so is more economical than generating its own power.

TEP is a member of a regional reserve-sharing organization and has reliability and power-sharing relationships with other utilities. These relationships allow TEP to call upon other utilities during emergencies, such as facility outages and system disturbances, and reduce the amount of reserves TEP is required to carry.

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Peak Demand and Future Resources

Peak Demand

(in MW)	2017	2016	2015	2014	2013
Retail Customers	2,415	2,278	2,222	2,218	2,230

In 2017, TEP's generation and purchased resources were sufficient to meet total retail and long-term wholesale peak demand, while maintaining a reserve margin in compliance with reliability criteria set forth by the Western Electricity Coordinating Council, a regional council of North American Reliability Corporation (NERC).

Peak demand occurs during the summer months due to the cooling requirements of retail customers in TEP's service territory. Retail peak demand varies from year-to-year due to weather, energy conservation, DG, economic conditions, and other factors. Retail peak demand in 2017 increased 6% compared to 2016 due to unseasonably hot weather. Forecasted retail peak demand for 2018 is 2,270 MW compared with actual peak demand of 2,415 MW in 2017. TEP's 2018 estimated retail peak demand is based on weather patterns observed over a 10-year period and other factors, including estimates of customer usage. TEP believes that existing generation capacity and PPAs are sufficient to meet the expected demand and reserve margin requirements in 2018.

Future Resources

As of December 31, 2017, approximately 49% of TEP's generation capacity is coal-fired generation. TEP is executing strategies and evaluating additional steps to reduce its dependency on coal-fired generation while still meeting its peak load requirements and maintaining affordable Retail Rates. TEP's five-year capital expenditure forecast includes investments related to Reciprocating Internal Combustion Engines (RICE) at H. Wilson Sundt Generating Station (Sundt) and the planned purchase of Gila River Generating Station (Gila River) Unit 2. These anticipated investments will provide replacement capacity for the planned early retirements of coal-fired and other generation resources.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations of this Form 10-K for additional information regarding TEP's generation resources planned retirements and additions.

Fuel Supply

A summary of Fuel and Purchased Power resource information is provided below:

	Average Cost (cents per kWh)			Percentage of Total kWh Resources		
	2017	2016	2015	2017	2016	2015
Coal	2.41	2.30	2.44	54 %	62 %	60 %
Gas	3.06	2.84	3.35	23 %	25 %	19 %
Purchased Power, Non-Renewable	3.78	3.43	3.04	18 %	8 %	18 %
Purchased Power, Renewable	6.67	7.00	9.82	5 %	5 %	3 %
				100 %	100 %	100 %

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Coal

The coal used for electric generation is low-sulfur, bituminous or sub-bituminous coal from mines in Arizona and New Mexico. The table below provides information on the existing coal contracts that supply our generation stations. The average cost of coal per million metric British thermal unit (MMBtu), including transportation, was $2.29 in 2017, $2.21 in 2016, and $2.34 in 2015.

Station	Coal Supplier	2017 Coal Consumption (tons in 000s)	Contract Expiration	Average Sulfur Content	Coal Obtained From
Springerville	Peabody CoalSales	2,289	2020	1.0%	Lee Ranch Mine/El Segundo Mine
Four Corners	NTEC	285	2031	0.7%	Navajo Mine
San Juan (1)	San Juan Coal Co.	1,181	2022	0.8%	San Juan Mine
Navajo	Peabody CoalSales	441	2019	0.6%	Kayenta Mine

(1) Reflects the fuel consumption of San Juan Units 1 and 2. In December 2017, San Juan Unit 2 was removed from service.

Coal-Fired Generation Facilities Operated by TEP

The coal supplies for Springerville Units 1 and 2 are transported approximately 200 miles by railroad from northwestern New Mexico. TEP expects coal reserves to be sufficient to supply the estimated requirements for Springerville Units 1 and 2 for their remaining lives.

Coal-Fired Generation Facilities Operated by Others

TEP also participates in jointly-owned coal-fired generation facilities at Four Corners Generating Station (Four Corners), the Navajo Generating Station (Navajo), and San Juan. Four Corners, which is operated by Arizona Public Service Company (APS), and San Juan, which is operated by Public Service Company of New Mexico (PNM), are mine-mouth generation facilities located adjacent to the coal reserves. Navajo, which is operated by Salt River Project Agricultural Improvement and Power District (SRP), obtains its coal supply from the nearby Kayenta coal mine and receives deliveries on a dedicated electric rail delivery system. TEP expects coal reserves available to these three jointly-owned generation facilities to be sufficient for the remaining lives of the stations.

Natural Gas Supply

TEP uses generation from its facilities fueled by natural gas, in addition to power from its coal-fired generation facilities and purchased power, to meet the summer peak demands of its retail customers and local reliability needs. The average cost of natural gas per MMBtu, including transportation, was $3.58 in 2017, $3.14 in 2016, and $3.49 in 2015.

TEP has long-term firm agreements with El Paso Natural Gas Company, LLC. (EPNG) for transportation from the Permian and San Juan Basins to Sundt under firm transportation agreements. TEP also purchases firm gas transportation for Gila River Unit 3 from EPNG and Transwestern Pipeline Co., and for the Luna Generating Station (Luna) from EPNG. TEP purchases natural gas from Southwest Gas Corporation under a retail tariff for North Loop Generating Station's (North Loop) 94 MW of internal combustion turbine generation and receives distribution service under a transportation agreement for DeMoss Petrie Generating Station's (DeMoss Petrie) 75 MW of internal combustion turbine generation.

Transmission and Distribution

TEP's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. TEP's transmission system, together with contractual rights on other transmission systems, enables TEP to integrate and access generation resources to meet its customer load requirements. TEP's transmission and distribution systems included approximately 2,175 miles of transmission lines and 7,642 miles of distribution lines as of December 31, 2017.

Rates and Regulations

The ACC and the FERC each regulate portions of utility accounting practices and rates of TEP. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, transactions with affiliated parties, and other utility matters. The ACC also enacts other regulations and policies that can affect business decisions and accounting practices. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

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See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations and Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information that relates to rates and regulations that affect TEP including key provisions of its 2017 Rate Order.

2017 Rate Order

In February 2017, the ACC issued a rate order in the rate case filed by TEP in November 2015, which was based on a test year ended June 30, 2015 (2017 Rate Order). The 2017 Rate Order authorizes an annual increase in non-fuel revenue requirements of $81.5 million. New billing rates were effective starting on February 27, 2017.

Purchased Power and Fuel Adjustment Clause

The Purchased Power and Fuel Adjustment Clause (PPFAC) allows TEP recovery of its fuel, transmission, purchased power, and other similar costs allowed by the ACC to serve its retail load. The PPFAC consists of a forward component and a true-up component. The forward component adjusts for any costs over or under base fuel collection rates expected over a 12-month period. The true-up component reconciles any over/under collected amounts from the preceding 12-month period and is calculated to credit or recover these amounts from customers in the subsequent year.

As of December 31, 2017, TEP had over-collected fuel and purchased power costs by $9 million.

Renewable Energy Standard and Tariff

The ACC's RES requires Arizona utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025, with DG accounting for 30% of the annual renewable energy requirement. Arizona utilities must file an annual RES implementation plan for review and approval by the ACC. The approved costs of carrying out this plan are recovered from retail customers through the RES surcharge. The associated lost revenues attributable to meeting DG targets will be partially recovered through the Lost Fixed Cost Recovery Mechanism (LFCR).

In 2017, the percentage of retail kilowatt-hour (kWh) sales from renewable energy was 13% of which approximately 10% was attributable to RES exceeding the 2017 requirement of 7%. The 2018 RES requirement is 8% of retail kWh sales. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain DG Renewable Energy Credits (REC), which are used to demonstrate compliance with the DG requirement, the ACC approved a waiver of the 2017 and 2018 residential distributed renewable energy requirement.

Energy Efficiency Standards

Under the Energy Efficiency Standards (EE Standards), the ACC requires electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. As of December 31, 2017, TEP's cumulative annual energy savings was approximately 14%.

Distributed Generation

In 2016, the ACC held proceedings under the Value and Cost of Distributed Generation (Value of DG) docket to examine the ACC's net metering rules and determine the value that utilities should pay DG customers who deliver electricity from rooftop solar systems back to the grid. Prior to this proceeding, the ACC's net metering rules allowed DG customers who overproduced electricity to carry-over or "bank" excess electricity at a value equal to the full retail rate per kWh. Banked kWh could then be used by the customer to offset future energy usage that could not be met by their DG system.

In December 2016, the ACC approved an order that will begin to reform net metering in Arizona. The order adopts a number of net metering changes and policies, including:

- placing DG customers in a separate rate class;
-

- grandfathering current DG customers under net metering rules and rate design for 20 years from interconnection application;
- eliminating the banking of excess kWh for non-grandfathered DG customers; and
- compensating non-grandfathered customers for their exported kWh based on the DG export rate in effect at the time of interconnection.

The initial compensation for DG exports will be based on a five-year historical average cost per kWh of TEP’s portfolio of owned and contracted utility-scale solar projects and will be established in a second phase of TEP's rate case (Phase 2). The DG

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export rate will be updated each year and customers adopting solar will be compensated for 10 years at the rate in effect at the time they file an application for interconnection. An avoided cost methodology will also be developed for potential use in TEP's next rate case. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations of this Form 10-K for additional information that relates to Phase 2.

FERC Compliance

In 2016, the FERC issued orders relating to certain late-filed Transmission Service Agreements (TSA), which resulted in TEP recording a liability and paying time-value refunds to the counterparties under these TSAs (FERC Refund Orders). In May 2017, the FERC informed TEP that the related investigation was closed. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to the FERC Refund Orders.

ENVIRONMENTAL MATTERS

The Environmental Protection Agency (EPA) regulates the amount of sulfur dioxide (SO_2), nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury, and other by-products produced by generation facilities. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its generation facilities. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. TEP expects the recovery of the cost of environmental compliance through Retail Rates.

National Ambient Air Quality Standards

In October 2015, the EPA released the final rule for the 8-hour U.S. National Ambient Air Quality Standards (NAAQS) for ozone (O_3). The EPA lowered the standard from 75 parts per billion (ppb) to 70 ppb. If Pima County does not meet the standard, the county will be designated as a "non-attainment" area and will need to develop a plan to bring the air-shed into compliance. A "non-attainment" designation may slow economic growth in the region and impact our ability to site new local generation. Arizona's recommendation of area designations (attainment, non-attainment, or unclassified) was submitted in September 2016, and Pima County's was recommended as an attainment area.

In November 2017, the EPA published a final rule in the Federal Register establishing the initial Air Quality designations, for the 2015 Ozone Standard. The majority of Arizona counties were designated as "attainment" or "unclassified" except for Pima and Maricopa counties for which a designation will be addressed in a separate, future action.

Effluent Limitation Guidelines

In 2015, as part of the Clean Water Act, the EPA published the final Effluent Limitation Guidelines (ELG) setting standards and limitations for steam electric generation facility discharges. The ELG rule establishes discharge limits for fly ash and mercury-contaminated wastewater at those facilities that require a National Pollution Discharge Elimination System (NPDES) with an effective date between November 2018 and November 2023. With the exception of Four Corners, none of the other TEP owned facilities require an NPDES permit and therefore are not affected. With regard to Four Corners, until a draft NPDES permit is proposed during the 2018-2023 time-frame, TEP cannot predict what will be required to control these discharges to be in compliance with the finalized effluent limitations at that facility. TEP does not anticipate a significant financial impact from these requirements.

In 2017, the EPA announced its decision to reconsider the ELG. The EPA also filed and was granted a motion requesting the U.S. Court of Appeals for the Fifth Circuit to hold the litigation challenging the Rule in abeyance while the Agency reconsiders the ELG, after which it will inform the Court of any portions of the ELG for which it seeks a remand so that it can conduct further rulemaking. As a result, the U.S. Court of Appeals for the Fifth Circuit approved a briefing schedule for the ELG that puts industry groups' challenges on hold indefinitely.

TEP believes it is in material compliance with applicable environmental laws and regulations. Refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources of this Form 10-K for additional information related to environmental laws and regulations as well as environmental compliance capital expenditures.

EMPLOYEES

As of December 31, 2017, TEP had 1,510 employees, of which approximately 671 are represented by the International Brotherhood of Electrical Workers Local No. 1116. The current collective bargaining agreements between the IBEW and TEP expire in December 2018.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Executive Officers, who are elected annually by TEP's Board of Directors, acting at the direction of the Board of Directors of UNS Energy, as of January 2, 2018, are as follows:

Name	Age	Position(s) Held	Executive Officer Since
David G. Hutchens [(1)]	51	President and Chief Executive Officer	2007
Frank P. Marino [(1)]	53	Vice President and Chief Financial Officer	2013
Erik B. Bakken	45	Vice President, Transmission and Distribution Planning and Environmental	2018
Kentton C. Grant	59	Vice President, Rates and Planning	2007
Susan M. Gray	45	Vice President, Energy Delivery	2015
Todd C. Hixon [(1)]	51	Vice President, General Counsel and Chief Compliance Officer	2011
Mark C. Mansfield	62	Vice President, Energy Resources	2012
Catherine E. Ries	58	Vice President, Customer and Human Resources	2007
Mary Jo Smith	60	Vice President, Public Policy and Rates	2015
Morgan C. Stoll	47	Vice President and Chief Information Officer	2016
Martha B. Pritz	56	Treasurer	2017
Herlinda H. Kennedy	56	Corporate Secretary	2006

(1) Member of the TEP Board of Directors. The directors of TEP are elected annually by TEP's sole shareholder, UNS Energy, acting at the direction of the Board of Directors of UNS Energy.

SEC REPORTS AVAILABLE ON TEP'S WEBSITE

TEP makes available its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practical after it electronically files or furnishes them to the Securities and Exchange Commission (SEC). These reports are available free of charge through TEP's website address at www.tep.com/about/investors/.

TEP is providing the address of TEP's website solely for the information of investors and does not intend the address to be an active link. The information contained on TEP's website is not a part of, or incorporated by reference into, any report or other filing filed with the SEC by TEP.

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ITEM 1A. RISK FACTORS

The business and financial results of TEP are subject to a number of risks and uncertainties, including those set forth below. These risks and uncertainties fall primarily into five major categories: revenues, regulatory, environmental, financial, and operational. Additional risks and uncertainties that are not currently known to TEP or that are not currently believed by TEP to be material may also harm TEP's business and financial results.

REVENUES

A significant decrease in the demand for electricity in TEP's service area would negatively impact retail sales and adversely affect results of operations, net income, and cash flows at TEP.

National and local economic conditions have a significant impact on customer growth and overall retail sales in TEP's service area. TEP anticipates an annual customer growth rate of 1% for the next five years.

Research and development activities are ongoing for new technologies that produce power and reduce power consumption. These technologies include renewable energy, customer-sited DG, appliances, equipment, battery storage and control systems. Continued development and use of these technologies and compliance with the ACC's EE Standards and RES continue to have a negative impact on TEP's use per customer and overall retail sales. TEP's use per customer declined by an average of 1% per year from 2013 through 2017.

The revenues, results of operations, and cash flows of TEP are seasonal and are subject to weather conditions and customer usage patterns, which are beyond the Company's control.

TEP typically earns the majority of its operating revenue and net income in the third quarter because retail customers increase their air conditioning usage during the summer. Conversely, TEP's first quarter net income is typically limited by relatively mild winter weather in its retail service territory. Cool summers or warm winters may reduce customer usage, negatively affecting operating revenues, cash flows, and net income by reducing sales.

TEP is dependent on a small number of customers for a significant portion of future revenues. A reduction in the electricity sales to these customers would negatively affect our results of operations, net income, and cash flows.

TEP's ten largest customers represented 10% of total revenues in 2017. TEP sells electricity to mines, military installations, and other large commercial and industrial customers. Retail sales volumes and revenues from these customers could decline as a result of, among other things: global, national, and local economic conditions; curtailments of customer operations due to unfavorable market conditions; military base reorganization or closure decisions by the federal government; the effects of energy efficiency and distributed generation; or the decision by customers to self-generate all or a portion of their energy needs. A reduction in retail kWh sales by any one of TEP's ten largest customers would negatively affect our results of operations, net income, and cash flows.

REGULATORY

TEP is subject to regulation by the ACC, which sets the Company's Retail Rates and oversees many aspects of its business in ways that could negatively affect the Company's results of operations, net income, and cash flows.

The ACC is a constitutionally created body composed of five elected commissioners. Commissioners are elected state-wide for staggered four-year terms and are limited to serving a total of two terms. As a result, the composition of the commission, and therefore its policies, are subject to change every two years.

TEP's Retail Rates consist of base rates and various rate adjustors that are intended to allow for timely recovery of certain costs between rate cases. The ACC is charged with setting Retail Rates at levels that are intended to allow TEP recovery of its cost of service and provide it with an opportunity to earn a reasonable rate of return. In setting TEP's Retail Rates, the ACC could disallow the recovery of costs, not provide for the timely recovery of costs or increase regulatory oversight. If customers or regulators have or develop a negative opinion of the Company's utility services or the electric utility industry in general, this could negatively affect TEP's regulatory outcomes. The decisions made by the ACC on such matters impact the net income and cash flows of TEP.

Changes in federal energy regulation may negatively affect the results of operations, net income, and cash flows of TEP.

TEP is subject to the impact of comprehensive and changing governmental regulation at the federal level that continues to change the structure of the electric utility industry and the ways in which this industry is regulated. TEP is subject to regulation

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by the FERC. The FERC has jurisdiction over rates for electric transmission in interstate commerce and rates for wholesale sales of electric power, including terms and prices of transmission services and sales of electricity at wholesale.

Owners and operators of bulk power systems, including TEP, are subject to mandatory transmission standards developed and enforced by NERC and subject to the oversight of the FERC. Compliance with modified or new transmission standards may subject TEP to higher operating costs and increased capital costs. Failure to comply with the mandatory transmission standards could subject TEP to sanctions, including substantial monetary penalties.

Changes in tax regulation may negatively affect the results of operations, net income, and cash flows of TEP.

The Company is subject to taxation by the various taxing authorities at the federal, state and local levels where it does business. Legislation or regulation could be enacted by any of these governmental authorities which could affect the Company's tax positions.

In December 2017, the Tax Cuts and Jobs Act (TCJA) was signed into law which enacted significant changes to the Internal Revenue Code including a reduction in the U.S. federal corporate income tax rate from 35% to 21% effective for tax years beginning after 2017. Subsequently, the ACC opened a docket requesting that all regulated utilities submit proposals to address passing any ongoing benefits of the TCJA through to customers. TEP cannot predict the timing or extent of the regulatory treatment related to the TCJA impacts but any decrease in rates paid by customers would have a negative impact on operating cash flows.

ENVIRONMENTAL

TEP is subject to numerous environmental laws and regulations that may increase its cost of operations or expose it to environmental-related litigation and liabilities. Many of these regulations could have a significant impact on TEP due to its reliance on coal for electric generation.

Numerous federal, state, and local environmental laws and regulations affect present and future operations. Those laws and regulations include rules regarding air emissions, water use, wastewater discharges, solid waste, hazardous waste, and management of coal combustion residuals.

These laws and regulations can contribute to higher capital, operating, and other costs, particularly with regard to enforcement efforts focused on existing generation facilities and compliance standards related to new and existing generation facilities. These laws and regulations generally require TEP to obtain and comply with a wide variety of environmental licenses, permits, authorizations, and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. Failure to comply with applicable laws and regulations may result in litigation, the imposition of fines, penalties, and a requirement by regulatory authorities for costly equipment upgrades.

Existing environmental laws and regulations may be revised and new environmental laws and regulations may be adopted or become applicable to our facilities. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a negative effect on TEP's results of operations, particularly if those costs are not fully recoverable from TEP customers. TEP's obligation to comply with the EPA's Regional Haze Rule requirements as a participant or owner in the Springerville, San Juan, Four Corners, and Navajo, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of these generation facilities. Additionally, these regulations may jeopardize continued generation facility operations or the ability of individual participants to meet their obligations and willingness to continue their participation in these facilities potentially resulting in an increased operational cost for the remaining participants.

TEP also is contractually obligated to pay a portion of the environmental reclamation costs incurred at generation facilities in which it has a minority interest and is obligated to pay similar costs at the mines that supply these generation facilities. While TEP has recorded the portion of its costs that can be determined at this time, the total costs for final reclamation at these sites are unknown and could be substantial.

Federal regulations limiting greenhouse gas emissions require a shift in generation from coal to natural gas and renewable generation and could increase TEP's cost of operations.

In 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil-fueled generation facilities. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan requires CO_2 emission reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. In its current form, the CPP requires a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal-fired generation in Arizona and New Mexico within the 2022 to 2030 compliance time-frame. In 2017, the EPA issued a proposal to repeal the CPP and has not determined whether or not a replacement rule will be issued. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. TEP is unable to determine whether the current CPP will remain in effect or be modified or any final CPP rule will impact its facilities until all legal challenges have been resolved and the currently required state compliance plans are developed and approved by the EPA.

FINANCIAL

Early closure of TEP's coal-fired generation facilities could result in TEP recognizing regulatory impairments or increased cost of operations if recovery of TEP's remaining investments in such facilities and the costs associated with early closures are not permitted through rates charged to customers.

Some of TEP's coal-fired generation facilities will be closed before the end of their useful lives in response to economic conditions and/or recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If any of the coal-fired generation facilities from which TEP obtains power are closed prior to the end of their useful life, TEP may need to seek recovery of the remaining net book value (NBV) and could incur added expenses relating to accelerated depreciation and amortization, decommissioning, reclamation and cancellation of long-term coal contracts of such generation facilities. As of December 31, 2017, TEP's regulatory assets balance related to its planned early generation retirement costs was $84 million.

Volatility or disruptions in the financial markets, rising interest rates, or unanticipated financing needs, could: increase TEP's financing costs; limit access to the credit or bank markets; affect the Company's ability to comply with financial covenants in debt agreements; and increase TEP's pension funding obligations. Such outcomes may negatively affect liquidity and TEP's ability to carry out the Company's financial strategy.

We rely on access to the bank markets and capital markets as a significant source of liquidity and for capital requirements not satisfied by the cash flows from our operations. Market disruptions such as those experienced in 2008 and 2009 in the United States and abroad may increase our cost of borrowing or negatively affect our ability to access sources of liquidity needed to finance our operations and satisfy our obligations as they become due. These disruptions may include turmoil in the financial services industry, including substantial uncertainty surrounding particular lending institutions and counterparties we do business with, unprecedented volatility in the markets where our outstanding securities trade, and general economic downturns in our utility service territories. If we are unable to access credit at reasonable rates, or if our borrowing costs dramatically increase, our ability to finance our operations, meet our debt obligations, and execute our financial strategy could be negatively affected.

Increases in short-term interest rates would increase the cost of borrowing on TEP's tax-exempt variable rate debt obligations of $137 million as of December 31, 2017, and increase the cost of borrowings under its credit facility. In addition, changing market conditions could negatively affect the market value of assets held in our pension and other postretirement defined benefit plans and may increase the amount and accelerate the timing of required future funding contributions.

Generation facility closings or changes in power flows into TEP's service territory could require us to redeem or defease some or all of the tax-exempt bonds issued for the Company's benefit. This could result in increased financing costs.

TEP has financed a substantial portion of utility plant assets with the proceeds of pollution control revenue bonds and industrial development revenue bonds issued by governmental authorities. Interest on these bonds is, subject to certain exceptions, excluded from gross income for federal tax purposes. This tax-exempt status is based, in part, on continued use of the assets for pollution control purposes or the local furnishing of power within TEP’s two-county retail service area.

As of December 31, 2017, there were outstanding approximately $309 million aggregate principal amount of tax-exempt bonds that financed pollution control expenditures at TEP’s generation facilities. Should certain of TEP’s generation facilities be retired and dismantled prior to the stated maturity dates of the related tax-exempt bonds, it is possible that some or all of the bonds financing such pollution control expenditures would be subject to early redemption by TEP. Of the total amount outstanding, $37 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $272 million of the principal amount of the bonds has early redemption dates or final maturities ranging from 2019 to 2022.

In addition, as of December 31, 2017, there were outstanding approximately $307 million aggregate principal amount of tax-exempt bonds that financed local furnishing facilities. Depending on changes that may occur to the regional generation mix in the desert southwest, to the regional bulk transmission network, or to the demand for retail power in TEP’s local service area, it is possible that TEP would no longer qualify as a local furnisher of power within the meaning of the Internal Revenue Code. If TEP could no longer qualify as a local furnisher of power, all of TEP’s tax-exempt local furnishing bonds could be subject to mandatory early redemption by TEP or defeasance to the earliest possible redemption date, and TEP could be required to pay additional amounts if interest on such bonds were no longer tax-exempt. Of the total tax-exempt local furnishing bonds outstanding, $100 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $207 million of the principal amount of the bonds has early redemption dates ranging from 2020 to 2023.

OPERATIONAL

The operation of electric generation facilities and transmission and distribution systems involves risks and uncertainties that could result in reduced generation capability or unplanned outages that could negatively affect TEP's results of operations, net income, and cash flows.

The operation of electric generation facilities and transmission and distribution systems involves certain risks and uncertainties, including equipment breakdown or failures, fires, weather, and other hazards, interruption of fuel supply, and lower than expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failures or other complications, occur from time to time. They are an inherent risk of our business and can cause damage to our reputation. If TEP's generation facilities or transmission and distribution systems operate below expectations, TEP's operating results could be negatively affected or TEP's capital spending could be increased.

TEP receives power from certain generation facilities that are jointly-owned and operated by third parties. Therefore, TEP may not have the ability to affect the management or operations at such facilities which could negatively affect TEP's results of operations, net income, and cash flows.

Certain of the generation facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities. As a result of this reliance on other operators, TEP may not be able to ensure the proper management of the operations and maintenance of the generation facilities. Further, TEP may have no ability or a limited ability to make determinations on how best to manage the changing economic conditions or environmental requirements which may affect such facilities. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such facilities could negatively impact the business and operations of TEP.

TEP is subject to physical attacks which could have a negative impact on the Company's business and results of operations.

As operators of critical energy infrastructure, TEP is facing a heightened risk of physical attacks on the Company's electric systems. Our electric generation, transmission, and distribution assets and systems are geographically dispersed and are often in rural or unpopulated areas which makes it especially difficult to adequately detect, defend from, and respond to such attacks.

If, despite our security measures, a significant physical attack occurred, we could have our operations disrupted, property damaged, experience loss of revenues, response costs, and other financial loss; and be subject to increased regulation, litigation, and damage to our reputation, any of which could have a negative impact on TEP's business and results of operations.

TEP is subject to cyber-attacks which could have a negative impact on the Company's business and results of operations.

TEP is facing a heightened risk of cyber-attacks. The Company's information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes. TEP's operations technology systems have direct control over certain aspects of the electric system, and the Company's utility business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business.

If, despite TEP's security measures, a significant cyber or data breach occurred, the Company could have: (i) our operations disrupted, property damaged, and customer information stolen; (ii) experience loss of revenues, response costs, and other financial loss; and (iii) be subject to increased regulation, litigation, and damage to our reputation. Any of these could have a negative impact on TEP's business and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Transmission facilities owned by TEP and third parties are located in Arizona and New Mexico and transmit the output from TEP’s electric generation facilities at Four Corners, Navajo, San Juan, Springerville, Gila River, and Luna to the Tucson area. The transmission system is interconnected at various points in Arizona and New Mexico with other regional utilities. See Part I, Item 1. Business, Overview of Business of this Form 10-K for additional information regarding the transmission facilities.

TEP's generation facilities (except as noted below), administrative headquarters, warehouses and service centers are located on land owned by TEP. The distribution and transmission facilities owned by TEP are located:

- on property owned by TEP;
- under or over streets, alleys, highways, and other places in the public domain, as well as in national forests and state lands, under franchises, land easements, or other rights-of-way which generally are subject to termination;
- under or over private property as a result of land easements obtained primarily from the record holder of title; or
- over tribal lands under the grant of easement by the Secretary of the Interior or leased from Indian Nations.

Springerville is located on property held by TEP under a term patent with the State of Arizona. TEP, under separate sale and leaseback arrangements, leases a 32.2% undivided interest in the Springerville Common Facilities (which does not include land).

Four Corners and Navajo are located on properties held under land easements from the United States and under leases from the Navajo Nation. TEP, individually and in conjunction with PNM in connection with San Juan, has acquired land rights, land easements, and leases for the generation facilities, the transmission lines, and a water diversion facility located on land owned by the Navajo Nation. TEP has also acquired land easements for transmission facilities related to San Juan, Four Corners, and Navajo located on tribal lands of the Zuni, Navajo, and Tohono O’odham Nations. TEP, in conjunction with PNM and Samchully Power & Utilities 1 LLC, holds an undivided ownership interest in the property on which Luna is located. TEP and UNS Electric, Inc. (UNS Electric), an affiliate subsidiary of TEP, own a 75% and 25%, respectively, undivided interest in Gila River Unit 3. Gila River Unit 3 is situated on land owned by TEP and UNS Electric, who also own a 25% undivided ownership interest in the common facilities at Gila River as tenants in common. TEP and UNS Electric, together with the remaining 75% common facilities owners have a free and clear title of all common facilities.

TEP’s rights under these various land easements and leases may be subject to defects such as:

- possible conflicting grants or encumbrances due to the absence of, or inadequacies in, the recording laws or record systems of the Bureau of Indian Affairs (BIA) and the Indian Nations;
- possible inability of TEP to legally enforce its rights against adverse claims and the Indian Nations without Congressional consent; or
- failure or inability of the Indian tribes to protect TEP’s interests in the land easements and leases from disruption by the U.S. Congress, Secretary of the Interior, or other adverse claims.

These possible defects have not interfered, and are not expected to materially interfere, with TEP’s interest in and operation of its facilities.

Under separate ground lease agreements, TEP leased parcels of land for the following PV facilities:

- the Solar Zone located at the University of Arizona Technology Park in Pima County, Arizona; and
- the Bright Tucson Community Solar located in Pima County, Arizona.

In addition, TEP has a 30-year easement agreement related to a PV facility in Cochise County, Arizona. The easement is to facilitate the operations of a solar PV renewable energy generation system on behalf of the Department of the Army.

See Part I, Item 1. Business, Overview of Business of this Form 10-K for additional information regarding generation facilities.

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ITEM 3. LEGAL PROCEEDINGS

TEP is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company believes such normal and routine litigation will not have a material impact on its consolidated financial results. TEP is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties, and other costs in substantial amounts on TEP.

See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Market Information

TEP's common stock is wholly-owned by UNS Energy and is not listed for trading on any stock exchange.

Dividends

TEP declared and paid dividends to UNS Energy of $70 million in 2017 and $50 million in 2016 and 2015.

ITEM 6. SELECTED FINANCIAL DATA

The following table provides selected financial data for the years 2013 through 2017:

(in thousands)	2017	2016	2015	2014	2013
Income Statement Data					
Operating Revenues	$1,340,935	$1,234,995	$1,306,544	$1,269,901	$1,196,690
Net Income	176,668	124,438	127,794	102,338	101,342
Balance Sheet Data					
Total Utility Plant, Net	$3,768,702	$3,782,806	$3,558,229	$3,425,190	$2,944,455
Total Assets	4,590,249	4,449,989	4,249,478	4,119,830	3,482,860
Long-Term Debt, Net	1,354,423	1,453,072	1,451,720	1,361,828	1,213,367
Non-Current Capital Lease Obligations	28,519	39,267	55,324	69,438	131,370
Other Data					
Ratio of Earnings to Fixed Charges [1]	5.06	3.69	3.74	2.56	2.67

(1) For purposes of this computation, earnings are defined as pre-tax earnings from continuing operations before minority interest, or income/loss from equity method investments, plus interest expense and amortization of debt discount and expense related to indebtedness. Fixed charges are interest expense, including amortization of debt discount, interest on operating lease payments, and expense on indebtedness, including capital lease obligations.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

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

Management’s Discussion and Analysis explains the results of operations, the general financial condition, and the outlook for TEP. It includes the following:

- outlook and strategies;
- operating results in 2017 compared with 2016, and 2016 compared with 2015;
- factors affecting our results of operations and outlook;
- liquidity and capital resources including capital expenditures, contractual obligations, and environmental matters;
- critical accounting policies and estimates; and
- recent accounting pronouncements.

Management’s Discussion and Analysis includes financial information prepared in accordance with Generally Accepted Accounting Principles in the United States of America (GAAP) financial measures. It also includes non-GAAP financial measures which should be viewed as a supplement to, and not a substitute for, financial measures presented in accordance with GAAP. Non-GAAP financial measures as presented herein may not be comparable to similarly titled measures used by other companies.

Management’s Discussion and Analysis should be read in conjunction with Part 2, Item 6, Selected Financial Data and the Consolidated Financial Statements and Notes in Part II, Item 8 of this Form 10-K. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see Forward-Looking Information at the front of this report and Part I, Item 1A. Risk Factors for additional information.

References in this discussion and analysis to "we" and "our" are to TEP.

OUTLOOK AND STRATEGIES

TEP's financial prospects and outlook are affected by many factors including: (i) global, national, regional, and local economic conditions; (ii) volatility in the financial markets; (iii) environmental laws and regulations; and (iv) other regulatory factors. Our plans and strategies include the following:

- Achieving constructive outcomes in our regulatory proceedings that will provide us: (i) recovery of our full cost of service and an opportunity to earn an appropriate return on our rate base investments; (ii) updated rates that provide more accurate price signals and a more equitable allocation of costs to our customers; and (iii) the ability to continue providing safe and reliable service.
- Continuing to focus on our long-term resource diversification strategy, including shifting from coal to natural gas, renewables, and energy efficiency while providing rate stability for our customers, mitigating environmental impacts, complying with regulatory requirements, leveraging and improving our existing utility infrastructure, and maintaining financial strength. This long-term strategy includes a target of meeting 30% of our customers’ energy needs with non-carbon emitting resources by 2030.
- Focusing on our core utility business through operational excellence, promoting economic development in our service territory, investing in infrastructure to ensure reliable service, and maintaining a strong community presence.

Operational and Financial Highlights

For 2017, Management's Discussion and Analysis includes the following notable items:

- The ACC issued the 2017 Rate Order approving a non-fuel base rate increase of $81.5 million, a cost of equity component of 9.75%, and an equity ratio of approximately 50%. The new rates took effect on February 27, 2017.
- The Navajo Nation approved a land lease extension that allows Navajo to operate through December 2019 and decommissioning activities to begin thereafter. As a result of the planned early retirement, we transferred $52 million of the facility's NBV and other related costs to a regulatory asset.
- The FERC informed us that no further enforcement actions were necessary as the investigation related to the FERC Refund Orders had been closed. In addition, TEP and a counterparty, who had been a recipient of the time-value

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refunds in compliance with the FERC Refund Orders, entered into a settlement agreement which resulted in: (i) the counterparty paying TEP $8 million; and (ii) TEP dismissing a previously filed appeal.

- In conjunction with a generation modernization project at Sundt, we will discontinue operation of Sundt Units 1 and 2 by the end of 2020. As a result of the planned early retirements, we transferred $32 million of the facilities' NBV to a regulatory asset.
- We entered into a 20-year Tolling PPA with SRP to purchase and receive all 550 MW of capacity, power, and ancillary services from Gila River Unit 2. The Tolling PPA will allow us to continue to move toward its long-term goal of resource diversification. Our obligations under the agreement are contingent upon SRP's acquisition of Gila River Units 1 and 2, which is expected to be completed by March of 2018.
- We purchased an additional 17.8% undivided ownership interest in Springerville Common Facilities for $38 million bringing its total ownership interest to 67.8%.
- San Juan Unit 2 ceased operations in compliance with a State Implementation Plan (SIP) covering BART requirements for San Juan. TEP owns 50% of San Juan Unit 2 and applied excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations in years ended December 31, 2017, 2016, and 2015, presented on an after-tax basis.

2017 compared with 2016

TEP reported net income of $177 million in 2017 compared with $124 million in 2016. The increase of $53 million, or 43%, was primarily due to:

- $52 million in higher retail revenue primarily due to an increase in rates as approved in the 2017 Rate Order and an increase in usage due to favorable weather;
- $21 million in higher net income due to time-value FERC ordered refunds incurred in 2016 and the reversal of accrued refunds in 2017 related to late-filed TSAs. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to late-filed TSAs; and
- $6 million in higher wholesale revenue primarily due to favorable pricing on wholesale contracts in 2017.

The increase was partially offset by:

- $8 million in lower revenues related to the Springerville Unit 1 settlement in 2016. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to the settlement;
- $7 million in higher income tax expense primarily due to the enactment of the TCJA in 2017 as well as changes to our valuation allowance for deferred tax assets in 2016. See Note 12 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to impacts of the TCJA on our financial results;
- $6 million in higher depreciation and amortization expenses; and
- $4 million in higher operations and maintenance expense resulting primarily from an increase in maintenance expense due to planned generation outages in 2017 and employee wages and benefits.

2016 compared with 2015

TEP reported net income of $124 million in 2016 compared with $128 million in 2015. The decrease of $4 million, or 3%, was primarily due to:

- $13 million in lower net income associated with late-filed TSAs;
- $6 million in higher depreciation and amortization expenses primarily related to an increase in asset base; and
- $4 million in higher operations and maintenance expenses primarily related to an increase in outside services and employee wages and benefits.

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The decrease was partially offset by:

- $8 million in higher revenues related to the Springerville Unit 1 settlement in 2016;
- $6 million in lower income tax expense as a result of a reduction in the valuation allowance for deferred tax assets based on an increase in projected taxable income; and
- $4 million from higher LFCR revenues that partially offset lower retail sales.

Retail Revenues and Key Statistics

The following tables provide a reconciliation of Retail Revenues (GAAP) to Retail Margin Revenues (non-GAAP) and other key statistics impacting operating revenues:

	Years Ended December 31,		Increase (Decrease)	Year Ended December 31	Increase (Decrease)
($ in millions)	2017	2016	Percent	2015	Percent
Retail Revenues (GAAP)	$1,041	$ 990	5.2 %	$ 1,022	(3.1)%
Less recoveries from:					
Fuel and Purchased Power	275	305	(9.8)%	344	(11.3)%
DSM and RES Surcharge	53	54	(1.9)%	49	10.2 %
Retail Margin Revenues (non-GAAP) [(1)]	$713	$ 631	13.0 %	$ 629	0.3 %
Electric Sales (kWh in millions)					
Residential	3,786	3,724	1.7 %	3,724	— %
Commercial	2,192	2,139	2.5 %	2,124	0.7 %
Industrial	1,939	2,006	(3.3)%	2,063	(2.8)%
Mining	991	997	(0.6)%	1,109	(10.1)%
Public Authorities	18	30	(40.0)%	33	(9.1)%
Total Retail Sales	8,926	8,896	0.3 %	9,053	(1.7)%
Wholesale Sales, Long-Term	587	463	26.8 %	750	(38.3)%
Wholesale Sales, Short-Term	3,630	3,308	9.7 %	3,928	(15.8)%
Total Electric Sales	13,143	12,667	3.8 %	13,731	(7.7)%
Average Retail Rate (cents / kWh)	11.66	11.13	4.8 %	11.29	(1.4)%
Average Fuel and Purchased Power Rate	3.08	3.43	(10.2)%	3.80	(9.7)%
Average DSM and RES Surcharge Rate	0.59	0.61	(3.3)%	0.54	13.0 %
Total Average Retail Margin Rate	7.99	7.09	12.7 %	6.95	2.0 %

(1) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude revenues collected from retail customers that are directly offset by expenses recorded in other line items. TEP believes the change in Retail Margin Revenues between periods provides useful information for investors and analysts because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues from kWh sales, LFCR revenues, DSM performance bonus, and other revenues available to cover the non-fuel operating expenses of our core utility business.

Retail Revenues increased in 2017 compared with 2016 primarily due to higher Retail Margin Revenues related to an increase in rates as approved in the 2017 Rate Order and an increase in usage due to favorable weather in 2017. The increases were partially offset by a decrease in revenue from Fuel and Purchased Power recoveries as a result of lower

PPFAC rates.

Retail Revenues decreased in 2016 compared with 2015 primarily due to a decrease in revenue from Fuel and Purchased Power recoveries as a result of lower PPFAC rates partially offset by higher Retail Margin Revenues due to an increase in LFCR revenues.

See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information on the PPFAC mechanism and LFCR revenues.

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Wholesale Revenues

Wholesale Revenues increased by $57 million, or 49%, in 2017 compared with 2016 primarily due to: (i) time-value FERC ordered refunds incurred in 2016 and the reversal of accrued refunds in 2017, related to late-filed TSAs; (ii) favorable commodity pricing on the wholesale market; (iii) a new long-term wholesale contract that commenced in 2017; and (iv) an increase in short-term wholesale volumes.

Wholesale Revenues decreased by $50 million, or 30%, in 2016 compared with 2015 primarily due to: (i) time-value FERC ordered refunds incurred in 2016; (ii) decreased volumes and market prices of both short-term and long-term wholesale sales resulting from unfavorable market conditions; and (iii) termination of a firm contract at the end of May 2016.

Short-term wholesale revenues are primarily related to ACC jurisdictional assets and are returned to retail customers by crediting the revenues against fuel and purchased power costs eligible for recovery through the PPFAC.

Other Revenues

Other Revenues decreased by $3 million, or 2%, in 2017 compared with 2016 primarily due to a Springerville Unit 1 settlement agreement in 2016. The decrease was partially offset by an increase in reimbursed costs to TEP from SRP, the owner of Springerville Unit 4, related to planned generation outages of the facility in 2017. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to the Springerville Unit 1 settlement.

Other Revenues increased by $10 million, or 8%, in 2016 compared with 2015 primarily due to the Springerville Unit 1 settlement agreement in 2016. The increase was offset by a decrease in reimbursed costs to TEP from Tri-State Generation and Transmission Association, Inc. (Tri-State), the lessee of Springerville Unit 3, and SRP related to planned generation outages at Springerville Units 3 and 4 in 2015.

Operating Expenses

Fuel and Purchased Power Expense

Fuel and Purchased Power Expense, which includes PPFAC recovery treatment, increased by $5 million, or 1%, in 2017 compared with 2016 primarily due to an increase in Purchased Power volumes that replaced lower Coal-Fired Generation output, and an increase in average fuel cost per kWh (see table below). The increases were partially offset by reduced recovery of PPFAC costs as a result of changes in PPFAC rates. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information on the PPFAC mechanism.

Fuel and Purchased Power Expense, which includes PPFAC recovery treatment, decreased by $75 million, or 15%, in 2016 compared with 2015 primarily due to a decrease in: (i) Purchased Power, Non-Renewable volumes; (ii) Coal-Fired Generation output; and (iii) average cost fuel and purchased power per kWh (see table below). The decrease was partially offset by an increase in Gas-Fired Generation output.

TEP’s sources of energy are detailed in the following table:

	Years Ended December 31,		Increase (Decrease)		Year Ended December 31,	Increase (Decrease)	
(kWh in millions)	2017	2016	Percent		2015	Percent	
Sources of Energy							
Coal-Fired Generation	7,530	8,310	(9.4	)%	8,584	(3.2	)%
Gas-Fired Generation	3,237	3,283	(1.4	)%	2,723	20.6	%
Utility-Owned Renewable Generation	83	68	22.1	%	65	4.6	%
Total Generation	10,850	11,661	(7.0	)%	11,372	2.5	%
Purchased Power, Non-Renewable	2,471	1,126	119.4	%	2,627	(57.1	)%
Purchased Power, Renewable	646	666	(3.0	)%	452	47.3	%

Total Generation and Purchased Power	13,967	13,453	3.8 %	14,451	(6.9)%

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TEP's average fuel cost of generated power and the average cost of purchased power per kWh are detailed in the following table:

(cents per kWh)	Years Ended December 31, 2017	2016	Increase (Decrease) Percent	Year Ended December 31, 2015	Increase (Decrease) Percent
Average Fuel Cost of Generated Power					
Coal	2.41	2.30	4.8 %	2.44	(5.7)%
Natural Gas	3.06	2.84	7.7 %	3.35	(15.2)%
Average Cost of Purchased Power					
Purchased Power, Non-Renewable	3.78	3.43	10.2 %	3.04	12.8 %
Purchased Power, Renewable	6.67	7.00	(4.7)%	9.82	(28.7)%

Operations and Maintenance Expense

Operations and Maintenance Expense increased by $6 million, or 2%, in 2017 compared with 2016 primarily due to an increase in: (i) maintenance expense related to planned generation outages and an increase in employee wages and benefits. The increase was partially offset by a decrease in RES and DSM program expenses.

Operations and Maintenance Expense increased by $9 million, or 3%, in 2016 compared with 2015 primarily due to an increase in: (i) maintenance expense related to planned generation outages, outside services, and employee wages and benefits; and (ii) an increase in RES and DSM program expenses.

RES and DSM program expenses are fully recovered through the cost recovery mechanisms and have no impact on earnings.

Other Income (Deductions)

Other Income (Deductions) increased by $9 million in 2017 compared with 2016 primarily due to a settlement agreement in 2017 related to late-filed TSAs. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K.

There were no significant changes to Other Income (Deductions) in 2016 compared with 2015.

Income Tax Expense

Income Tax Expense increased by $41 million, or 70%, in 2017 compared with 2016 primarily due to the increase in earnings before tax, the enactment of the TCJA in December 2017, and a reduction in the valuation allowance for deferred tax assets in 2016. See Note 12 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to impacts of the TCJA on our financial results.

Income Tax Expense decreased by $12 million, or 17%, in 2016 compared with 2015 primarily due to the decrease in earnings before tax income and a reduction in the valuation allowance for deferred tax assets based on an increase in projected taxable income.

FACTORS AFFECTING RESULTS OF OPERATIONS

Regulatory Matters

TEP is subject to comprehensive regulation. The discussion below contains material developments to those matters.

2017 Rate Order

In February 2017, the ACC issued a rate order in the rate case filed by TEP in November 2015. TEP's rate filing was based on a test year ended June 30, 2015. The 2017 Rate Order approved new rates that went into effect on February 27, 2017.

The provisions of the 2017 Rate Order include, but are not limited to:

- a non-fuel base rate increase of $81.5 million which includes $15 million of operating costs related to the 50.5% undivided interest in Springerville Unit 1 purchased by TEP in September 2016;

- a 7.04% return on original cost rate base of approximately $2 billion;
- a cost of equity component of 9.75% and a cost of debt component of 4.32%;

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- a capital structure for rate making purposes of approximately 50% common equity and 50% long-term debt;
- adoption of TEP's proposed depreciation and amortization rates, which include a reduction in the depreciable life for San Juan Unit 1; and
- approval of a request to apply excess depreciation reserves against the unrecovered NBV of San Juan Unit 2 and the coal handling facilities at Sundt due to early retirement.

The ACC deferred matters related to net metering and rate design for new DG customers to Phase 2, which is currently expected to be completed in the first half of 2018. TEP cannot predict the outcome of these proceedings. See Phase 2 Proceedings below.

Distributed Generation

In 2016, the ACC held proceedings under the Value and Cost of DG docket to examine the ACC's net metering rules and determine the value that utilities should pay DG customers who deliver electricity from rooftop solar systems back to the grid. Prior to these proceedings, the ACC's net metering rules allowed DG customers who over-produced electricity to carry-over or "bank" excess electricity at a value equal to the full retail rate per kWh. Banked kWh could then be used by customers to offset future energy usage that could not be met by their DG system.

In December 2016, the ACC approved an order that will begin to reform net metering in Arizona. The order adopts a number of net metering changes and policies, including:

- placing DG customers in a separate rate class;
- grandfathering current DG customers under net metering rules and rate design for 20 years from interconnection application;
- eliminating the banking of excess kWh for non-grandfathered DG customers;
- compensating non-grandfathered customers for their exported kWh for 10 years at the DG export rate in effect at the time of interconnection;
- updating the DG export rate annually; and
- developing an avoided cost methodology for calculating the DG export rate in the utility's next rate case.

The initial DG export rate will be established in Phase 2. See Phase 2 Proceedings below.

Phase 2 Proceedings

In March 2017, TEP filed direct testimony in its Phase 2 proceedings addressing rate design for new DG customers. The proposals include options for either a Time-Of-Use (TOU) energy rate with a basic customer service charge plus a monthly grid access fee based on the size of the DG system; or a TOU energy rate with a basic customer service charge plus a charge based on the highest hourly demand during the month. TEP also proposed that: (i) new DG customers receive a bill credit for excess energy exported to the grid at an initial rate of 9.7 cents/kWh; (ii) the DG export rate be updated based on a five-year rolling average cost of the company's owned and contracted utility scale renewable energy projects; (iii) customers who submit DG applications prior to the ACC's Phase 2 decision be grandfathered under current net metering rules and rate design for a period of 20 years from the date of interconnection of their DG system; and (iv) customers who install DG after the ACC's Phase 2 decision be compensated for 10 years at the rate in effect at the time they file an application for interconnection. A final ACC decision is currently expected in the first half of 2018. TEP cannot predict the outcome of these proceedings.

Federal Income Tax Legislation

On December 22, 2017, the President of the United States of America signed into law the TCJA, which enacted significant changes to the Internal Revenue Code including a reduction in the U.S. federal corporate income tax rate from 35% to 21% effective for tax years beginning after 2017. TEP has revalued its deferred tax assets and liabilities at the new federal corporate income tax rate as of the date of enactment of the TCJA. We are still in the process of analyzing the ongoing impacts of the TCJA on our operations. See Note 12 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding current year impacts of the TCJA.

In December 2017, the ACC opened a docket related to the TCJA. On February 6, 2018, the ACC ordered utilities to file within 60 days either: (i) an application for a tax adjustor mechanism; (ii) an intent to file a rate case within 90 days; or (iii) any other

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application to address the effects of the TCJA. TEP expects to file a tax adjustor proposal with the ACC prior to the deadline addressing the method it will use to pass through TCJA benefits to its customers. TEP will defer the ACC jurisdictional tax benefits as a regulatory liability until the proceedings are finalized.

TEP offsets its net operating loss carryforwards against taxable income and does not expect to make federal income tax payments until 2020. Any interim return of benefits to customers related to the TCJA would have a negative impact on TEP's operating cash flows.

TEP cannot predict the outcome of these proceedings or the impact on the Company's financial position or results of operations.

Generation Resources

As of December 31, 2017, approximately 49% of TEP's peak generation capacity was sourced from coal-fired generation resources. As part of TEP's long-term diversification strategy, TEP is evaluating additional steps to reduce its reliance on coal-fired generation.

Integrated Resource Plan

TEP’s long-term strategy to shift to a more diverse, sustainable energy portfolio is described in its Integrated Resource Plan (IRP) filed in April 2017 with the ACC. TEP's 2017 IRP discusses continuing efforts to diversify its generation portfolio including expanding renewable energy and natural gas-fired resources while reducing reliance on coal-fired generating resources. TEP's existing coal-fired generation fleet faces a number of uncertainties impacting the viability of continued operations including competition from other resources, fuel supply and land lease contract extensions, environmental regulations, and, for jointly owned facilities, the willingness of other owners to continue their participation. Given this uncertainty, TEP may consider options that include changes in generation facility ownership shares, unit shutdowns, or the sale of generation assets to third-parties. TEP will seek regulatory recovery for amounts that would not otherwise be recovered, if any, as a result of these actions.

See Part I, Item 1. Business, Overview of Business and Liquidity and Capital Resources, Environmental Matters of this Form 10-K for additional information regarding generation facility operations.

Arizona Energy Modernization Plan

The ACC will be considering adoption of a new energy policy for Arizona that would establish a goal of clean energy sources making up at least 80% of the state’s electricity generation portfolio by 2050. The adoption of a new policy is subject to a rulemaking proceeding at the ACC. TEP cannot predict the outcome of this proposal or the impact on the Company's financial position or results of operations.

Navajo Generating Station

In 2017, the Navajo Nation approved a land lease extension which allows TEP and the co-owners of Navajo to continue operations through December 2019 and begin decommissioning activities thereafter. We are currently recovering Navajo capital and operating costs in base rates using a useful life through 2030. As a result of the planned early retirement of Navajo, $52 million of the facility's NBV, and other related costs, were reclassified from Utility Plant, Net to Regulatory Assets on the Consolidated Balance Sheets as of December 31, 2017. We plan to seek recovery of all unrecovered costs in our next ACC rate case. See Note 2 for additional information related to the planned early retirement of Navajo.

Sundt Generating Station

In 2017, TEP submitted an Application to the PDEQ related to a generation modernization project at Sundt. In conjunction with the project, TEP will discontinue operation of Sundt Units 1 and 2 by the end of 2020. As a result of the planned early retirement, $31 million of the facilities' NBV was reclassified from Utility Plant, Net to Regulatory Assets on the Consolidated Balance Sheets as of December 31, 2017. We plan to seek recovery of all unrecovered costs in our next ACC rate case. See Note 2 for additional information regarding the 2017 Rate Order.

Under the project outlined in the Application, TEP will invest in 190 MW of RICE generators scheduled for commercial operation between June 2019 through March 2020. The RICE generators balance the variability of intermittent renewable energy resources and will replace 162 MW of nominal net generating capacity from Sundt Units 1 and 2, which are less efficient and lack the quick start, fast ramp capabilities of RICE generators. See Note 2 for additional information related to the planned early retirement of Sundt Units 1 and 2.

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Gila River Generating Station

In 2017, TEP entered into a 20-year Tolling PPA with SRP to purchase and receive all 550 MW of capacity, power, and ancillary services from Gila River Unit 2 (Tolling PPA). TEP’s obligations under the Tolling PPA are contingent upon SRP's acquisition of Gila River Units 1 and 2. In October 2017, SRP entered into a separate agreement with a third party to acquire Gila River Units 1 and 2 that is expected to be completed by March 2018 (Gila Acquisition). If the Gila Acquisition is terminated for any reason, either TEP or SRP may terminate the Tolling PPA without cost or penalty by providing written notice to the other party. The Tolling PPA provides TEP with an option to purchase Gila River Unit 2 during a three-year period beginning on the date the Gila Acquisition is completed. TEP's purchase option price for Gila River Unit 2 is expected to be $165 million, but is dependent upon SRP's final purchase price. The Tolling PPA will replace coal-fired generation scheduled for early retirement and provide near term opportunities for sales into the wholesale market.

Long-Term Wholesale Sales

Navopache Electric Cooperative

In January 2017, a new long-term contract between TEP and NEC became effective. The contract expires at the end of 2041. TEP served 80% of NEC’s load requirements in 2017 and expects to serve 100% beginning in 2018. In 2017, revenues from the NEC contract accounted for 8% of total Wholesale Revenues on the Consolidated Statements of Income.

Interest Rates

See Part II, Item 7A. Quantitative and Qualitative Disclosures about Market Risk of this Form 10-K for information regarding interest rate risks and its impact on earnings.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

Cash flows may vary during the year with cash flows from operations typically the lowest in the first quarter of the year and highest in the third quarter due to TEP’s summer peaking load. We will use our revolving credit facility as needed to assist in funding business activities. We believe that we have sufficient liquidity under our revolving credit facility to meet short-term working capital needs and to provide credit enhancement as necessary under energy procurement and hedging agreements. The availability and terms under which TEP has access to external financing depends on a variety of factors, including its credit ratings and conditions in the overall capital markets.

Available Liquidity

(in millions)	December 31, 2017
Cash and Cash Equivalents	$ 38
Amount Available under Revolving Credit Facility (1)	215
Total Liquidity	$ 253

(1) TEP's revolving credit facility provides for $250 million of revolving credit commitments and a Letter of Credit (LOC) sublimit of $50 million. TEP requested and was granted two one-year extensions. The new maturity date is October 2022.

Future Liquidity Requirements

We expect to meet all of our financial obligations and other anticipated cash outflows for the foreseeable future. These obligations and anticipated cash outflows include, but are not limited to dividend payments, debt maturities, and obligations as detailed in the Contractual Obligations and forecasted Capital Expenditures tables below.

See Part III, Item 7A. Quantitative and Qualitative Disclosures about Market Risk for additional information regarding TEP's market risks and Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding TEP's financing arrangements.

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Summary of Cash Flows

Effective December 31, 2017, TEP early adopted accounting guidance that requires entities to show the changes in the total of cash, cash equivalents, and restricted cash or restricted cash equivalents on the cash flow statement. The new accounting guidance is applied retrospectively affecting all periods presented. The table below incorporates the new accounting guidance and presents net cash provided by (used for) operating, investing and financing activities and its effect on cash, cash equivalents, and restricted cash:

	Years Ended		Increase (Decrease)	Year Ended	Increase (Decrease)
(in millions)	2017	2016	Percent	2015	Percent
Operating Activities	$448	$425	5.4 %	$365	16.4 %
Investing Activities	(392)	(373)	5.1 %	(501)	(25.5)%
Financing Activities	(50)	(69)	(27.5)%	120	*
Net Increase (Decrease)	6	(17)	*	(16)	6.3 %
Beginning of Period	43	60	(28.3)%	76	(21.1)%
End of Period [(1)]	$49	$43	14.0 %	$60	(28.3)%

* Not meaningful

(1) Calculated on rounded data and may not tie to amounts on the Consolidated Statements of Cash Flows.

Operating Activities

2017 compared with 2016

In 2017, net cash flows provided by operating activities increased by $23 million compared with 2016 primarily due to: (i) higher net income related to an increase in rates as approved in the 2017 Rate Order and an increase in residential usage due to favorable weather; and (ii) $8 million in cash proceeds received in January 2017 from a settlement agreement.

The increase was partially offset by: (i) an ACC approved PPFAC credit that began returning a temporary over-collected PPFAC balance to customers in February 2017; (ii) $12.5 million received in September 2016 related to a settlement for operating costs of Springerville Unit 1 not occurring in 2017; and (iii) changes in working capital related to the timing of billing collections and payments.

See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K, 2017 Rate Order and Note 7, FERC Matters and Claims Related to Springerville Generating Station Unit 1 for additional information.

2016 compared with 2015

In 2016, net cash flows provided by operating activities increased by $60 million compared with 2015 primarily due to a: (i) over-collected fuel and purchased power costs under the PPFAC mechanism; (ii) decrease in cash paid for pension and other postretirement benefits funding; (iii) $12.5 million increase in cash proceeds related to the settlement of operating costs related to Springerville Unit 1 incurred on behalf of the Third-Party Owners; and (iv) change in working capital related to the timing of billing collections and payments.

The increase was partially offset by an increase of $11 million in cash paid for incentive compensation in 2016 not occurring in 2015. As a result of the Fortis acquisition in 2014, payments scheduled to be paid in the first quarter of 2015 under the annual incentive compensation plan were accelerated and paid in the third quarter of 2014.

Investing Activities

2017 compared with 2016

In 2017, net cash flows used for investing activities increased by $19 million compared with 2016 primarily due to an increase in cash paid for capital expenditures and for the purchase of RECs.

See Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information on Springerville capital lease purchases.

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2016 compared with 2015

In 2016, net cash flows used for investing activities decreased by $127 million compared with 2015 primarily due to a decrease in cash paid for capital expenditures including generation assets and construction costs in 2015 for a new 500kV transmission line not occurring in 2016.

The decrease was partially offset by: (i) cash proceeds received in 2015 from the sale of an undivided ownership interest in Springerville Coal Handling Facilities not occurring in 2016; and (ii) an increase in cash paid in 2016 for the purchase of RECs.

Financing Activities

2017 compared with 2016

In 2017, net cash flows used for financing activities decreased by $19 million compared with 2016 primarily due to an increase in proceeds borrowed, net of repayments, under our revolving credit facility. The decrease was partially offset by an increase in dividends paid to UNS Energy.

2016 compared with 2015

In 2016, net cash flows provided by financing activities decreased by $189 million compared with 2015 primarily due to a decrease in: (i) cash proceeds received from the issuance of long-term debt and term loans, net of repayments made; and (ii) equity contributions from UNS Energy. Proceeds received in 2015 were used to purchase or retire certain tax-exempt long-term debt. The decrease was partially offset by a decrease in cash paid in 2016, net of proceeds borrowed, under our revolving credit facilities.

See Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K, Debt Issuance and Redemption for additional information.

Sources of Liquidity

Short-Term Investments

Our short-term investment policy governs the investment of excess cash balances. We periodically review and update this policy in response to market conditions. As of December 31, 2017, TEP's short-term investments included highly-rated and liquid money market funds.

Access to Revolving Credit Facility

We have access to working capital through a revolving credit agreement with lenders. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. As of December 31, 2017, $215 million was available under the revolving credit commitments and LOC facility. As of February 14, 2018, $232 million was available under the revolving credit commitments and LOC facility.

For details of TEP's credit facility see Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

Debt Financing

We use debt financing to meet a portion of our capital needs and lower our overall cost of capital. We are exposed to adverse changes in interest rates to the extent that we rely on variable rate financing. Our cost of capital is also affected by our credit ratings.

In 2016, the ACC issued an order granting TEP financing authority. The order extends and expands the previous financing authority by: (i) extending authority from December 2016 to December 2020; (ii) increasing the outstanding long-term debt limitation from $1.7 billion to $2.2 billion; (iii) allowing parent equity contributions of up to $400 million; and (iv) continuing the interest rate hedging authority.

We anticipate raising additional capital in the second half of 2018 to: (i) refinance tax-exempt local furnishing bonds that are subject to mandatory tender for purchase in November 2018; (ii) refinance callable tax-exempt pollution control bonds backed by an LOC which expires in February 2019; and (iii) ensure adequate revolving credit capacity. TEP has, from time to time,

refinanced or repurchased portions of its outstanding debt before scheduled maturity. Depending on market conditions, TEP may refinance other debt issuances or make additional debt repurchases in the future.

In January 2015, TEP purchased $130 million aggregate principal amount of unsecured tax-exempt Industrial Development Revenue Bonds issued in June 2008 by the Industrial Development Authority of Pima County, Arizona for the benefit of TEP and the bonds were not remarketed. The multi-modal bonds had an original maturity date of September 2029. In September 2017 the bonds were retired.

Credit Ratings

Credit ratings affect our access to capital markets and supplemental bank financing. In April 2017, S&P Global Ratings upgraded TEP’s credit rating on senior unsecured debt to A- from BBB+. As of December 31, 2017, the credit rating remained unchanged. As of December 31, 2017, Moody’s Investors Service credit ratings for TEP’s senior unsecured debt was A3.

TEP's credit ratings are dependent on a number of factors, both quantitative and qualitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell, or hold TEP securities. Each rating should be evaluated independently of any other ratings.

Certain of TEP's debt agreements contain pricing based on TEP’s credit ratings. A change in TEP’s credit ratings can cause an increase or decrease in the amount of interest TEP pays on its borrowings, and the amount of fees it pays for its LOCs and unused commitments.

Debt Covenants

Under certain agreements, should TEP fail to maintain compliance with covenants, lenders could accelerate the maturity of all amounts outstanding. As of December 31, 2017, TEP was in compliance with these covenants.

We do not have any provisions in any of our debt or lease agreements that would cause an event of default or cause amounts to become due and payable in the event of a credit rating downgrade.

Contribution from Parent

TEP received no equity contributions in 2017 and 2016. UNS Energy made an equity contribution to TEP of $180 million in 2015. The contributions were used to repay revolving credit loans, redeem bonds, and provide additional liquidity to TEP.

Dividends Paid to Parent

TEP declared and paid $70 million in dividends to UNS Energy in 2017 and $50 million in 2016 and 2015.

Master Trading Agreements

TEP conducts its wholesale marketing and risk management activities under certain master agreements. Under these agreements, TEP may be required to post credit enhancements in the form of cash or an LOC due to exposures exceeding unsecured credit limits provided to TEP, changes in contract values, changes in TEP’s credit ratings, or material changes in TEP’s creditworthiness. As of December 31, 2017, TEP had posted no cash or LOCs as credit enhancements with its counterparties.

Capital Expenditures

TEP's routine capital expenditures include funds used for customer growth, system reinforcement, replacements and betterments, and costs to comply with environmental rules and regulations. In 2017, total capital expenditures of $346 million, included the purchase of an additional 17.8% undivided interest in Springerville Common Facilities. In 2016, total capital expenditures of $335 million, included the purchase of the remaining ownership interest in Springerville Unit 1. In 2015, total capital expenditures of $500 million, included the purchase of an undivided ownership interest in Springerville Unit 1 and the remaining ownership interest in the Springerville Coal Handling Facilities.

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We expect capital requirements to increase in 2018 and 2019 to reflect our investment in generating assets and an enhanced metering and distribution network. Capital requirements are expected to level off from 2020 through 2022 as we focus on sustaining operations and renewable energy. Our forecasted capital expenditures presented below for years ended December 31 exclude amounts for AFUDC and other non-cash items:

(in millions)	2018	2019	2020	2021	2022
Generation Facilities:					
Renewable Energy	$11	$18	$5	$108	$—
Other Generation Facilities	163	284	79	75	51
Total Generation Facilities	174	302	84	183	51
Transmission and Distribution	194	184	202	167	152
General and Other [1]	99	88	67	96	65
Total Capital Expenditures	$467	$574	$353	$446	$268

[1] Includes cost for information technology, fleet, facilities, and communication equipment.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to fluctuations in business and market conditions, construction schedules, possible early plant closures, changes in generation resources, environmental requirements, state or federal regulations, and other factors. We expect to pay for forecasted capital expenditures with internally generated funds and external financings, which may include issuances of long-term debt or other borrowings.

Contractual Obligations

The following table summarizes our material contractual obligations as of December 31, 2017:

		Payments Due by Period			
(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-Term Debt					
Principal [1]	$1,466	$100	$ 117	$ 250	$999
Interest [2]	650	60	115	95	380
Capital Lease Obligations [3]	42	12	30	—	—
Operating Leases [4]	8	1	2	2	3
Land Easements and Rights-of-Way [5]	89	1	3	3	82
Purchase Obligations:					
Fuel, Including Transportation [6]	549	82	156	67	244
Purchased Power	29	29	—	—	—
Transmission	59	19	27	5	8
Renewable Purchase Power Agreements [7]	985	64	127	126	668
RES Performance-Based Incentives [8]	83	8	15	14	46
Acquisition of Springerville Common Facilities [9]	68	—	—	68	—
Other Long-Term Liabilities: [10] [11]					
Restricted and Performance-Based Stock Units	8	2	6	—	—
Pension and Other Postretirement Benefits [12]	78	17	12	13	36
Total Contractual Obligations	$4,114	$395	$ 610	$ 643	$2,466

[1] $37 million of TEP’s variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in February 2019. Although the variable rate bond matures in 2032, the above table reflects a redemption or repurchase of such bond in February 2019 as though the LOC terminates without

replacement upon expiration of the 2010 Reimbursement Agreement. TEP's 2013 tax-exempt variable rate Industrial Development Revenue Bonds (IDRB), which have an aggregate principal amount of $100 million and mature in 2032, are subject to mandatory tender for purchase in November 2018. The bonds

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were reclassified to Current Maturities of Long-Term Debt on the Consolidated Balance Sheets in 2017. Total long-term debt is not reduced by $10 million of related unamortized debt issuance costs or $2 million of unamortized original issue discount.

(2) Excludes interest on revolving credit facilities and includes interest on TEP's 2013 tax-exempt IDRBs through the end of the current five-year term.

(3) Effective with commercial operation of Springerville Unit 3 in July 2006 and Unit 4 in December 2009, Tri-State and SRP began reimbursing TEP for various operating costs related to the common facilities on an ongoing basis. The common facilities include assets leased by TEP at Springerville. TEP was reimbursed for $9 million of operating costs in 2017 by SRP and Tri-State and expects to be reimbursed $8 million of operating costs in 2018. Capital Lease Obligations do not reflect any reduction associated with this reimbursement. Our capital lease obligation balances decline over time as scheduled capital lease payments are made by TEP.

(4) Primarily represents leases for land, rail cars, and office facilities with varying terms, provisions, and expiration dates through 2036.

(5) Have varying terms and provisions and reflect expiration dates through 2054. In November 2017, the Navajo Nation approved an extension for the use of their land that commences in December 2019 and ends in December 2054. The Navajo Nation has until December 2018 to select one of five different rental payments options provided for in the extension. The table above includes TEP's 7.5% ownership share of the option which, in management's opinion, is most probable to occur. The total obligation estimated under this option is $8 million commencing in 2019 through 2053. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding Land Easements and Rights-of-Way.

(6) Excludes TEP’s liability for final mine reclamation costs related to coal mines that supply generation facilities in which TEP has an ownership interest but does not operate as the timing of payments has not been determined. In January 2018, TEP entered into a transportation agreement with EPNG to extend the expiration date of the existing agreement from April 2018 to April 2023. Estimated future payments not included in the table above are: $4 million in 2018; $5 million in 2019 through 2022; and $1 million through the end of the contract. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding TEP’s share of reclamation costs.

(7) TEP enters into long-term renewable PPAs which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding PPAs.

(8) TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance-Based Incentives (PBI) and are paid in contractually agreed upon intervals (usually quarterly) based on metered renewable energy production. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding PBIs.

(9) In December 2017, TEP purchased one of the Springerville Common Facilities Leases that had an initial term ending December 2017. The remaining two leases have an initial term ending January 2021, subject to optional renewal periods of two or more years. TEP may renew the two leases or exercise its remaining fixed-price purchase options. See Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding Springerville Common Facilities Leases.

(10) Excludes Asset Retirement Obligations (ARO) of $46 million expected to occur through 2044.

(11) Excludes unrecognized tax benefits of $13 million. At this time, we are unable to make a reasonably reliable estimate of the timing of payments in individual years in connection with these tax liabilities.

(12) Represents TEP’s expected contributions to pension plans in 2018, expected benefit payments for its unfunded Supplemental Executive Retirement Plan (SERP), and expected other postretirement benefit costs to cover medical and life insurance claims as determined by the plans’ actuaries. Due to the significant impact that returns on plan assets and changes in discount rates might have on payment obligation amounts, other contributions beyond 2018 are excluded.

Off-Balance Sheet Arrangements

Other than the unrecorded contractual obligations in the table above, we do not have any arrangements or relationships with entities that are not consolidated into the financial statements.

Income Tax Position

Tax legislation previously in effect included provisions that made qualified property placed in service starting in 2010 eligible for bonus depreciation for tax purposes. In addition, the IRS had issued guidance related to the treatment of expenditures to maintain, replace, or improve property. These provisions were an acceleration of tax benefits we otherwise would have received over 20 years and created net operating loss carryforwards that could have been used to offset future taxable income. As a result, we did not pay any federal or state income taxes in 2017. Under the TCJA, we will not be eligible for bonus depreciation

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for property placed in service after 2017, which will accelerate utilization of net operating loss carryforwards. We offset net operating loss carryforwards against taxable income and do not expect to make federal or state income tax payments until 2020.

In December 2017, the ACC opened a docket requesting that all regulated utilities submit proposals to address passing the benefits of the TCJA through to customers. Any decrease in rates charged to customers related to the TCJA would have a negative impact on TEP's operating cash flows. On February 6, 2018, the ACC ordered utilities to file within 60 days either: (i) an application for a tax adjustor mechanism; (ii) an intent to file a rate case within 90 days; or (iii) any other application to address the effects of the TCJA. TEP expects to file a tax adjustor proposal with the ACC prior to the deadline. TEP cannot predict the outcome of these proceedings or the impact on the Company's financial position or results of operations.

Environmental Matters

The EPA regulates the amount of SO_2, NO_x, CO_2, particulate matter, mercury, and other by-products produced by generation facilities. We may incur additional costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its generation facilities. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, we are unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. Complying with these changes may reduce operating efficiency and increase capital and operating costs.

We capitalized $33 million in 2017, $40 million in 2016, and $33 million in 2015 in costs incurred to comply with environmental rules and regulations. In addition, we recorded operations and maintenance expenses of $5 million in 2017 and $6 million in 2016 and 2015. We expect capital expenditures of $9 million in 2018 and do not expect capital expenditures to be material in years 2019 through 2022. TEP will request recovery from its customers of the costs of environmental compliance through cost recovery mechanisms and Retail Rates.

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as Best Available Retrofit Technology (BART) for certain industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. The rule calls for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on land leased from the Navajo Nation, they are not subject to state oversight; the EPA oversees regional haze planning for these generation facilities.

In the western United States, Regional Haze BART determinations have focused on controls for NO_x, often resulting in a requirement to install Selective Catalytic Reduction (SCR). The BART provisions do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s, after the time frame as designated by the rules. Other provisions of the Regional Haze Rules requiring further emission reductions are not likely to impact Springerville operations until after 2021. In December 2016, the EPA signed a final rule, entitled "Protection of Visibility: Amendments to Requirements for State Plans." Among other things, the rule changes the date for submittal of the next Regional Haze implementation plan from 2018 to 2021. Based on recent Regional Haze requirement time-frames, TEP anticipates that impacts, if any, to Springerville will likely occur three to five years after the 2021 plan submittal date. TEP cannot predict the ultimate outcome of these matters.

Sundt Generating Station

TEP permanently eliminated coal as a fuel source at Sundt to comply with a EPA ruling related to BART.

Four Corners Generating Station

In December 2013, APS, on behalf of the co-owners of Four Corners, notified the EPA that they have chosen an alternative BART compliance strategy. As a result, APS closed Units 1, 2, and 3 in December 2013 and agreed to install SCR on Units 4 and 5. TEP owns 7% of Four Corners Units 4 and 5. TEP's estimated share of NO_x emissions control costs to comply with the rules is $44 million in capital expenditures and $2 million in annual operations and maintenance expenses. The SCR projects are scheduled to be completed by July 2018.

Navajo Generating Station

In August 2014, the EPA published a final Federal Implementation Plan (FIP) which provides that one unit at Navajo will be shut down by 2020, SCR or the equivalent will be installed on the remaining two units by 2030, and conventional coal-fired generation will cease by December 2044. The final BART rule includes options that accommodate potential ownership changes at the facility. The facility has until December 2019 to notify the EPA of how it will comply with the FIP.

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In June 2017, the Navajo Nation approved a land lease extension which allows TEP and the co-owners of Navajo to continue operations through December 2019 and begin decommissioning activities thereafter. As a result of the early retirement of Navajo, TEP and the co-owners will no longer be responsible for implementing the FIP. See Note 1 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to the early retirement of Navajo.

San Juan Generating Station

In October 2014, the EPA published a final rule approving a revised State Implementation Plan (SIP) covering BART requirements for San Juan, which included: (i) the closure of Units 2 and 3 by December 2017; and (ii) the installation of Selective Non-Catalytic Reduction (SNCR) on Units 1 and 4. TEP owns 50% of Units 1 and 2. PNM, the operator of San Juan, completed the installation of SNCR in February 2016 and ceased operations at Units 2 and 3 in December 2017.

In 2017, TEP applied excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order. See Note 2 and Note 3 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information on the early retirement of San Juan Unit 2.

Greenhouse Gas Regulation

In August 2015, the EPA issued the CPP limiting CO_2 emissions from existing and new fossil fueled generation facilities. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets CO_2 emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022.

In October 2017, the EPA issued a proposal to repeal the CPP and in December 2017, the EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) soliciting information about the intent to replace the CPP with a rule establishing new emissions guidelines. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop appropriate responses to the EPA's proposals and compliance strategies as needed. TEP is unable to determine the impact to its facilities until all legal challenges have been resolved and any new regulations have been promulgated.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring disposal of coal ash and other coal combustion residuals to be managed as a solid waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA Subtitle D) for disposal in landfills and/or surface impoundments. We estimate our share of costs to comply to be $2 million at Springerville. The majority of the costs are capital expenditures associated with site preparation and installation of the groundwater monitoring well system. We also expect to incur additional operating costs for on-going groundwater monitoring and eventual site closure activities. Similarly, we currently estimate our share of costs to be $5 million at Four Corners, $3 million at Navajo, and less than $1 million at San Juan, the majority of which are capital expenditures.

In December 2016, Congress approved the Water Infrastructure Improvements for the Nation Act which authorizes the States to establish permit programs under RCRA Subtitle D for implementing regulation for Coal Combustion Residuals (CCR). TEP is currently working with other affected utilities and the Arizona Department of Environmental Quality to explore the possibility of developing a State administered program to enforce CCR regulation.

See Capital Expenditures above for TEP's forecasted environmental compliance costs.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with GAAP requires management to apply accounting policies and to make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements and related notes. Management believes that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional information on TEP’s other significant accounting policies can be found in Note 1 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K.

Accounting for Regulated Operations

We account for our regulated electric operations in accordance with accounting standards that allow the actions of our regulators, the ACC and the FERC, to be reflected in our financial statements. Regulator actions may cause us to capitalize certain costs that would be included as an expense, or in Accumulated Other Comprehensive Income (AOCI), in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in Retail Rates or in rates charged to wholesale customers through transmission tariffs. Regulatory liabilities generally represent expected future costs that have already been collected from customers or amounts that are expected to be returned to customers through billing reductions in future periods. We evaluate regulatory assets and liabilities each period and believe future recovery or settlement is probable. Our assessment includes consideration of recent rate orders, historical regulatory treatment of similar costs, and changes in the regulatory and political environment. If management's assessment is ultimately different than actual regulatory outcomes, the impact on our results of operations, financial position, and future cash flows could be material.

As of December 31, 2017, regulatory liabilities net of regulatory assets on the balance sheet totaled $218 million. There are no current or expected proposals or changes in the regulatory environment that impact our ability to apply accounting guidance for regulated operations. If we conclude, in a future period, that our operations no longer meet the criteria in this guidance, we would reflect our regulatory pension assets in AOCI and recognize the impact of other regulatory assets and liabilities in the income statement, both of which would be material to our financial statements. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding regulatory matters.

Accounting for Asset Retirement Obligations

GAAP requires us to record the fair value of a liability for a legal obligation to retire a long-lived tangible asset in the period in which the liability is incurred. This includes obligations resulting from conditional future events. We incur legal obligations as a result of environmental regulations imposed by State and Federal regulators, contractual agreements, and other factors. To estimate the liability, management must use judgment and assumptions in: determining whether a legal obligation exists to remove assets; estimating the probability of a future event for a conditional obligation; estimating the fair value of the cost of removal; estimating when final removal will occur; and estimating the credit-adjusted risk-free interest rates to be used to discount the future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for AROs. TEP primarily defers costs associated with its legal AROs as regulatory assets because these costs are included in depreciation rates approved for recovery by the ACC. Deferred costs are amortized over the life of the underlying asset.

TEP identified legal obligations to retire generation facilities specified in land leases for its jointly-owned Navajo and Four Corners facilities. These stations reside on land leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at expiration of the leases. TEP also has certain environmental obligations at Luna, San Juan, Sundt and Springerville. TEP estimates that its share of the AROs to remove the Navajo and Four Corners facilities and settle the Luna, San Juan, Sundt, Gila River, and Springerville environmental and contractual obligations will be approximately $155 million at the retirement dates. Additionally, TEP entered into land lease agreements or land easement agreements with certain land owners for the installation of PV assets. The provisions of the PV land leases or land easements require TEP to remove the PV facilities upon expiration of the agreements. In addition, TEP is required to dispose or recycle the PV assets under the Resource Conservation and Recovery Act. TEP's ARO related to the PV assets is estimated to be approximately $31 million at the retirement dates. No other legal obligations to retire generation plant assets have been identified.

TEP has various transmission and distribution lines that operate under land easements and rights-of-way that contain end dates and may contain site restoration clauses. TEP operates transmission and distribution lines as if they will be operated in perpetuity and will continue to be used or sold without land remediation. As such, there are no AROs for these assets.

The total net present value of TEP's ARO liability was $46 million as of December 31, 2017. ARO liabilities are reported in Regulatory and Other Liabilities—Other on the Consolidated Balance Sheets. See Note 3 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding AROs. Additionally, the authorized depreciation rates for TEP include a component designed to accrue the future costs of retiring assets for which no legal obligations exist. The accumulated balances as of December 31, 2017, represent non-legal ARO accruals, less actual removal costs incurred, net of salvage proceeds realized, and are recorded as a regulatory liability on the balance sheet. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding future cost of removal.

Pension and Other Postretirement Benefit Plan Assumptions

TEP records the underfunded amount for its pension and other postretirement obligations as a liability and a regulatory asset to reflect expected recovery of pension and other postretirement obligations through the rates charged to retail customers. As the funded status, discount rates, and actuarial facts change, the liability may vary significantly in future years. Key assumptions used include:

- discount rates used to determine obligations;

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- expected returns on plan assets;
- compensation increases;
- mortality assumptions; and
- healthcare cost trend rates.

Discount Rates

As of December 31, 2017, TEP discounted its future pension plan obligations at 3.7% and its other postretirement plan obligations at a rate of 3.6%. The discount rate for future pension plan and other postretirement plan obligations is determined annually based on the rates currently available on high-quality, non-callable, long-term bonds. The discount rate is based on a corporate yield curve using an average yield between the 60th and 90th percentile of AA-graded U.S. corporate bonds with future cash flows that match the timing and amount of expected future benefit payments.

Expected Returns on Plan Assets

To establish the expected return on assets assumption, TEP reviews the asset allocation and develops return assumptions for each asset class based on advice from an investment consultant and the pension’s actuary that includes both historical performance analysis and forward-looking views of the financial markets. As of December 31, 2017, TEP assumed that its pension plans’ assets would generate a long-term rate of return of 7%.

Compensation Increases

As of December 31, 2017, TEP used a rate of compensation increase of 2.75% to measure pension obligations.

Mortality

The RP-2014 mortality table projected with improvement scale MP-2017 with 15-year convergence and 0.75% long-term rate was utilized to measure the December 31, 2017 pension obligations, whereas improvement scales MP-2016 was utilized for the December 31, 2016 measurement.

Healthcare Cost Trend Rates

TEP used a current year healthcare cost trend rate of 7.6% in valuing its other postretirement benefit obligation as of December 31, 2017. This rate reflects both market conditions and historical experience.

Sensitivity Analysis

The table below shows the effect on TEP's 2017 expense and obligation of a 100 basis point change to its assumptions:

	Effect on Expense		Effect on Obligation	
	Increase	Decrease	Increase	Decrease
(in millions)	December 31, 2017			
Change to Pension				
Discount Rate	$(6)	$ 7	$(65)	$ 83
Long-Term Rate of Return on Plan Assets	(4)	4	N/A	N/A
Change to Other Postretirement Benefits				
Discount Rate	—	1	(8)	10
Long-Term Rate of Return on Plan Assets	—	—	N/A	N/A
Healthcare Cost Trend Rate	1	(1)	7	(6)

In 2018, TEP will incur pension costs of approximately $10 million and other postretirement benefit costs of approximately $6 million. TEP expects to charge approximately $16 million of these costs to operations and maintenance expense, $4 million to capital, and $4 million as a reduction of other expense. TEP expects to make pension plan contributions of $11 million in 2018. In 2018, TEP expects to make benefit payments to retirees under the retiree benefit plan of approximately $5 million and contributions to the Voluntary Employee Beneficiary Association (VEBA) trust of approximately $1 million, net of distributions.

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See Note 8 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for further details regarding TEP's pension plan and other postretirement benefit plan expenses and obligations.

Accounting for Derivative Instruments and Hedging Activities

Commodity Derivative Contracts

TEP enters into forward contracts to purchase or sell capacity or energy at contract prices over a given period of time, typically for one month, three months, or one year, within established limits to meet forecasted load requirements or to take advantage of favorable market opportunities. In general, TEP enters into forward purchase contracts when market conditions provide the opportunity to purchase energy for its load at prices that are below the marginal cost of its supply resources or to supplement its own resources (e.g., during plant outages and summer peaking periods). TEP enters into forward sales contracts when it forecasts that it will have excess supply and the market price of energy exceeds its marginal cost. TEP enters into forward gas commodity price swap agreements to lock in fixed prices on a portion of forecasted gas purchases and to hedge the price risk associated with forward PPAs that are indexed to natural gas prices.

For all commodity derivative instruments that do not meet the normal purchase or normal sale scope exception, we recognize derivative instruments as either assets or liabilities on the balance sheet and measure those instruments at fair value. Unrealized gains and losses on commodity derivative contracts entered into for retail customer load are recorded as either a regulatory asset or regulatory liability on the balance sheet based on our ability to recover the costs of hedging activities entered into to mitigate energy price risk for retail customers. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets through the PPFAC mechanism.

The market prices used to determine fair values for TEP’s derivative instruments as of December 31, 2017, are estimated based on various factors including broker quotes, exchange prices, over the counter prices, and time value. TEP manages the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using a standardized agreement, which allows for the netting of current period exposures to and from a single counterparty.

Interest Rate Swaps

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates tied to London Interbank Offered Rate (LIBOR) on the Springerville Common Facilities lease. As of December 31, 2017, approximately $18 million of variable rate lease debt for the Springerville Common Facilities lease had been hedged through an amortizing interest rate swap expiring in January 2020.

Revenue Recognition

TEP’s retail revenues, which are recognized in the period that electricity is delivered and consumed by customers, include unbilled revenue based on an estimate of kWh delivered at the end of each period. Unbilled revenues are dependent upon a number of factors that require management’s judgment including estimates of retail sales and customer usage patterns. The unbilled revenue is estimated by comparing the estimated kWh delivered to the kWh billed to our retail customers. The excess of estimated kWh delivered over kWh billed is allocated to the retail customer classes based on estimated usage by each customer class. We then record revenue for each customer class based on the various Retail Rates for each customer class. Due to the seasonal fluctuations of TEP’s actual load, unbilled revenues increase during the spring and summer and decrease during the fall and winter. A provision for uncollectible accounts, associated with retail revenues, is recorded as a component of operations and maintenance expense.

Plant Asset Depreciable Lives

TEP has significant investments in electric generation assets and electric transmission and distribution assets. We calculate depreciation expense based on our estimate of the useful lives of our plant assets and expected net removal costs. The useful lives of plant assets are further detailed in Note 3 of Notes to Consolidated Financial Statements in

Part II, Item 8 of this Form 10-K. Changes to depreciation estimates resulting from a change of estimated service life or removal costs could have a significant impact on the amount of depreciation expense recorded in the income statement. The ACC approves depreciation rates for all generation and distribution assets. Depreciation rates for such assets cannot be changed without the ACC's approval. TEP's transmission assets are subject to the jurisdiction of the FERC. See Note 1 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding depreciation rates.

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Income Taxes

Due to the differences between GAAP and income tax laws, many transactions are treated differently for income tax purposes than they are in the financial statements. We account for this difference by recording deferred income tax assets and liabilities using the effective income tax rate as of our balance sheet date. TEP records income tax liabilities based on TEP's taxable income as reported in the consolidated tax return of FortisUS, Inc., a Fortis intermediate holding company (FortisUS).

A valuation allowance is established against deferred tax assets for which management believes it is more likely than not that the deferred asset will not be realized. In making this judgment, management evaluates all available evidence and gives more weight to objective verifiable evidence. TEP recorded no valuation allowance as of December 31, 2017. See Note 12 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding income taxes.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

For a discussion of new accounting pronouncements affecting TEP, see Note 13 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

TEP’s financial statements are exposed to certain market risks which can impact asset and liability fair value, results of operations, and cash flows. TEP's significant market risks are primarily associated with interest rates, commodity and coal prices, and extension of credit to counterparties. TEP may enter into interest rate swaps and financing transactions to manage changes in interest rates. TEP has a Risk Management Committee responsible for the oversight of commodity price risk and credit risk related to wholesale energy marketing and power procurement activities. To limit TEP’s exposure to commodity price risk, the Risk Management Committee sets trading and hedging policies and limits, which are reviewed frequently to respond to constantly changing market conditions. To limit TEP’s exposure to credit risk, the Risk Management Committee reviews counterparty credit exposure as well as credit policies and limits.

See Forward-Looking Information for additional information.

Interest Rate Risk

Long-Term Debt

TEP is exposed to interest rate risk resulting from changes in interest rates on certain variable rate debt obligations. TEP had $137 million in tax-exempt variable rate debt outstanding as of December 31, 2017. The outstanding debt included one series of bonds for which interest rates are reset weekly and one series of bonds for which interest rates are reset monthly. The weighted average weekly rate (including LOC fees and remarketing fees) was 1.76% in 2017 and 1.33% in 2016. The average weekly interest rate ranged from 1.53% - 2.68% in 2017 and 0.93% - 1.76% in 2016. The monthly rate is based on a percentage of an index equal to one-month LIBOR plus a credit spread. The average monthly rate was 1.41% in 2017 and 1.01% in 2016. The monthly rate ranged from 1.08% - 1.58% in 2017 and 0.83% - 1.08% in 2016.

TEP is subject to volatility in its tax-exempt variable rate debt. A 100 basis point increase in average interest rates on this debt, over a twelve-month period, would result in a decrease in TEP’s pre-tax net income of approximately $1 million.

TEP had $21 million of variable rate debt outstanding related to the Springerville Common Facilities capital lease obligation as of December 31, 2017. TEP has one fixed-for-floating interest rate swap in place to hedge the floating interest rate risk associated with a portion of the capital lease obligation. The notional amount of the swap was $18 million as of December 31, 2017.

Interest Rate Swap

To adjust the value of TEP's interest rate swap, classified as a cash flow hedge, to fair value in Other Comprehensive Income, TEP recorded the following net unrealized gains:

(in millions)	2017	2016	2015
Net Unrealized Gains	$ 1	$ 1	$ 1

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Credit Facilities

TEP is subject to interest rate risk resulting from changes in interest rates on borrowings under its credit agreement. The interest paid on borrowings is variable. Revolving credit borrowings are made on either the basis of a spread over LIBOR or an Alternate Base Rate (ABR). As a result, TEP may experience significant volatility in the rates paid on LIBOR borrowings under its revolving credit facilities.

Commodity and Coal Price Risk

TEP is exposed to market fluctuations in electricity, natural gas and coal prices as a result of its obligation to serve retail customer load in its regulated service territory and long-term wholesale contracts. TEP's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity and coal prices may be subject to significant price changes as supply and demand are impacted by, among other unpredictable factors, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Under the guidance of the Risk Management Committee, TEP mitigates a portion of its commodity price risk through the use of commodity contracts, which include forwards, options, swaps and other agreements, to effectively secure future supply, fix fluctuating commodity prices, or sell future production generally at fixed prices. TEP's exposure to commodity and coal price risk is limited by its ability to include these costs in regulated rates through its PPFAC mechanism, which is subject to review by the ACC. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to the PPFAC mechanism.

Certain commodity contracts qualify as derivatives and are recorded at fair value. The changes in fair value of such contracts have a high correlation to price changes in the hedged commodities. The following table shows the changes in fair value of our derivative positions:

(in millions)	2017	2016	2015
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$(18)	$ 12	$ 6

TEP's derivative contracts mature on various dates through 2029. The table below displays the valuation methodologies and maturities of TEP's derivative contracts by source of fair value:

	Unrealized Gain (Loss) of TEP's Hedging Activities			
	Maturity 0 – 6 months	Maturity 6 – 12 months	Maturity over 1 yr.	Total Unrealized Gain (Loss)
(in millions)	December 31, 2017			
Prices Actively Quoted	$ —	$ (7)	$ (8)	$ (15)

Sensitivity Analysis of Derivatives

TEP uses sensitivity analysis to measure the potential impact of favorable and unfavorable changes in market prices on the fair value of its derivative contracts. TEP records unrealized gains and losses as either a regulatory asset or regulatory liability. As contracts settle, the unrealized gains and losses are reversed and realized gains or losses are recorded to the PPFAC. For TEP's derivatives related to the purchase and sale of electricity, a 10% change in the market price of purchased power would affect unrealized positions reported as a regulatory asset or regulatory liability by approximately $1 million; for derivatives related to the natural gas price hedges, a 10% change in the market price of energy would affect unrealized positions reported as a regulatory asset or liability by approximately $38 million.

Coal Supply Agreements

TEP is subject to fuel price risk from changes in the price of coal used to fuel its coal-fired generation facilities. This risk is mitigated through the use of long-term coal supply agreements with limited price movement. Coal agreements expire from 2020 through 2031. TEP expects coal reserves from the supplying mines to be sufficient to fulfill the estimated requirements for each coal-fired generation facility's estimated remaining life. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources and Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

Credit Risk

TEP is exposed to credit risk in its energy-related marketing activities related to potential non-performance by counterparties. TEP manages the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures,

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requiring collateral when needed, and using standard agreements which allow for the netting of current period exposures to and from a single counterparty. Counterparty credit exposure is calculated by adding any outstanding receivable (net of amounts payable if a netting agreement exists) to the mark-to-market value of any forward contracts. If exposure exceeds credit limits or contractual collateral thresholds, we may request that a counterparty provide credit enhancement in the form of cash collateral or an LOC.

TEP has entered into short-term and long-term transactions related to its wholesale marketing and gas hedging activities with various counterparties. As of December 31, 2017, TEP's total credit exposure was approximately $12 million. TEP had approximately $1 million of exposure to non-investment grade counterparties.

As of December 31, 2017, TEP posted no cash collateral nor LOCs as credit enhancements with its counterparties, and TEP holds approximately $6 million in collateral from its wholesale counterparties.

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm
To the Stockholder and the Board of Directors of
Tucson Electric Power Company
Tucson, AZ

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheet of Tucson Electric Power Company (the "Company") as of December 31, 2017, the related consolidated statements of income, comprehensive income, changes in stockholder's equity, and cash flows, for the year ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for the year ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.
Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.
Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP
Phoenix, Arizona
February 15, 2018

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Tucson Electric Power Company:

We have audited the accompanying consolidated balance sheets of Tucson Electric Power Company as of December 31, 2016, and the related consolidated statements of income, comprehensive income, changes in stockholder’s equity and cash flows for each of the two years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company’s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provided a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tucson Electric Power Company at December 31, 2016, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP
Ernst & Young LLP
Calgary, Canada
February 16, 2017

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Amounts in thousands)

	Years Ended December 31,		
	2017	2016	2015
Operating Revenues			
Retail	$1,040,682	$989,580	$1,021,543
Wholesale	174,742	117,341	167,020
Other	125,511	128,074	117,981
Total Operating Revenues	1,340,935	1,234,995	1,306,544
Operating Expenses			
Fuel	285,551	289,862	305,559
Purchased Power	136,425	85,354	124,764
Transmission and Other PPFAC Recoverable Costs	36,239	23,781	24,798
Increase (Decrease) to Reflect PPFAC Recovery Treatment	(32,660)	21,064	39,787
Total Fuel and Purchased Power	425,555	420,061	494,908
Operations and Maintenance	360,302	353,905	345,356
Depreciation	152,874	146,097	138,093
Amortization	22,255	22,498	19,261
Taxes Other Than Income Taxes	53,623	49,303	49,623
Total Operating Expenses	1,014,609	991,864	1,047,241
Operating Income	326,326	243,131	259,303
Other Income (Deductions)			
Interest Income	742	111	93
Other Income	14,128	5,636	6,647
Other Expense	(3,344)	(3,019)	(2,833)
Appreciation (Depreciation) in Value of Investments	2,791	2,147	(142)
Total Other Income (Deductions)	14,317	4,875	3,765
Interest Expense			
Long-Term Debt	62,018	62,015	61,159
Capital Leases	2,554	3,356	3,994
Other Interest Expense	718	531	1,134
Interest Capitalized	(2,078)	(1,710)	(2,732)
Total Interest Expense	63,212	64,192	63,555
Income Before Income Taxes	277,431	183,814	199,513
Income Tax Expense	100,763	59,376	71,719
Net Income	$176,668	$124,438	$127,794

The accompanying notes are an integral part of these financial statements.

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TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in thousands)

	Years Ended December 31,		
	2017	2016	2015
Comprehensive Income			
Net Income	$176,668	$124,438	$127,794
Other Comprehensive Income			
Net Changes in Fair Value of Cash Flow Hedges:			
Net of Income Tax (Expense) Benefit of $(305), $(420), and $(821)	485	652	1,261
Supplemental Executive Retirement Plan Adjustments:			
Net of Income Tax (Expense) Benefit of $637, $399, and $(63)	(2,156)	(643)	101
Total Other Comprehensive Income, Net of Tax	(1,671)	9	1,362
Total Comprehensive Income	$174,997	$124,447	$129,156

The accompanying notes are an integral part of these financial statements.

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TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Years Ended December 31,		
	2017	2016	2015
Cash Flows from Operating Activities			
Net Income	$176,668	$124,438	$127,794
Adjustments to Reconcile Net Income To Net Cash Flows from Operating Activities:			
Depreciation Expense	152,874	146,097	138,093
Amortization Expense	22,255	22,498	19,261
Amortization of Debt Issuance Costs	2,349	2,853	3,043
Use of Renewable Energy Credits for Compliance	25,453	17,618	19,731
Deferred Income Taxes	100,762	59,367	72,026
Pension and Other Postretirement Benefits Expense	16,039	15,338	18,588
Pension and Other Postretirement Benefits Funding	(14,430)	(13,459)	(30,682)
Allowance for Equity Funds Used During Construction	(5,322)	(4,522)	(5,352)
FERC Transmission Refund Payable	(4,878)	4,878	—
Changes in Current Assets and Current Liabilities:			
Accounts Receivable	(13,219)	7,809	(3,019)
Materials, Supplies, and Fuel Inventory	175	7,627	(8,758)
Regulatory Assets	(3,942)	(12,147)	18,002
Accounts Payable and Accrued Charges	9,790	14,284	(13,917)
Regulatory Liabilities	(20,227)	18,012	10,921
Other, Net	3,977	14,777	(797)
Net Cash Flows—Operating Activities	448,324	425,468	364,934
Cash Flows from Investing Activities			
Capital Expenditures	(345,617)	(250,360)	(333,841)
Purchase, Springerville Coal Handling Facilities Lease Assets	—	—	(120,312)
Purchase, Springerville Unit 1 Assets	—	(85,000)	(45,753)
Purchase Intangibles, Renewable Energy Credits	(51,179)	(40,949)	(29,184)
Proceeds from Sale, Springerville Coal Handling Facilities	—	—	23,656
Contributions in Aid of Construction	4,983	3,432	4,517
Net Cash Flows—Investing Activities	(391,813)	(372,877)	(500,917)
Cash Flows from Financing Activities			
Proceeds from Borrowings, Revolving Credit Facility	70,000	—	148,000
Repayments of Borrowings, Revolving Credit Facility	(35,000)	—	(233,000)
Proceeds from Borrowings, Term Loan	—	—	130,000
Repayments of Borrowings, Term Loan	—	—	(130,000)
Proceeds from Issuance, Long-Term Debt	—	—	299,019
Repayments, Long-Term Debt	—	—	(208,600)
Dividends Paid to Parent	(70,000)	(50,000)	(50,000)
Payments of Capital Lease Obligations	(15,571)	(14,079)	(13,464)
Payment of Debt Issuance/Retirement Costs	(245)	(183)	(3,942)
Contribution from Parent	—	—	180,000

Other, Net	481	(4,871)	1,458
Net Cash Flows—Financing Activities	(50,335)	(69,133)	119,471
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	6,176	(16,542)	(16,512)
Cash, Cash Equivalents, and Restricted Cash, Beginning of Period	43,325	59,867	76,379
Cash, Cash Equivalents, and Restricted Cash, End of Period	$49,501	$43,325	$59,867

The accompanying notes are an integral part of these financial statements.

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TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Amounts in thousands, except share data)

	December 31, 2017	December 31, 2016
ASSETS		
Utility Plant		
Plant in Service	$5,780,805	$5,975,139
Utility Plant Under Capital Leases	84,870	167,413
Construction Work in Progress	160,288	129,955
Total Utility Plant	6,025,963	6,272,507
Accumulated Depreciation and Amortization	(2,193,656)	(2,385,053)
Accumulated Amortization of Capital Lease Assets	(63,605)	(104,648)
Total Utility Plant, Net	3,768,702	3,782,806
Investments and Other Property	51,260	45,020
Current Assets		
Cash and Cash Equivalents	37,701	35,962
Accounts Receivable, Net	137,932	124,934
Fuel Inventory	25,059	25,887
Materials and Supplies	103,981	97,126
Regulatory Assets	93,960	56,340
Derivative Instruments	3,187	4,966
Other	10,777	13,793
Total Current Assets	412,597	359,008
Regulatory and Other Assets		
Regulatory Assets	293,551	225,453
Derivative Instruments	8,826	330
Other	55,313	37,372
Total Regulatory and Other Assets	357,690	263,155
Total Assets	$4,590,249	$4,449,989

The accompanying notes are an integral part of these financial statements.

(Continued)

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TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Amounts in thousands, except share data)

	December 31, 2017	December 31, 2016
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity:		
Common Stock (No Par Value, 75,000,000 Shares Authorized, 32,139,434 Shares Outstanding as of December 31, 2017 and 2016)	$1,296,539	$1,296,539
Capital Stock Expense	(6,357)	(6,357)
Retained Earnings	380,076	273,408
Accumulated Other Comprehensive Loss	(6,226)	(4,555)
Total Common Stock Equity	1,664,032	1,559,035
Preferred Stock (No Par Value, 1,000,000 Shares Authorized, None Outstanding as of December 31, 2017 and 2016)	—	—
Capital Lease Obligations	28,519	39,267
Long-Term Debt, Net	1,354,423	1,453,072
Total Capitalization	3,046,974	3,051,374
Current Liabilities		
Current Maturities of Long-Term Debt	100,000	—
Borrowings Under Revolving Credit Facility	35,000	—
Capital Lease Obligations	10,749	51,765
Accounts Payable	97,367	89,797
Accrued Taxes Other than Income Taxes	40,706	37,639
Accrued Employee Expenses	30,929	29,465
Accrued Interest	14,750	14,508
Regulatory Liabilities	89,024	76,069
Customer Deposits	24,865	25,778
Derivative Instruments	10,667	2,641
Other	18,119	17,837
Total Current Liabilities	472,176	345,499
Regulatory and Other Liabilities		
Deferred Income Taxes, Net	300,258	529,148
Regulatory Liabilities	516,438	300,700
Pension and Other Postretirement Benefits	133,799	131,630
Derivative Instruments	17,907	2,629
Other	102,697	89,009
Total Regulatory and Other Liabilities	1,071,099	1,053,116
Commitments and Contingencies		
Total Capitalization and Other Liabilities	$4,590,249	$4,449,989

The accompanying notes are an integral part of these financial statements.

(Concluded)

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TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDER'S EQUITY
(Amounts in thousands)

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances as of December 31, 2014	$1,116,539	$(6,357)	$111,523	$ (5,926)	$ 1,215,779
Net Income			127,794		127,794
Other Comprehensive Income, Net of Tax				1,362	1,362
Dividends Declared to Parent			(50,000)		(50,000)
Contribution from Parent	180,000				180,000
Balances as of December 31, 2015	1,296,539	(6,357)	189,317	(4,564)	1,474,935
Net Income			124,438		124,438
Other Comprehensive Income, Net of Tax				9	9
Dividends Declared to Parent			(50,000)		(50,000)
Adoption of ASU, Cumulative Effect Adjustment			9,653		9,653
Balances as of December 31, 2016	1,296,539	(6,357)	273,408	(4,555)	1,559,035
Net Income			176,668		176,668
Other Comprehensive Income, Net of Tax				(1,671)	(1,671)
Dividends Declared to Parent			(70,000)		(70,000)
Balances as of December 31, 2017	$1,296,539	$(6,357)	$380,076	$ (6,226)	$ 1,664,032

The accompanying notes are an integral part of these financial statements.

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NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

TEP is a regulated utility that generates, transmits, and distributes electricity to approximately 422,000 retail customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. TEP is a wholly owned subsidiary of UNS Energy, a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis.

BASIS OF PRESENTATION

TEP's consolidated financial statements and disclosures are presented in accordance with GAAP, including specific accounting guidance for regulated operations. The consolidated financial statements include the accounts of TEP and its subsidiaries. In the consolidation process, accounts of the parent and subsidiaries are combined and intercompany balances and transactions are eliminated. TEP jointly owns several generation and transmission facilities with both affiliated and non-affiliated entities. TEP's proportionate share of jointly-owned facilities is recorded in Utility Plant on the Consolidated Balance Sheets, and its proportionate share of the operating costs associated with these facilities is included in the Consolidated Statements of Income. See Note 3 for additional information regarding utility plant.
Certain amounts from prior periods have been reclassified to conform to the current year presentation.

Accounting for Regulated Operations

TEP applies accounting standards that recognize the economic effects of rate regulation. As a result, TEP capitalizes certain costs that would be recorded as expense or in AOCI by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in Retail Rates or in rates charged to wholesale customers through transmission tariffs. Regulatory liabilities generally represent expected future costs that have already been collected from customers or amounts that are expected to be returned to customers through billing reductions in future periods.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process. TEP evaluates regulatory assets and liabilities each period and believes future recovery or settlement is probable. If future recovery of costs ceases to be probable, the assets would be written off as a charge to current period earnings or AOCI. See Note 2 for additional information regarding regulatory matters.

TEP applies regulatory accounting as the following conditions exist:

- An independent regulator sets rates;
- The regulator sets the rates to recover the specific enterprise’s costs of providing service; and
- Rates are set at levels that will recover the entity’s costs and can be charged to and collected from ratepayers.

Variable Interest Entities

TEP regularly reviews contracts to determine if it has a variable interest in an entity, if that entity is a Variable Interest Entity (VIE), and if it is the primary beneficiary of the VIE. The primary beneficiary is required to consolidate the VIE when the variable interest holder has: (i) the power to direct activities that most significantly impact the economic performance of the VIE; and (ii) the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE.

TEP routinely enters into long-term renewable PPAs with various entities. Some of these entities are VIEs due to the long-term fixed price component in the agreements. These PPAs effectively transfer commodity price risk to TEP, the buyer of the power, creating a variable interest. TEP has determined it is not a primary beneficiary as it lacks the power to direct the activities that most significantly impact the economic performance of the VIEs. TEP reconsiders whether it is a primary beneficiary of the VIEs on a quarterly basis.

As of December 31, 2017, the carrying amount of assets and liabilities in the balance sheet that relates to variable interests under long-term PPAs is predominantly related to working capital accounts and generally represents the amounts owed by TEP for the deliveries associated with the current billing cycle. TEP's maximum exposure to loss is limited to the cost of replacing the power if the providers do not meet the production guarantee. However, the exposure to loss is mitigated as the Company would likely recover these costs through retail customer cost recovery mechanisms. See Note 2 for additional information related to cost recovery mechanisms.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

Effective January 1, 2017, TEP adopted accounting guidance that requires the Company to measure inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The adoption of this change in accounting principle did not have any impact on TEP's financial position or results of operations as the Company recovers the cost of inventory through its rates.

Effective December 31, 2017, TEP early adopted accounting guidance that requires entities to show the changes in the total of cash, cash equivalents, and restricted cash or restricted cash equivalents on the cash flow statement. As a result, TEP no longer presents transfers between cash and cash equivalents and restricted cash and restricted cash equivalents on the cash flow statement. On adoption, using the retrospective method of transition, TEP's Consolidated Statements of Cash Flows included the following adjustments:

(in millions)	As Filed	Adoption of ASU Impacts	As Adjusted
	Year Ended December 31, 2016		
Net Cash Flows—Operating Activities	$425	$ —	$ 425
Net Cash Flows—Investing Activities	(376)	3	(373)
Net Cash Flows—Financing Activities	(69)	—	(69)
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	(20)	3	(17)
Cash, Cash Equivalents, and Restricted Cash, Beginning of Period	56	4	60
Cash, Cash Equivalents, and Restricted Cash, End of Period	$36	$ 7	$ 43
(in millions)	Year Ended December 31, 2015		
Net Cash Flows—Operating Activities	$365	$—	$365
Net Cash Flows—Investing Activities	(503)	2	(501)
Net Cash Flows—Financing Activities	120	—	120
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	(18)	2	(16)
Cash, Cash Equivalents, and Restricted Cash, Beginning of Period	74	2	76
Cash, Cash Equivalents, and Restricted Cash, End of Period	$56	$4	$60

The standard impacted the presentation of the cash flow statement but did not have an impact on TEP's financial position or results of operations.

USE OF ACCOUNTING ESTIMATES

Management uses estimates and assumptions when preparing financial statements according to GAAP. These estimates and assumptions affect:

- assets and liabilities in the balance sheet at the dates of the financial statements;
- disclosures about contingent assets and liabilities at the dates of the financial statements; and
- revenues and expenses in the income statement during the periods presented.

Because these estimates involve judgments based upon the Company's evaluation of relevant facts and circumstances, actual results may differ from these estimates.

Asset Retirement Obligations

TEP has identified legal AROs related to the retirement of certain generation assets. Additionally, TEP incurred AROs related to its PV assets as a result of entering into various land leases or land easement agreements. Liabilities are recorded for legal AROs in the period in which they are incurred if it can be reasonably estimated. When a new obligation is recorded, the cost of the liability is capitalized by increasing the carrying amount of the related long-lived asset. The increase in the liability due to the passage of time is recorded by recognizing accretion expense in Operations and Maintenance Expense on the Consolidated Statements of Income. Capitalized cost is depreciated over the useful life of the related asset or, when applicable, the term of the lease. TEP primarily defers the accretion and depreciation expense associated with its legal AROs as regulatory assets based on the ACC approval of these costs in its depreciation rates.

Depreciation rates also include a component for estimated future removal costs that have not been identified as legal obligations. TEP recovers estimated future removal costs in Retail Rates and records an obligation for estimated costs of removal as regulatory liabilities.

Contingencies

Reserves for specific legal proceedings are established when the likelihood of an unfavorable outcome is probable and the amount of loss can be reasonably estimated. Significant judgment is required in predicting the outcome of these suits and claims, many of which take years to complete. TEP identifies certain other legal matters where the Company believes an unfavorable outcome is reasonably possible or no estimate of possible losses can be made. All contingencies are regularly reviewed to determine whether the likelihood of loss has changed and to assess whether a reasonable estimate of the loss or range of loss can be made.

CASH AND CASH EQUIVALENTS

TEP considers all highly liquid investments with a remaining maturity of three months or less at acquisition to be cash equivalents.

RESTRICTED CASH

Restricted cash includes cash balances restricted regarding withdrawal or usage based on contractual or regulatory considerations. The following table presents the line items and amounts of cash, cash equivalents, and restricted cash reported on the balance sheet and reconciles their sum to the cash flow statement:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Cash and Cash Equivalents	$38	$ 36	$ 56
Restricted Cash included in:			
Investments and Other Property	11	7	4
Current Assets, Other	1	—	—
Total Cash, Cash Equivalents, and Restricted Cash	$50	$ 43	$ 60

Restricted cash included in Investments and Other Property on the Consolidated Balance Sheets represents cash contractually required to be set aside to pay TEP's share of mine reclamation costs at San Juan. Restricted cash included in Current Assets—Other represents cash required to be set aside by various contractual agreements.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

TEP records an allowance for doubtful accounts to reduce accounts receivable for amounts estimated to be uncollectible. The allowance is determined based on historical bad debt patterns, retail sales, and economic conditions. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible. The change in the balance of the Allowance for Doubtful Accounts included in Accounts Receivable, Net on the Consolidated Balance Sheets is summarized as follows:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Beginning of Period	$5	$27	$5
Additions Charged to Cost and Expense	3	4	2
Write-offs	(3)	(3)	(3)
Provision for Springerville Unit 1, Third-Party Owners	—	(23)	23
End of Period	$5	$5	$27

The allowance for doubtful accounts decreased in 2016 due to the settlement and release of asserted claims between TEP and the Third-Party Owners related to Springerville Unit 1. See Note 7 for additional information regarding the settlement of the Third-Party Owners' claims.

INVENTORY

TEP values materials, supplies, and fuel inventory at the lower of weighted average cost and net realizable value. Materials and supplies consist of generation, transmission, and distribution construction and repair materials. The majority of TEP's inventory will be recovered in rates charged to ratepayers. Handling and procurement costs (such as labor, overhead costs, and transportation costs) are capitalized as part of the cost of the inventory.

UTILITY PLANT

Utility plant includes the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. Utility plant is reported at original cost. Original cost includes materials and labor, contractor services, construction overhead (when applicable), and an Allowance for Funds Used During Construction (AFUDC), less contributions in aid of construction.

The cost of repairs and maintenance, including planned generation overhauls, are expensed to Operations and Maintenance Expense on the Consolidated Statements of Income as costs are incurred.

When TEP retires a unit of regulated property, accumulated depreciation is reduced by the original cost plus removal costs less any salvage value. There is no impact to the income statement.

AFUDC and Capitalized Interest

AFUDC reflects the cost of debt and equity funds used to finance construction and is capitalized as part of the cost of regulated utility plant. AFUDC amounts are capitalized and amortized through depreciation expense as a recoverable cost in Retail Rates. The capitalized interest that relates to debt is recorded as a reduction in Interest Expense on the Consolidated Statements of Income. The capitalized cost for equity funds is recorded in Other Income on the Consolidated Statements of Income.

The average AFUDC rates on regulated construction expenditures are included in the table below:

	2017	2016	2015
Average AFUDC Rates	7.31%	7.47%	6.12%

Depreciation

Depreciation is recorded for owned utility plant on a group method straight-line basis at depreciation rates based on the economic lives of the assets. See Note 3 for additional information regarding utility plant. The ACC approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the FERC. Depreciation rates are based on average useful lives and include estimates for salvage value and removal costs. Below are the summarized average annual depreciation rates for all utility plant:

	2017	2016	2015
Average Annual Depreciation Rates	2.97%	2.85%	2.83%

Utility Plant Under Capital Leases

TEP finances a portion of the Springerville Common Facilities with capital leases. Capital lease expense is recorded in Amortization Expense and in Interest Expense—Capital Leases on the Consolidated Statements of Income. See Note 3 for additional information regarding utility plant and Note 6 for additional information related to the lease terms.

Computer Software Costs

Costs incurred to purchase and develop internal use computer software are capitalized and amortized over the estimated economic life of the product. If the software is no longer useful or impaired, the carrying value is reduced and recorded as an expense on the income statement.

EVALUATION OF ASSETS FOR IMPAIRMENT

Long-lived assets and investments are evaluated for impairment whenever events or circumstances indicate the carrying value of the assets may be impaired. If expected future cash flows (without discounting) are less than the carrying value of the asset, an impairment loss is recognized if the impairment is other-than-temporary and the loss is not recoverable through rates.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEFERRED FINANCING COSTS

Using the effective interest method, costs to issue debt are deferred and amortized to interest expense on a straight-line basis over the life of the debt. Deferred debt issuance costs are presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees, and printing costs.

TEP accounts for debt issuance costs related to credit facility arrangements as an asset.

The gains and losses on reacquired debt associated with regulated operations are deferred and amortized to interest expense over the remaining life of the original debt.

OPERATING REVENUES

Revenues related to the sale of energy are recognized when services or commodities are delivered to customers. The billing for the delivery of power to retail customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Operating revenues include an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period. At the end of the month, amounts of energy delivered since the last meter reading are estimated and the corresponding unbilled revenue is calculated using average customer Retail Rates.

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events, if certain criteria are met. TEP charges customers the ACC-authorized tariff price plus separate ACC-authorized surcharges. TEP has identified its LFCR mechanism and DSM performance incentive as alternative revenues. The LFCR mechanism provides for recovery of certain non-fuel costs that would go unrecovered due to reduced retail kWh sales as a result of implementing ACC-approved energy efficiency programs and customer-installed DG. The LFCR surcharge is assessed as a percentage of the customer's bill. Revenue recognition related to the LFCR mechanism creates a regulatory asset until such time as the revenue is collected. For recovery of the LFCR regulatory asset, TEP is required to file an annual LFCR adjustment request with the ACC for the LFCR revenues recognized in the prior year. The recovery is subject to a year-over-year cap of 2% of TEP's applicable retail revenues, as approved in the 2017 Rate Order. In addition, the ACC approves a new DSM surcharge annually, which is effective June 1 of each year, to compensate TEP for the costs to design and implement cost-effective energy efficiency and demand response programs until such costs are reflected in TEP's non-fuel base rates as well as a performance incentive. TEP collects the DSM surcharge on a per kWh basis for residential customers and on a percentage of bill basis for non-residential customers. See Note 2 for additional information regarding regulatory matters.

For purchased power and wholesale sales contracts that are settled financially, TEP nets the purchased power contracts with the sales contracts and reflects the amount in Wholesale Revenues on the Consolidated Statements of Income.

TEP recognizes monthly management fees in Other Revenues on the Consolidated Statements of Income as the operator of Springerville Unit 3 on behalf of Tri-State and Springerville Unit 4 on behalf of SRP. Additionally, Other Revenues includes reimbursements from Tri-State and SRP for various operating expenses at Springerville and for the use of the Springerville Common Facilities and Springerville Coal Handling Facilities. The offsetting expenses are recorded in their respective line items on the income statement based on the nature of services provided. As the operating agent for Tri-State, TEP may earn performance incentives based on unit availability which are recognized in Other Revenues on the Consolidated Statements of Income in the period earned.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

TEP recovers the actual fuel, purchased power, and transmission costs to provide electric service to retail customers through base fuel rates and through a PPFAC mechanism. The ACC periodically adjusts the PPFAC rate at which TEP recovers these costs. The difference between costs recovered through rates and actual fuel, purchased power, transmission, and other approved costs to provide retail electric service is deferred. Cost over-recoveries are deferred as regulatory liabilities and cost under-recoveries are deferred as regulatory assets. See Note 2 for additional information regarding regulatory matters.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAMS

The ACC’s RES requires Arizona regulated utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements by 2025, with DG accounting for 30% of the annual renewable energy requirement. Arizona utilities must file an annual RES implementation plan for review and approval by the ACC. The approved costs of carrying out this plan are recovered from retail customers through the RES surcharge. The associated lost revenues attributable to meeting DG targets will be partially recovered through the LFCR mechanism.

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TEP is required to implement cost-effective DSM programs to comply with the ACC’s EE Standards. The EE Standards provide regulated utilities a DSM surcharge to recover from retail customers the costs to implement DSM programs. The EE Standards require increasing annual targeted retail kWh savings equal to 22% by 2020.

Any RES or DSM surcharges collected above or below the costs incurred to implement the plans are deferred and reflected in the balance sheet as a regulatory liability or asset. TEP recognizes RES and DSM surcharge revenue in Retail Revenues on the Consolidated Statements of Income in amounts necessary to offset recognized qualifying expenditures.

RENEWABLE ENERGY CREDITS

The ACC measures compliance with the RES requirements through RECs. A REC represents one kWh generated from renewable resources. When TEP purchases renewable energy, the premium paid above the market cost of conventional power equals the REC cost recoverable through the RES surcharge. As described above, the market cost of conventional power is recoverable through the PPFAC mechanism.

When RECs are purchased, TEP records the cost of the RECs (an indefinite-lived intangible asset) as other assets and a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, TEP recognizes purchased power expense and other revenues in an equal amount. TEP had $42 million and $24 million of RECs as of December 31, 2017 and 2016, respectively. RECs are included in Regulatory and Other Assets—Other on the Consolidated Balance Sheets. See Note 2 for additional information regarding regulatory matters.

TAXES OTHER THAN INCOME TAXES

TEP acts as a conduit or collection agent for sales taxes, utility taxes, franchise fees, and regulatory assessments. Trade receivables are recorded as the Company bills customers for these taxes and assessments. Simultaneously, liabilities payable to governmental agencies are recorded in the balance sheet for these taxes and assessments. These amounts are not reflected in the income statement.

INCOME TAXES

Due to the difference between GAAP and income tax laws, many transactions are treated differently for income tax purposes than for financial statement presentation purposes. Temporary differences are accounted for by recording deferred income tax assets and liabilities on the balance sheet. These assets and liabilities are recorded using enacted income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. TEP reduces deferred tax assets by a valuation allowance when, in the opinion of management, it is more likely than not some portion, or the entire deferred income tax asset, will not be realized.

Tax benefits are recognized when it is more likely than not that a tax position will be sustained upon examination by the tax authorities based on the technical merits of the position. The tax benefit recorded is the largest amount that is more than 50% likely to be realized upon ultimate settlement with the tax authority, assuming full knowledge of the position and all relevant facts. Interest expense accruals relating to income tax obligations are recorded in Other Interest Expense on the Consolidated Statements of Income.

TEP accounts for federal energy credits generated prior to 2012 using the grant accounting model. The credit is treated as deferred revenue, which is recognized over the depreciable life of the underlying asset. The deferred tax benefit of the credit is treated as a reduction to income tax expense in the year the credit arises. Federal energy credits generated since 2012 are deferred as regulatory liabilities and amortized as a reduction in income tax expense over the tax life of the underlying asset. Income tax expense attributable to the reduction in tax basis is accounted for in the year the federal energy credit is generated and is deferred as a regulatory asset. All other federal and state income tax credits are treated as a reduction to income tax expense in the year the credit arises.

TEP records income tax liabilities based on TEP's taxable income as reported in the consolidated tax return of FortisUS.

PENSION AND OTHER POSTRETIREMENT BENEFITS

TEP sponsors noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on years of service and average compensation. The Company also provides limited healthcare and life insurance benefits for retirees.

The Company recognizes the underfunded status of defined benefit pension plans as a liability in the balance sheet. The underfunded status is measured as the difference between the fair value of the pension plans' assets and the projected benefit obligation for the pension plans. TEP recognizes a regulatory asset to the extent these future costs are probable of recovery in the rates charged to retail customers. The Company expects recovery of these costs over the estimated service lives of employees.

Additionally, TEP maintains a SERP for senior management. Changes in SERP benefit obligations are recognized as a component of AOCI.

Pension and other postretirement benefit expenses are determined by actuarial valuations based on assumptions that the Company evaluates annually. See Note 8 for additional information regarding the employee benefit plans.

FAIR VALUE

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange, and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange. See Note 11 for additional information regarding fair value.

DERIVATIVE INSTRUMENTS

The Company uses various physical and financial derivative instruments, including forward contracts, financial swaps, and call and put options, to meet forecasted load and reserve requirements, to reduce exposure to energy commodity price volatility, and to hedge interest rate risk exposure. Derivative instruments that do not meet the normal purchase or normal sale scope exception will be recognized as either assets or liabilities on the balance sheet and are measured at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not recorded at fair value and settled amounts are recognized as cost of fuel, energy, and capacity on the income statement.

For derivatives designated as hedging contracts, TEP formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. Also, TEP formally documents hedging activity by transaction type and risk management strategy.

For derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. See Note 11 for additional information regarding derivative instruments.

NOTE 2. REGULATORY MATTERS

The ACC and the FERC each regulate portions of utility accounting practices and rates of TEP. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, transactions with affiliated parties, and other utility matters. The ACC also enacts other regulations and policies that can affect business decisions and accounting practices. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

2017 RATE ORDER

In February 2017, the ACC issued a rate order for new rates that took effect February 27, 2017. Provisions of the 2017 Rate Order include, but are not limited to:

- a non-fuel base rate increase of $81.5 million, which includes $15 million of operating costs related to the 50.5% undivided interest in Springerville Unit 1 purchased by TEP in September 2016;
- a 7.04% return on original cost rate base, which includes a cost of equity component of 9.75% and a cost of debt component of 4.32%;

- adoption of TEP's proposed depreciation and amortization rates, which include a reduction in the depreciable life for San Juan Unit 1; and
- approval of a request to apply excess depreciation reserves against the unrecovered NBV of San Juan Unit 2 and the coal handling facilities at Sundt due to early retirement.

The ACC deferred matters related to net metering and rate design for new DG customers to Phase 2, which is currently expected to be completed in the first half of 2018. TEP cannot predict the outcome of these proceedings.

FEDERAL TAX LEGISLATION - ACC DOCKET

In December 2017, the ACC opened a docket requesting that all regulated utilities submit proposals to address passing the ongoing benefits of the TCJA through to customers. TEP will actively participate in this docket and work with the ACC to reach an equitable solution. The Company cannot predict the outcome of these proceedings or how they may impact results of operations in the current or future years. See Note 12 for additional information regarding the TCJA.

COST RECOVERY MECHANISMS

TEP has received regulatory decisions that allow for more timely recovery of certain costs through the recovery mechanisms described below.

Purchased Power and Fuel Adjustment Clause

TEP's PPFAC rate is adjusted annually each April 1st and goes into effect for the subsequent 12-month period unless modified by the ACC. The PPFAC rate includes: (i) a forward component which is calculated by taking the difference between forecasted fuel and purchased power costs and the amount of those costs established in Retail Rates; and (ii) a true-up component that reconciles the difference between actual costs and those recovered in the preceding 12-month period. The PPFAC bank balance was over-collected by $9 million and $38 million as of December 31, 2017 and 2016, respectively.

In February 2017, the ACC approved a PPFAC credit to begin returning the over-collected PPFAC bank balance to customers. The table below presents TEP's PPFAC rates approved by the ACC:

Period	Cents per kWh
March 2017 through March 2018	(0.20)
May 2016 through February 2017	0.15
April 2015 through April 2016	0.68
October 2014 through March 2015	0.50

Renewable Energy Standard

The ACC’s RES requires Arizona regulated utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements by 2025, with DG accounting for 30% of the annual renewable energy requirement. Arizona utilities must file an annual RES implementation plan for review and approval by the ACC.

In January 2018, the ACC approved TEP's 2018 RES implementation plan with a budget amount of $54 million. The recovery funds the following: (i) the above market cost of renewable power purchases; (ii) previously awarded performance-based incentives for customer-installed DG; and (iii) various other program costs. TEP recognized $1 million of revenue in 2017 as a return on company-owned solar projects. TEP is no longer requesting recovery on company-owned solar projects through the RES mechanism and plans to request recovery of these types of costs through its rate case process. TEP suspended its rooftop solar program effective December 2016, but requested approval of a community solar program. The ACC is expected to consider this program in Phase 2 of TEP's rate case.

In 2017, the percentage of TEP's retail kWh sales attributable to the RES was approximately 10%, exceeding the overall 2017 RES requirement of 7%. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain DG RECs, which are used to demonstrate compliance with the DG requirement, the ACC approved a waiver of the 2017 and 2018 residential distributed

renewable energy requirement.
Energy Efficiency Standards
Under the EE Standards, the ACC requires electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. As of

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December 31, 2017, TEP's cumulative annual energy savings were approximately 14%.

TEP is required to implement cost-effective DSM programs to comply with the ACC's EE Standards. The EE Standards provide regulated utilities a DSM surcharge to recover from retail customers the costs to implement DSM programs, as well as an annual performance incentive. TEP records its annual DSM performance incentive for the prior calendar year in the first quarter of each year. TEP recorded $2 million in both 2017 and 2016, and $3 million in 2015 related to performance, included in Retail Revenues on the Consolidated Statements of Income.

In February 2016, the ACC approved TEP's 2016 energy efficiency implementation plan with a budget of approximately $22 million, which was partially offset by applying $8 million of previously recovered carryover funds. TEP has been approved to collect the remaining $14 million from retail customers through the DSM surcharge. Energy savings realized through the programs will count toward meeting the EE Standards and the associated lost revenue will be partially recovered through the LFCR mechanism.

In June 2016, TEP notified the ACC that it would not file a 2017 energy efficiency implementation plan and instead continue the 2016 level of recovery through the end of 2017. TEP reduced its costs and incentive levels for certain programs in order to minimize any potential under-collected DSM balance at the end of 2017.

In August 2017, TEP submitted its application for the 2018 energy efficiency implementation plan with a budget of $23 million and requested a waiver of the 2018 EE Standard. TEP expects to receive a decision on its 2018 energy efficiency implementation plan in the first half of 2018.

Lost Fixed Cost Recovery Mechanism

The LFCR mechanism provides for recovery of certain non-fuel costs that would go unrecovered due to reduced retail kWh sales as a result of implementing ACC-approved energy efficiency programs and customer-installed DG. TEP records a regulatory asset and recognizes LFCR revenues when the amounts are verifiable regardless of when the lost retail kWh sales occur. TEP is required to make an annual filing with the ACC requesting recovery of the LFCR revenues recognized in the prior year. The recovery is subject to a year-over-year cap of 2% of TEP's applicable retail revenues, as approved in the 2017 Rate Order.

TEP recorded regulatory assets and recognized LFCR revenues of $22 million in 2017, $18 million in 2016, and $12 million in 2015. LFCR revenues are included in Retail Revenues on the Consolidated Statements of Income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities recorded in the balance sheet are summarized in the table below:

($ in millions)	Remaining Recovery Period (years)	December 31, 2017	2016
Regulatory Assets			
Pension and Other Postretirement Benefits (Note 8)	Various	$126	$128
Early Generation Retirement Costs (1)	Various	84	—
Income Taxes Recoverable through Future Rates (2)	Various	40	29
Final Mine Reclamation and Retiree Healthcare Costs (3)	20	31	27
Lost Fixed Cost Recovery	1	29	23
Property Tax Deferrals (4)	1	24	23
Springerville Unit 1 Leasehold Improvements (5)	6	14	17
Sundt Coal Handling Facilities (6)	N/A	—	14
Other Regulatory Assets	Various	40	20
Total Regulatory Assets		388	281
Less Current Portion	1	94	56
Total Non-Current Regulatory Assets		$294	$225
Regulatory Liabilities			
Income Taxes Payable through Future Rates (2)	Various	$353	$3
Net Cost of Removal (7)	Various	180	270
Renewable Energy Standard	Various	44	32
Deferred Investment Tax Credits (8)	Various	14	23
Purchased Power and Fuel Adjustment Clause	1	9	38
Other Regulatory Liabilities	Various	5	11
Total Regulatory Liabilities		605	377
Less Current Portion	1	89	76
Total Non-Current Regulatory Liabilities		$516	$301

(1) Includes the NBV and other related costs of Navajo and Sundt Units 1 and 2 reclassified from Utility Plant, Net on the Consolidated Balance Sheets due to the planned early retirement of the facilities. As of December 31, 2017, Navajo and Sundt Units 1 and 2 are being fully recovered in base rates using various useful lives through 2030. See Note 3 for additional information related to the planned early retirement of Navajo and Sundt Units 1 and 2.

(2) Amortized over the life of the assets. The balances include changes related to the revaluation of tax assets and liabilities as a result of the TCJA. See Note 1 and Note 12 for additional information regarding income taxes.

(3) Represents costs associated with TEP’s jointly-owned facilities at San Juan, Four Corners, and Navajo. TEP recognizes these costs at future value and is permitted to fully recover these costs through the PPFAC mechanism. The majority of final mine reclamation costs are expected to occur through 2037.

(4) Property taxes are recorded as a regulatory asset based on historical ratemaking treatment allowing regulated utilities recovery of property taxes on a pay-as-you-go or cash basis. TEP records a liability to reflect the accrual for financial reporting purposes and an offsetting regulatory asset to reflect recovery for regulatory purposes. This asset is fully recovered in rates with a recovery period of approximately six months.

(5) Represents investments TEP made, which were previously recorded in Plant in Service on the Consolidated Balance Sheets, to ensure that the facilities continued to provide safe, reliable service to TEP's customers. TEP received ACC authorization to recover leasehold improvement costs at Springerville Unit 1 over a 10-year amortization period.

(6)

In June 2014, the EPA issued a final rule that required TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Sundt Unit 4 continued to use coal as a fuel source; or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source, and transferred the NBV of the Sundt Coal Handling Facilities to a regulatory asset. TEP applied excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) Represents an estimate of the future cost of retirement net of salvage value. These are amounts collected through revenue for transmission, distribution, generation plant, and general and intangible plant which are not yet expended. As a result of the 2017 Rate Order, $87 million was transferred from Net Cost of Removal to Accumulated Depreciation and Amortization to reflect the impact of the revised depreciation study on the estimated cost of removal.

(8) Represents federal energy credits generated after 2011 that are amortized over the tax life of the underlying asset.

Regulatory assets are either being collected or are expected to be collected through Retail Rates. With the exception of Early Generation Retirement Costs and Springerville Unit 1 Leasehold Improvements, TEP does not earn a return on regulatory assets. Regulatory liabilities represent items that TEP either expects to pay to customers through billing reductions in future periods or plans to use for the purpose for which they were collected from customers. With the exception of over-recovered PPFAC costs, TEP does not pay a return on regulatory liabilities.

FERC COMPLIANCE

In 2016, the FERC issued orders relating to certain late-filed TSAs, which resulted in TEP recording a liability and paying time-value refunds to the counterparties of these TSAs. In May 2017, the FERC informed TEP that the related investigation was closed. See Note 7 for additional information related to FERC compliance associated with these transmission contracts.

IMPACTS OF REGULATORY ACCOUNTING

If TEP determines that it no longer meets the criteria for continued application of regulatory accounting, TEP would be required to write off its regulatory assets and liabilities related to those operations not meeting the regulatory accounting requirements. Discontinuation of regulatory accounting could have a material impact on TEP's financial statements.

NOTE 3. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Plant in Service on the Consolidated Balance Sheets by major class:

($ in millions)	Annual Depreciation Rate (4)	Average Remaining Life in Years (4)	December 31, 2017	December 31, 2016
Plant in Service				
Generation Plant	3.19%	25	$2,548	$2,866
Transmission Plant	1.48%	32	1,001	1,024
Distribution Plant	1.56%	36	1,632	1,512
General Plant	5.89%	12	389	381
Intangible Plant, Software Costs, and Other (1)	Various	Various	207	185
Plant Held for Future Use	—	—	4	7
Total Plant in Service (2)			$5,781	$5,975
Utility Plant Under Capital Leases (3)			$85	$167

(1) Primarily represents computer software. Unamortized computer software costs were $59 million and $52 million as of December 31, 2017 and 2016, respectively. The amortization of computer software costs was $19 million in 2017, $17 million in 2016, and $14 million in 2015. Computer software is being amortized over its expected useful life ranging from three to five years for smaller application software and average remaining life of three years for large enterprise software.

(2) Includes plant acquisition adjustments of $(134) million and $(139) million as of December 31, 2017 and 2016, respectively.

(3)

In December 2017, TEP completed the purchase of an undivided ownership interest in the Springerville Common Facilities. See Note 6 for additional information regarding the Springerville leases.

(4) Represents a composite of the depreciation rates of assets within each major class of utility plant and is based on the 2015 depreciation study available for the major classes of Plant in Service. TEP implemented new depreciation rates effective March 1, 2017, as approved in the 2017 Rate Order.

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Utility Plant Under Capital Leases

All assets included in Utility Plant Under Capital Leases are used in generation operations and amortized over the primary lease term. The following table shows the amount of lease expense incurred for capital leases:

(in millions)	Years Ended December 31, 2017	2016	2015
Lease Expense			
Interest Expense included in:			
Interest Expense, Capital Leases	$3	$ 3	$ 4
Amortization of Capital Lease Assets included in:			
Operating Expenses, Fuel	—	—	2
Operating Expenses, Amortization	6	5	6
Total Lease Expense	$9	$ 8	$ 12

Springerville Acquisitions

In September 2016, TEP purchased an undivided interest in Springerville Unit 1. The purchase increased TEP's total ownership interest to 100%. In December 2017, TEP purchased an undivided interest in the Springerville Common Facilities. As of December 31, 2017, Utility Plant Under Capital Leases represented a 32.2% undivided interest in certain Springerville Common Facilities. See Note 6 for additional information regarding the Springerville capital lease purchases.

JOINTLY-OWNED FACILITIES

As of December 31, 2017, TEP was a participant in the following jointly-owned generation facilities and transmission systems:

(in millions)	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Book Value
San Juan Unit 1	50.0%	$ 274	$ 6	$ 83	$ 197
Four Corners Units 4 and 5	7.0%	113	54	79	88
Luna	33.3%	55	—	3	52
Gila River Unit 3	75.0%	203	3	60	146
Gila River Common Facilities	18.8%	25	—	8	17
Springerville Coal Handling Facilities	83.0%	202	—	81	121
Transmission Facilities	Various	483	5	247	241
Total		$ 1,355	$ 68	$ 561	$ 862

As participants in these jointly-owned facilities, TEP is responsible for its share of operating and capital costs for the above facilities. The Company accounts for its share of operating expenses and utility plant costs related to these facilities using proportionate consolidation.

RETIREMENTS

San Juan Generating Station

In October 2014, the EPA published a final rule approving a SIP covering BART requirements for San Juan, which included the closure of Units 2 and 3 by December 2017. TEP is a participant in San Juan Units 1 and 2. Given the closure of Units 2 and 3 and the desire of certain participants to exit their ownership in San Juan, PNM, TEP, and the other participants negotiated restructured ownership agreements which became effective upon the sale of San Juan Coal Company (SJCC) stock in January 2016. Under the new restructured ownership agreements, TEP and the other remaining participants have the option to exit their remaining ownership interests in San Juan as of June 30, 2022.

In 2017, TEP recorded the early retirement San Juan Unit 2 and applied excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order. The Consolidated Balance Sheets reflect a $224 million decrease in Plant in Service and Accumulated Depreciation and Amortization related to San Juan Unit 2. On December 20, 2017, San Juan Unit 2 was removed from service. See Note 2 for additional information regarding the 2017 Rate Order.

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Navajo Generating Station

In 2017, the Navajo Nation approved a land lease extension which allows TEP and the co-owners of Navajo to continue operations through December 2019 and begin decommissioning activities thereafter. TEP is currently recovering Navajo's capital and operating costs in base rates using a useful life of 2030. As a result of the planned early retirement of Navajo, $52 million of the facility's NBV and other related costs were reclassified from Utility Plant, Net to Regulatory Assets on the Consolidated Balance Sheets as of December 31, 2017. See Note 2 for additional information related to the planned early retirement of Navajo.

Sundt Generating Station

In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source to comply with the EPA rules and transferred the NBV of the coal handling facilities at Sundt to a regulatory asset. As approved in the 2017 Rate Order, TEP applied excess depreciation reserves against the regulatory asset as of December 31, 2017. See Note 2 for additional information regarding the 2017 Rate Order.

In 2017, TEP submitted an Air Quality Permit Application (Application) to the Pima County Department of Environmental Quality (PDEQ) related to a generation modernization project at Sundt that will add generation capacity in the form of RICE generators in 2019 and 2020. As part of the Application, TEP plans to early retire Sundt Units 1 and 2 by the end of 2020. TEP is currently recovering capital and operating costs for Sundt Units 1 and 2 in base rates using useful lives of 2028 and 2030, respectively. As a result of the planned early retirement, $31 million of the facilities' NBV was reclassified from Utility Plant, Net to Regulatory Assets on the Consolidated Balance Sheets as of December 31, 2017. See Note 2 for additional information related to the planned early retirement of Sundt Units 1 and 2.

ASSET RETIREMENT OBLIGATIONS

The accrual of AROs is primarily related to generation and PV assets and is included in Regulatory and Other Liabilities—Other on the Consolidated Balance Sheets. The following table reconciles the beginning and ending aggregate carrying amounts of ARO accruals on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2017	2016
Beginning of Period	$33	$32
Liabilities Incurred	3	—
Liabilities Settled	(1)	—
Regulatory Deferral/Accretion Expense	2	2
Revisions to the Present Value of Estimated Cash Flows [1]	9	(1)
End of Period	$46	$33

(1) Primarily related to changes in expected cost estimates and the acceleration of asset retirement dates of certain generation facilities.

NOTE 4. ACCOUNTS RECEIVABLE

The following table presents the components of Accounts Receivable, Net on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2017	2016
Customer	$81	$74
Due from Affiliates (Note 5)	7	9
Unbilled	39	34
Other	16	13
Allowance for Doubtful Accounts	(5)	(5)

Accounts Receivable, Net	$138	$125

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NOTE 5. RELATED PARTY TRANSACTIONS

TEP engages in various transactions with Fortis, UNS Energy, and its affiliated subsidiaries including UNS Electric, Inc. (UNS Electric), UNS Gas, Inc. (UNS Gas), and Southwest Energy Solutions, Inc. (SES) (collectively, UNS Energy Affiliates). These transactions include the sale and purchase of power and transmission services, common cost allocations, and the provision of corporate and other labor related services.

The following table presents the components of related party balances included in Accounts Receivable, Net and Accounts Payable on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2017	2016
Receivables from Related Parties		
UNS Electric	$ 5	$ 7
UNS Gas	2	2
Total Due from Related Parties	$ 7	$ 9
Payables to Related Parties		
SES	$ 3	$ 2
UNS Energy	1	—
Total Due to Related Parties	$ 4	$ 2

The following table presents the components of related party transactions included in the Consolidated Statements of Income:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Goods and Services Provided by TEP to Affiliates			
Transmission Revenues, UNS Electric (1)	$7	$ 7	$ 6
Wholesale Revenues, UNS Electric (1)	—	—	2
Control Area Services, UNS Electric (2)	3	2	2
Common Costs, UNS Energy Affiliates (3)	16	14	12
Corporate Services, Fortis Affiliates (4)	2	—	—
Goods and Services Provided by Affiliates to TEP			
Wholesale Revenues, UNS Electric (1)	—	1	1
Supplemental Workforce, SES (5)	15	14	16
Corporate Services, UNS Energy (6)	5	7	7
Corporate Services, UNS Energy Affiliates (7)	5	4	1

(1) TEP and UNS Electric sell power and transmission services to each other. Wholesale power is sold at prevailing market prices while transmission services are sold at FERC approved rates through the applicable Open Access Transmission Tariff.

(2) TEP charges UNS Electric for control area services under a FERC-approved Control Area Services Agreement.

(3) Common costs (information systems, facilities, etc.) are allocated on a cost-causative basis and recorded as revenue by TEP. The method of allocation is deemed reasonable by management and is reviewed by the ACC as part of the rate case process.

(4) TEP provides non-tariffed goods and services to Fortis affiliate companies at the higher of fully burdened cost or fair market value.

(5)

SES provides supplemental workforce and meter-reading services to TEP based on related party service agreements. The charges are based on cost of services performed and deemed reasonable by management.

(6) Costs for corporate services at UNS Energy are allocated to its subsidiaries using the Massachusetts Formula, an industry accepted method of allocating common costs to affiliated entities. TEP's allocation is approximately 82% of UNS Energy's allocated costs. Corporate Services, UNS Energy includes legal, audit, and Fortis Management fees. TEP's share of Fortis' management fees were $6 million in both 2017 and 2016, and $5 million in 2015.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) Costs for corporate services (e.g., finance, accounting, tax, legal, and information technology) and other labor services for UNS Energy Affiliates are directly assigned to the benefiting entity at a fully burdened cost when possible.

CONTRIBUTION FROM PARENT

UNS Energy made no equity contributions to TEP in 2017 or 2016. TEP received a contribution from UNS Energy of $180 million in 2015. The contributions were used to repay revolving credit loans, redeem bonds, purchase additional generation capacity, and provide additional liquidity to TEP.

DIVIDENDS PAID TO PARENT

TEP declared and paid $70 million in dividends to UNS Energy in 2017 and $50 million in both 2016 and 2015.

NOTE 6. DEBT, CREDIT FACILITY, AND CAPITAL LEASE OBLIGATIONS

DEBT

Long-term debt matures more than one year from the date of the financial statements. The following table presents the components of Long-Term Debt, Net on the Consolidated Balance Sheets:

			December 31,	
($ in millions)	Interest Rate	Maturity Date	2017	2016
Notes				
2011 Notes	5.15%	2021	$250	$250
2012 Notes	3.85%	2023	150	150
2014 Notes	5.00%	2044	150	150
2015 Notes	3.05%	2025	300	300
Tax-Exempt Local Furnishings Bonds				
2010 Pima A	5.25%	2040	100	100
2012 Pima A	4.50%	2030	16	16
2013 Pima A	4.00%	2029	91	91
2013 Apache A (1)	1.41%	2032	100	100
Tax-Exempt Pollution Control Bonds				
2009 Pima A	4.95%	2020	80	80
2009 Coconino A	5.13%	2032	15	15
2010 Coconino A (2)	1.76%	2032	37	37
2012 Apache A	4.50%	2030	177	177
Total Long-Term Debt (3)			1,466	1,466
Less Unamortized Discount and Debt Issuance Costs			12	13
Less Current Maturities of Long-Term Debt (1)			100	—
Total Long-Term Debt, Net			$1,354	$1,453

(1) The bonds are variable rate debt for which rates are reset monthly. The interest rate is calculated using a weighted average based on a percentage of an index equal to one-month LIBOR plus a credit spread. The bonds are subject to mandatory tender for purchase in November 2018, and were reclassified to Current Maturities of Long-Term Debt on the Consolidated Balance Sheets as of December 31, 2017.

(2) The bonds are variable rate debt for which rates are reset weekly. The interest rate is calculated using a weighted average and includes LOC fees and remarketing fees. The bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in February 2019.

(3) As of December 31, 2017, all of TEP's debt is unsecured, with the exception of the 2010 Coconino A variable rate bonds, which are backed by an LOC.

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DEBT ISSUANCES AND REDEMPTIONS

Fixed Rate Debt

In February 2015, TEP issued and sold $300 million aggregate principal amount of senior unsecured notes. TEP may redeem the notes prior to December 2024, with a make-whole premium plus accrued interest. On or after December 2024, TEP may redeem the notes at par plus accrued interest.

In January 2015, TEP purchased $130 million aggregate principal amount of unsecured tax-exempt IDRBs issued in June 2008 by the Industrial Development Authority (IDA) of Pima County, Arizona for the benefit of TEP. The bonds were not remarketed and were subsequently retired in September 2017.

Variable Rate Debt

In August 2015, TEP redeemed two series of variable rate tax-exempt bonds at par with an aggregate principal amount of $79 million prior to maturity. In September 2015, TEP terminated the associated LOCs issued under a revolving credit facility.

CREDIT FACILITY

In October 2015, TEP entered into an unsecured credit agreement which replaced its previous credit agreements. The credit facility included: (i) a borrowing capacity of $250 million in revolving credit commitments; (ii) an LOC facility with a sublimit of $50 million; and (iii) an original maturity date of October 2020 with a provision allowing TEP to request up to two one-year maturity extensions.

As permitted by the credit agreement, TEP requested and was granted two one-year extensions. The facility's new maturity date is October 2022.

Interest rates and fees under the credit facility are based on a pricing grid tied to TEP’s credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.00% for Eurodollar loans or ABR with no spread for ABR loans. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. As of December 31, 2017, TEP had $35 million borrowings outstanding included in Current Liabilities on the Consolidated Balance Sheets. As of February 14, 2018, there was $232 million available under the revolving credit commitments and LOC facilities.

TEP's previous credit agreements provided for a total of $270 million in revolving credit commitments, LOCs supporting variable-rate, tax-exempt bonds, and a $130 million term loan commitment, with original expiration dates of November 2016 and November 2015, respectively.

2010 REIMBURSEMENT AGREEMENT

In December 2010, a $37 million LOC was issued to support certain variable rate tax-exempt bonds pursuant to the 2010 Reimbursement Agreement. The LOC has an expiration date of February 2019. Fees are payable on the aggregate outstanding amount of the LOC at a rate of 0.75% per annum based on TEP's current credit ratings.

COVENANT COMPLIANCE

Certain of TEP's credit and long-term debt agreements contain restrictive covenants, including restrictions on additional indebtedness, liens to secure indebtedness, mergers, sales of assets, transactions with affiliates, and restricted payments. As of December 31, 2017, TEP was in compliance with the terms of its credit and long-term debt agreements.

CAPITAL LEASE OBLIGATIONS

The following table details Capital Lease Obligations on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2017	2016
Capital Lease Obligations	$ 39	$ 91
Less Current Obligations Under Capital Leases	11	52
Total Capital Lease Obligations, Non-Current	$ 28	$ 39

Springerville Unit 1 Capital Lease Purchases

In January 2015, upon expiration of the lease term, TEP purchased leased interests comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million, the appraised value. With the completion of the purchase, TEP owned 49.5% of Springerville Unit 1, or 192 MW of capacity.

In September 2016, TEP purchased the remaining undivided interest in Springerville Unit 1 for $85 million, bringing its total ownership of the assets to 100% and total generating capacity to 387 MW. See Note 7 for more information regarding the settlement agreement relating to Springerville Unit 1.

Springerville Coal Handling Facilities Lease Purchase

In April 2015, upon expiration of the lease term, TEP purchased an 86.7% undivided ownership interest in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million, bringing its total ownership of the assets to 100%. Upon purchase of the leased interest, TEP reduced Capital Lease Obligations on the Consolidated Balance Sheets for the purchase price.

In May 2015, SRP, the owner of Springerville Unit 4, purchased from TEP a 17.05% undivided interest in the Springerville Coal Handling Facilities for approximately $24 million.

Springerville Common Facilities Leases

As of December 31, 2017, the Springerville Common Facilities Leases include two leases with a total fixed price purchase options of $68 million and initial terms ending January 2021.

Under the two leases, TEP has options to: (i) renew the leases for periods of two or more years; or (ii) exercise the fixed price purchase options under these contracts. In addition, TEP entered into agreements with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that contain the following conditions if the Common Facilities Leases are not renewed: (i) TEP will exercise the purchase options under these contracts; (ii) SRP will be obligated to buy a 14% undivided interest in the facilities; and (iii) Tri-State will be obligated to either: (a) buy a 14% undivided interest in the facilities; or (b) continue to make payments to TEP for the use of these facilities.

In December 2017, TEP purchased a 17.8% undivided interest in the Springerville Common Facilities for $38 million, bringing its total ownership of the assets to 67.8%. Upon purchase of the leased interest, TEP reduced Current Lease Obligations on the Consolidated Balance Sheets by $36 million.

Springerville Common Facilities Lease Interest Rate Swap

TEP entered into an interest rate swap agreement in 2006 that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease debt. The swap has the effect of fixing the benchmark LIBOR rate on a portion of the amortizing principal balance. The swap matures in January 2020 with interest on the lease debt payable at a swapped rate of 5.77% plus an applicable margin per the lease agreement. The lease debt outstanding as of December 31, 2017 consisted of a notional amount of $18 million on which interest was fixed by the swap and a notional amount of $3 million of debt that was not hedged. The applicable margin was 1.88% as of December 31, 2017 and 2016.

TEP recorded the interest rate swap as a cash flow hedge for financial reporting purposes. See Cash Flow Hedges in Note 11 for additional information.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEBT MATURITIES

Long-term debt, including revolving credit facilities classified as long-term, and capital lease obligations mature on the following dates:

(in millions)	Long-Term Debt[1]	Capital Lease Obligations	Total Debt Maturities[2]
2018	$ 100	$ 11	$ 111
2019	37	11	48
2020	80	18	98
2021	250	—	250
2022	—	—	—
Total 2018 - 2022	467	40	507
Thereafter	999	—	999
Less: Imputed Interest	—	(1)	(1)
Total	$ 1,466	$ 39	$ 1,505

(1) $37 million of TEP's variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in February 2019. Although the variable rate bond matures in 2032, the above table reflects a redemption or repurchase of such bond in 2019 as though the LOC terminates without replacement upon expiration of the 2010 Reimbursement Agreement. TEP's 2013 tax-exempt variable rate IDRBs, which have an aggregate principal amount of $100 million and mature in 2032, are subject to mandatory tender for purchase in November 2018.

(2) Total long-term debt excludes $10 million of related unamortized debt issuance costs and $2 million of unamortized original issue discount.

NOTE 7. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As of December 31, 2017, TEP had the following firm, non-cancellable, minimum purchase obligations and operating leases:

(in millions)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel, Including Transportation	$82	$83	$73	$43	$ 24	$ 244	$549
Purchased Power	29	—	—	—	—	—	29
Transmission	19	19	8	4	1	8	59
Renewable Power Purchase Agreements	64	64	63	63	63	668	985
RES Performance-Based Incentives	8	8	7	7	7	46	83
Operating Leases [1]	1	1	1	1	1	3	8
Land Easements and Rights-of-Way	1	1	1	2	2	82	89
Total Purchase Commitments	$204	$176	$153	$120	$ 98	$ 1,051	$1,802

(1) Primarily represents leases for land, rail cars, and office facilities with varying terms, provisions, and expiration dates through 2036. TEP's operating lease expense totaled $1 million in 2017, $2 million in 2016, and $3 million in 2015.

Costs for Purchased Power, Transmission, and Fuel, Including Transportation, are recoverable from customers through the PPFAC mechanism. A portion of the costs of PPAs are recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. PBIs costs are recoverable through the RES tariff. See Note 2 for information on ACC approved cost recovery mechanisms.

Fuel, Including Transportation

TEP has long-term agreements for the purchase and delivery of coal with various expiration dates between 2020 and 2031. Amounts paid under these contracts depend on actual quantities purchased and delivered. Some of these agreements include price adjustment components that will affect future costs.

TEP has firm transportation agreements with capacity sufficient to meet its load requirements. These agreements expire in various years between 2018 and 2040. In January 2018, TEP entered into a transportation agreement with EPNG extending the expiration date of the existing agreement from April 2018 to April 2023. Estimated future payments not included in the table above are: $4 million in 2018; $5 million in 2019 through 2022; and $1 million through the end of the contract.

Purchased Power

TEP has contracts with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. In general, these contracts provide for capacity and energy payments based on actual power taken under the contracts with various expiration dates through the fourth quarter of 2018. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table above are based on projected market prices as of December 31, 2017.

Transmission

TEP has agreements with other utilities to purchase transmission services over lines that are part of the Western Interconnection, a regional grid in the United States. These agreements expire in various years between 2019 and 2030.

Renewable Power Purchase Agreements

TEP enters into long-term renewable PPAs which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under the agreements if power is not delivered, estimated future payments are included in the table above. These agreements expire in various years between 2027 and 2036.

RES Performance-Based Incentives

TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed PBIs and are paid in contractually agreed-upon intervals (usually quarterly) based on metered renewable energy production. These agreements expire in various years between 2020 and 2034.

Land Easements and Rights-of-Way

Land Easements and Rights-of-Way have varying terms and provisions, and various expiration dates through 2054. In November 2017, the Navajo Nation approved an extension for the use of their land. The extension, signed by TEP and the co-owners of Navajo, commences in December 2019 and ends in December 2054. The Navajo Nation has until December 2018 to select one of five different rental payments options provided for in the extension. The table above includes TEP's 7.5% ownership share of the option which, in management's opinion, is most probable to occur. The total obligation estimated under this option is $8 million commencing in 2019 through 2053. Under the remaining payment options, TEP's share of estimated total payment obligation ranges from $3 million to $8 million with various payment schedules with dates ranging from 2019 through 2053.

CONTINGENCIES

Legal Matters

TEP is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. TEP believes such normal and routine litigation will not have a material impact on its consolidated financial results. TEP is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties, and other costs in substantial amounts on TEP and are disclosed below.

Claims Related to Springerville Generating Station Unit 1

In February 2016, TEP entered into an agreement with the Third-Party Owners for the settlement and release of asserted claims and the purchase and sale of beneficial interests in Springerville Unit 1 (Agreement). In September 2016, TEP received FERC authorization to complete the transactions contemplated in the Agreement. In accordance with the Agreement, TEP purchased the Third-Party Owners’ undivided interest in Springerville Unit 1 for $85 million. As also provided for in the Agreement, TEP received $12.5 million from the Third-Party Owners in full satisfaction of all previously unreimbursed operating costs, which TEP recorded in Operating Revenues—Other on the Consolidated Statements of Income. Following the purchase, all outstanding disputes, pending litigation, and arbitration proceedings between TEP and the Third-Party Owners were dismissed with prejudice.

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Claims Related to San Juan Generating Station

WildEarth Guardians

In 2013, WildEarth Guardians (WEG) filed a Petition for Review in the U.S. District Court for the District of Colorado against the Office of Surface Mining (OSM) challenging several unrelated mining plan modification approvals, including two issued in 2008 related to SJCC 's San Juan mine. The petition alleges various National Environmental Policy Act (NEPA) violations against the OSM, including: (i) failure to provide requisite public notice and participation; and (ii) failure to analyze certain environmental impacts. WEG's petition seeks various forms of relief, including voiding and remanding the various mining modification approvals, enjoining the federal defendants from re-issuing the approvals until they can demonstrate compliance with the NEPA, and enjoining operations at the affected mines. SJCC intervened in this matter and was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now pending. In July 2016, the federal defendants filed a motion asking that the matter be voluntarily remanded to the OSM so the OSM may prepare a new environmental impact statement (EIS) under the NEPA regarding the impacts of the San Juan Mine mining plan approval. In August 2016, the court issued an order granting the motion for remand to conduct further environmental analysis and complete an EIS by August 31, 2019. The order provides that: (i) the OSM's decision approving the mining plan will remain in effect during this process; or (ii) if the EIS is not completed by August 31, 2019, then the approved mine plan will immediately be vacated, absent further court order. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Claims Related to Four Corners Generating Station

Endangered Species Act

On April 20, 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Arizona against the OSM and other federal agencies under the Endangered Species Act (ESA) alleging that the OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the U.S. Department of the Interior's review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. This review process also required separate environmental impact evaluations under the NEPA and culminated in the issuance of a Record of Decision justifying the agency action extending the life of Four Corners and the adjacent Navajo Mine. In addition, the lawsuit alleges that these federal agencies violated both the ESA and the NEPA in providing the federal approvals necessary to extend operations at Four Corners and Navajo Mine past July 6, 2016. The lawsuit seeks various forms of relief, including a finding that the federal defendants violated the ESA and the NEPA by issuing the Record of Decision, setting aside and remanding the Biological Opinion and Record of Decision, and enjoining the federal defendants from authorizing any elements of the Four Corners and Navajo Mine pending compliance with NEPA. In July 2016, the defendants answered the complaint and APS, the operator of Four Corners, filed a motion to intervene in this matter. APS' motion was granted in August 2016. In September 2016, Navajo Transitional Energy Company, LLC (NTEC), the company that owns the Navajo Mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. In September 2017, the court granted NTEC's motion to dismiss and dismissed the case with prejudice. In November 2017, the plaintiffs appealed to the U.S. Court of Appeals for the Ninth Circuit the District Court's decision to dismiss the case. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Mine Reclamation at Generating Facilities Not Operated by TEP

TEP pays ongoing mine reclamation costs related to coal mines that supply generation facilities in which TEP has an ownership interest but does not operate. TEP is also liable for a portion of final mine reclamation costs upon closure of the mines servicing Navajo, San Juan, and Four Corners. TEP's share of reclamation costs at all three mines is expected to be $61 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The Consolidated Balance Sheets reflect a total liability related to reclamation of $34 million and $26 million as of December 31, 2017 and 2016, respectively.

Amounts recorded for final mine reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements.

TEP's PPFAC allows the Company to pass through final mine reclamation costs, as a component of fuel costs, to retail customers. Therefore, TEP classifies these costs as a regulatory asset by increasing the regulatory asset and the reclamation liability over the remaining life of the coal supply agreements and recovers the regulatory asset through the PPFAC as final mine reclamation costs are paid to the coal suppliers.

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FERC Compliance

In 2015 and 2016, TEP self-reported to the FERC Office of Enforcement (OE) that the Company had not timely filed certain FERC-jurisdictional agreements. TEP conducted comprehensive internal reviews of its compliance with the FERC filing requirements (Compliance Reviews), and made compliance filings with the FERC Office of Energy Market Regulation. This included the filing of several TSAs entered into between 2003 and 2015 that contained certain deviations from TEP’s standard service agreement form.

In 2016, as a result of the FERC Refund Orders and ongoing discussions with the OE, TEP recorded a liability for the time-value refunds with a corresponding offset in revenues on its financial statements in 2016. In 2016, Wholesale Revenues on the Consolidated Statements of Income reflected $22 million, and, as of December 31, 2016, Current Liabilities—Other on the Consolidated Balance Sheets reflected $5 million related to the time-value refunds.

In June 2016, to preserve its rights, TEP petitioned the U.S. Court of Appeals for the District of Columbia Circuit to review the FERC Refund Orders. In January 2017, TEP and one of the TSA counterparties entered into a settlement agreement regarding the FERC Refund Orders. In accordance with the agreement, the counterparty paid TEP $8 million, which TEP recorded in Other Income on the Consolidated Statements of Income and dismissed the appeal with prejudice in January 2017.

In May 2017, the FERC informed TEP that: (i) no further enforcement actions were necessary regarding the late-filed TSAs; and (ii) the related investigation was closed. As management no longer believed a loss was probable, TEP reversed the $5 million remaining balance related to potential time-value refunds in Current Liabilities—Other on the Consolidated Balance Sheets, offsetting Wholesale Revenues on the Consolidated Statements of Income.

Performance Guarantees

TEP has joint participation agreements with participants at Navajo, San Juan, Four Corners, and Luna. The participants in each of the generation facilities, including TEP, have guaranteed certain performance obligations. Specifically, in the event of payment default, each non-defaulting participant has agreed to bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. With the exception of Four Corners, there is no maximum potential amount of future payments TEP could be required to make under the guarantees. The maximum potential amount of future payments is $250 million at Four Corners. As of December 31, 2017, there have been no such payment defaults under any of the participation agreements. The Navajo participation agreement expires in 2019, San Juan in 2022, Four Corners in 2041, and Luna in 2046.

NOTE 8. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

TEP has three noncontributory, defined benefit pension plans. Benefits are based on years of service and average compensation. Two of the plans cover the majority of TEP's employees. The Company funds those plans by contributing at least the minimum amount required under Internal Revenue Service (IRS) regulations. TEP also maintains a SERP for executive management.

OTHER POSTRETIREMENT BENEFITS PLAN

TEP provides limited healthcare and life insurance benefits for retirees. Active TEP employees may become eligible for these benefits if they reach retirement age while working for TEP or an affiliate.

TEP funds its other postretirement benefits for classified employees through a VEBA. TEP contributed $3 million in 2017, $2 million in 2016, and $4 million in 2015 to the VEBA. Other postretirement benefits for unclassified employees are self-funded.

REGULATORY RECOVERY

TEP records changes in non-SERP pension and other postretirement defined benefit plans, not yet reflected in net periodic benefit cost, as a regulatory asset, as such amounts are probable of future recovery in the rates charged to retail customers. Changes in the SERP obligation, not yet reflected in net periodic benefit cost, are recorded in Other

Comprehensive Income since SERP expense is not currently recoverable in rates.

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The following table presents pension and other postretirement benefit amounts (excluding tax balances) included on the Consolidated Balance Sheets:

	Pension Benefits		Other Postretirement Benefits	
	December 31,			
(in millions)	2017	2016	2017	2016
Regulatory Assets	$121	$123	$5	$5
Accrued Employee Expenses	(1)	(1)	(2)	(2)
Pension and Other Postretirement Benefits	(71)	(69)	(63)	(63)
Accumulated Other Comprehensive Loss, SERP	9	6	—	—
Net Amount Recognized	$58	$59	$(60)	$(60)

OBLIGATIONS AND FUNDED STATUS

The Company measured the actuarial present values of all defined benefit pension and other postretirement benefit obligations as of December 31, 2017 and 2016. The table below presents the status of all of TEP's pension and other postretirement benefit plans. All plans have projected benefit obligations in excess of the fair value of plan assets for each period presented:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
(in millions)	2017	2016	2017	2016
Change in Benefit Obligation				
Beginning of Period	$424	$394	$79	$78
Actuarial Loss	42	20	1	—
Interest Cost	15	15	2	2
Service Cost	13	12	4	4
Benefits Paid	(19)	(17)	(4)	(5)
End of Period	475	424	82	79
Change in Fair Value of Plan Assets				
Beginning of Period	354	336	14	13
Actual Return on Plan Assets	59	27	2	1
Benefits Paid	(19)	(17)	(4)	(5)
Employer Contributions [(1)]	9	8	5	5
End of Period	403	354	17	14
Funded Status at End of Period	$(72)	$(70)	$(65)	$(65)

(1) TEP expects to contribute $11 million to the pension plans in 2018.

The following table provides the components of TEP's regulatory assets and accumulated other comprehensive loss that have not been recognized as components of net periodic benefit cost as of the dates presented:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
(in millions)	2017	2016	2017	2016
Net Loss	$129	$128	$5	$6
Prior Service Cost (Benefit)	1	—	(1)	(1)

The accumulated benefit obligation aggregated for all pension plans is $428 million and $384 million as of December 31, 2017 and 2016, respectively. Two of the pension plans had accumulated benefit obligations in excess of plan assets as of December 31, 2017, compared to three as of December 31, 2016, as a result of market gains on plan assets in 2017. The following table

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includes information for the pension plans with accumulated benefit obligations in excess of pension plan assets:

	December 31,	
(in millions)	2017	2016
Accumulated Benefit Obligation	$237	$384
Fair Value of Plan Assets	206	354

Beginning in 2016, the Company elected to measure service and interest costs by applying the specific spot rates along the yield curve to the plans' liability cash flows. Prior to 2016, the Company measured service and interest costs for pension and other postretirement benefits utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. TEP believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of its plan obligations nor the funded status. TEP accounted for this change as a change in accounting estimate, and accordingly, accounted for it on a prospective basis. Net periodic benefit plan cost includes the following components:

	Pension Benefits			Other Postretirement Benefits		
	Years Ended December 31,					
(in millions)	2017	2016	2015	2017	2016	2015
Service Cost	$13	$12	$12	$4	$4	$4
Interest Cost	15	15	17	2	2	3
Expected Return on Plan Assets	(25)	(23)	(23)	(1)	(1)	(1)
Amortization of Net Loss	8	7	7	—	—	—
Net Periodic Benefit Cost	$11	$11	$13	$5	$5	$6

Approximately 18% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in income.

The changes in plan assets and benefit obligations recognized as regulatory assets or in AOCI were as follows:

	Pension Benefits						Other Postretirement Benefits		
	Regulatory Asset			AOCI			Regulatory Asset		
(in millions)	2017	2016	2015	2017	2016	2015	2017	2016	2015
Current Year Actuarial (Gain) Loss	$5	$15	$5	$3	$1	$—	$(1)	$—	$(4)
Amortization of Net Loss	(7)	(7)	(7)	—	—	—	—	—	—
Total Recognized (Gain) Loss	$(2)	$8	$(2)	$3	$1	$—	$(1)	$—	$(4)

For all pension plans, TEP amortizes prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plans. Estimated amortization from regulatory assets into net periodic benefit cost in 2018 includes the following:

(in millions)	Pension Benefits	Other Postretirement Benefits
Net Loss	$ 7	$ —

Net periodic benefit cost is subject to various assumptions and determinations, such as the discount rate, the rate of compensation increase, and the expected return on plan assets. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as net periodic benefit cost.

TEP uses a combination of sources in selecting the expected long-term rate-of-return-on-assets assumption, including an investment return model. The model used provides a "best-estimate" range over 20 years from the 25th percentile to the 75th percentile. The model, used as a guideline for selecting the overall rate-of-return-on-assets assumption, is based on forward-looking return expectations only. The above method is used for all asset classes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table includes the weighted average assumptions used to determine benefit obligations:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	2017	2016
Discount Rate	3.7%	4.2%	3.6%	4.0%
Rate of Compensation Increase	2.8%	2.8%	N/A	N/A

The following table includes the weighted average assumptions used to determine net periodic benefit costs:

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	2017	2016	2015
Discount Rate, Service Cost	4.4%	4.8%	4.2%	4.3%	4.6%	3.9%
Discount Rate, Interest Cost	3.7%	3.9%	4.2%	3.3%	3.4%	3.9%
Rate of Compensation Increase	2.8%	3.0%	3.0%	N/A	N/A	N/A
Expected Return on Plan Assets	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%

Healthcare cost trend rates are assumed to decrease gradually from next year to the year the ultimate rate is reached:

	December 31,	
	2017	2016
Next Year	7.6%	7.6%
Ultimate Rate Assumed	4.5%	4.5%
Year Ultimate Rate is Reached	2036	2037

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

	One-Percentage-Point Increase	One-Percentage-Point Decrease
(in millions)	December 31, 2017	
Increase (Decrease) on Total Service and Interest Cost Components	$ 1	$ (1)
Increase (Decrease) on Other Postretirement Benefits Obligation	7	(6)

PENSION PLAN AND OTHER POSTRETIREMENT BENEFIT ASSETS

TEP calculates the fair value of plan assets on December 31, the measurement date. Asset allocations, by asset category, on the measurement date were as follows:

	Pension		Other Postretirement Benefits	
	2017	2016	2017	2016
Asset Category				
Equity Securities	46 %	49 %	63 %	60 %
Fixed Income Securities	45 %	41 %	35 %	35 %
Real Estate	7 %	8 %	— %	2 %
Other	2 %	2 %	2 %	3 %
Total	100 %	100 %	100 %	100 %

As of December 31, 2017, the fair value of VEBA trust assets was $17 million, of which $6 million were fixed income investments and $11 million were equities. As of December 31, 2016, the fair value of VEBA trust assets was

$14 million, of which $5 million were fixed income investments and $9 million were equities. The VEBA trust assets are primarily Level 2. There are no Level 3 assets in the VEBA trust.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables present the fair value measurements of pension plan assets by level within the fair value hierarchy:

	Level 1	Level 2	Level 3	Total
(in millions)	December 31, 2017			
Asset Category				
Cash Equivalents	$1	$—	$ —	$1
Equity Securities:				
United States Large Cap	—	66	—	66
United States Small Cap	—	19	—	19
Non-United States	—	72	—	72
Global	—	30	—	30
Fixed Income	—	179	—	179
Real Estate	—	9	21	30
Private Equity	—	—	6	6
Total	$1	$375	$ 27	$403

(in millions)	December 31, 2016			
Asset Category				
Cash Equivalents	$1	$—	$ —	$1
Equity Securities:				
United States Large Cap	—	61	—	61
United States Small Cap	—	18	—	18
Non-United States	—	67	—	67
Global	—	28	—	28
Fixed Income	—	144	—	144
Real Estate	—	9	19	28
Private Equity	—	—	7	7
Total	$1	$327	$ 26	$354

- Level 1 cash equivalents are based on observable market prices and are comprised of the fair value of commercial paper, money market funds, and certificates of deposit.
- Level 2 investments comprise amounts held in commingled equity funds, United States bond funds, and real estate funds. Valuations are based on active market quoted prices for assets held by each respective fund.
- Level 3 real estate investments values are generally determined by appraisals conducted in accordance with accepted appraisal guidelines, including consideration of projected income and expenses of the property as well as recent sales of similar properties.
- Level 3 private equity funds are classified as funds-of-funds. They are valued based on individual fund manager valuation models.

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The following table presents a reconciliation of changes in the fair value of pension plan assets classified as Level 3 in the fair value hierarchy. There were no transfers in or out of Level 3.

(in millions)	Private Equity	Real Estate	Total
Balance as of December 31, 2015	$ 7	$ 18	$ 25
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	1	2
Purchases, Sales, and Settlements	(1)	—	(1)
Balance as of December 31, 2016	7	19	26
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	(2)	—	(2)
Balance as of December 31, 2017	$ 6	$ 21	$ 27

Pension Plan Investments

Investment Goals

Asset allocation is the principal method for achieving each pension plan's investment objectives while maintaining appropriate levels of risk. TEP considers the projected impact on benefit security of any proposed changes to the current asset allocation policy. The expected long-term returns and implications for pension plan sponsor funding are reviewed in selecting policies to ensure that current asset pools are projected to be adequate to meet the expected liabilities of the pension plans. TEP expects to use asset allocation policies weighted most heavily to equity and fixed income funds, while maintaining some exposure to real estate and opportunistic funds. Within the fixed income allocation, long-duration funds may be used to partially hedge interest rate risk.

Risk Management

TEP recognizes the difficulty of achieving investment objectives in light of the uncertainties and complexities of the investment markets. The Company recognizes some risk must be assumed to achieve a pension plan's long-term investment objectives. In establishing risk tolerances, the following factors affecting risk tolerance and risk objectives will be considered: (i) plan status; (ii) plan sponsor financial status and profitability; (iii) plan features; and (iv) workforce characteristics. TEP determined that the pension plans can tolerate some interim fluctuations in market value and rates of return in order to achieve long-term objectives. TEP tracks each pension plan's portfolio relative to the benchmark through quarterly investment reviews. The reviews consist of a performance and risk assessment of all investment categories and on the portfolio as a whole. Investment managers for the pension plan may use derivative financial instruments for risk management purposes or as part of their investment strategy. Currency hedges may also be used for defensive purposes.

Relationship between Plan Assets and Benefit Obligations

The overall health of each plan will be monitored by comparing the value of plan obligations (both Accumulated Benefit Obligation and Projected Benefit Obligation) against the fair value of assets and tracking the changes in each. The frequency of this monitoring will depend on the availability of plan data, but will be no less frequent than annually via actuarial valuation.

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Target Allocation Percentages

The current target allocation percentages for the major asset categories of the plan follow. Each plan allows a variance of +/- 2% from targets before funds are automatically rebalanced.

	Pension	Other Postretirement Benefits
	December 31, 2017	
Cash/Treasury Bills	—%	2%
Equity Securities:		
United States Large Cap	16%	39%
United States Small Cap	5%	5%
Non-United States Developed	14%	7%
Non-United States Emerging	4%	9%
Global Equity	4%	—%
Global Infrastructure	3%	—%
Fixed Income	45%	38%
Real Estate	8%	—%
Private Equity	1%	—%
Total	100%	100%

Pension Fund Descriptions

For each type of asset category selected by the Pension Committee, TEP's investment consultant assembles a group of third-party fund managers and allocates a portion of the total investment to each fund manager. In the case of the private equity fund, TEP's investment consultant directs investments to a private equity manager that invests in third-parties' funds.

ESTIMATED FUTURE BENEFIT PAYMENTS

TEP expects the following benefit payments to be made by the plans, which reflect future service, as appropriate.

(in millions)	2018	2019	2020	2021	2022	2023-2027
Pension Benefits	$ 21	$ 22	$ 23	$ 24	$ 25	$ 137
Other Postretirement Benefits	5	5	5	6	6	30

DEFINED CONTRIBUTION PLAN

TEP offers a defined contribution savings plan to all eligible employees. The Internal Revenue Code identifies the plan as a qualified 401(k) plan. Participants direct the investment of contributions to certain funds in their account. The Company matches part of a participant's contributions to the plan. TEP made matching contributions to the plan of $6 million in 2017, and $5 million in both 2016 and 2015.

NOTE 9. SHARE-BASED COMPENSATION

2015 SHARE UNIT PLAN

The Human Resources and Governance Committee (Committee) of UNS Energy approved and UNS Energy's Board of Directors ratified the 2015 Share Unit Plan (Plan) effective January 2015. Under the Plan, key employees, including executive officers of UNS Energy and its subsidiaries, may be granted long-term incentive awards of performance-based share units (PSUs) and time-based restricted share units (RSUs) annually. Each PSU and RSU granted is valued based on one share of Fortis common stock traded on the Toronto Stock Exchange, converted to U.S. dollars. UNS Energy allocates the obligation and expense for this plan to its subsidiaries based on the Massachusetts Formula.

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The following table represents PSUs and RSUs awarded by UNS Energy:

	2017	2016	2015
PSUs	68,126	66,974	47,776
RSUs	34,063	33,488	23,888

The awards are classified as liability awards based on the cash settlement feature. Liability awards are measured at their fair value at the end of each reporting period and will fluctuate based on the price of Fortis' common stock as well as the level of achievement of the financial performance criteria. The awards are payable on the third anniversary of the grant date. TEP's allocated share of probable payout was $9 million and $4 million as of December 31, 2017 and 2016, respectively.

TEP's allocated portion of compensation expense is recognized in Operations and Maintenance Expense on the Consolidated Statements of Income. Compensation expense associated with unvested PSUs and RSUs is recognized on a straight-line basis over the minimum required service period in an amount equal to the fair value on the measurement date or each reporting period. TEP recorded $4 million in 2017, $2 million in 2016, and $1 million in 2015 based on its share of UNS Energy's compensation expense.

NOTE 10. SUPPLEMENTAL CASH FLOW INFORMATION

CASH TRANSACTIONS

	Years Ended December 31,		
(in millions)	2017	2016	2015
Interest, Net of Amounts Capitalized	$61	$ 61	$ 65
Income Taxes [(1)]	—	—	—

(1) TEP did not pay federal or state income taxes due to net operating loss carryforwards offsetting taxable income.

NON-CASH TRANSACTIONS

Other significant non-cash investing and financing activities that affected recognized assets and liabilities but did not result in cash receipts or payments were as follows:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Net Cost of Removal Increase (Decrease) [(1)]	$(88)	$ 8	$ 1
Accrued Capital Expenditures	24	29	28
Commitment to Purchase Capital Lease Interests	—	36	—
Asset Retirement Obligations Increase (Decrease) [(2)]	10	(1)	3

(1) Represents an accrual for future cost of retirement net of salvage values that does not impact earnings. In the 2017 Rate Order, the ACC authorized a new depreciation study for TEP modifying its depreciation reserves and rates. See Note 2 for additional information.

(2) The non-cash additions to AROs and related capitalized assets represent a revision of estimated asset retirement cost due to changes in timing and amount of the expected future AROs.

NOTE 11. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

TEP categorizes financial instruments into the three-level hierarchy based on inputs used to determine the fair value. Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in an active market. Level 2 inputs include quoted prices for similar assets or liabilities, quoted prices in non-active markets, and pricing models whose inputs are observable, directly or indirectly. Level 3 inputs are unobservable and supported by little or no market activity. Transfers between levels are recorded at the end of a reporting period. There were no transfers between levels in the periods presented.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS

The following tables present, by level within the fair value hierarchy, TEP's assets and liabilities accounted for at fair value on a recurring basis classified in their entirety based on the lowest level of input that is significant to the fair value measurement:

	Level 1	Level 2	Level 3	Total
(in millions)	December 31, 2017			
Assets				
Cash Equivalents[1]	$30	$ —	$ —	$30
Restricted Cash[1]	12	—	—	12
Energy Derivative Contracts, Regulatory Recovery[2]	—	9	—	9
Energy Derivative Contracts, No Regulatory Recovery[2]	—	—	3	3
Total Assets	42	9	3	54
Liabilities				
Energy Derivative Contracts, Regulatory Recovery[2]	—	(26)	—	(26)
Energy Derivative Contracts, No Regulatory Recovery[2]	—	—	(1)	(1)
Interest Rate Swap[3]	—	(1)	—	(1)
Total Liabilities	—	(27)	(1)	(28)
Total Assets (Liabilities), Net	$42	$ (18)	$ 2	$26
(in millions)	December 31, 2016			
Assets				
Cash Equivalents[1]	$23	$—	$—	$23
Restricted Cash[1]	7	—	—	7
Energy Derivative Contracts, Regulatory Recovery[2]	—	3	—	3
Energy Derivative Contracts, No Regulatory Recovery[2]	—	—	2	2
Total Assets	30	3	2	35
Liabilities				
Energy Derivative Contracts, Regulatory Recovery[2]	—	(2)	(1)	(3)
Interest Rate Swap[3]	—	(2)	—	(2)
Total Liabilities	—	(4)	(1)	(5)
Total Assets (Liabilities), Net	$30	$(1)	$1	$30

(1) Cash Equivalents and Restricted Cash represent amounts held in money market funds and certificates of deposit valued at cost, including interest, which approximates fair market value. Cash Equivalents are included in Cash and Cash Equivalents on the Consolidated Balance Sheets. Restricted Cash is included in Investments and Other Property and in Current Assets—Other on the Consolidated Balance Sheets.

(2) Energy Derivative Contracts include gas swap agreements (Level 2) and forward purchased power and sales contracts (Level 3) entered into to reduce exposure to energy price risk. These contracts are included in Derivative Instruments on the Consolidated Balance Sheets. The valuation techniques are described below.

(3) The Interest Rate Swap is valued using an income valuation approach based on the 6-month LIBOR and is included in Derivative Instruments on the Consolidated Balance Sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All energy derivative contracts are subject to legally enforceable master netting arrangements to mitigate credit risk. TEP presents derivatives on a gross basis in the balance sheet. The tables below present the potential offset of counterparty netting and cash collateral.

	Gross Amount Recognized in the Balance Sheets	Gross Amount Not Offset in the Balance Sheets: Counterparty Netting of Energy Contracts	Gross Amount Not Offset in the Balance Sheets: Cash Collateral Received/Posted	Net Amount
(in millions)	December 31, 2017			
Derivative Assets				
Energy Derivative Contracts	$12	$ 10	$ —	$ 2
Derivative Liabilities				
Energy Derivative Contracts	(27)	(10)	—	(17)
Interest Rate Swap	(1)	—	—	(1)
(in millions)	December 31, 2016			
Derivative Assets				
Energy Derivative Contracts	$5	$2	$—	$3
Derivative Liabilities				
Energy Derivative Contracts	(3)	(2)	—	(1)
Interest Rate Swap	(2)	—	—	(2)

DERIVATIVE INSTRUMENTS

TEP enters into various derivative and non-derivative contracts to reduce exposure to energy price risk associated with its natural gas and purchased power requirements. The objectives for entering into such contracts include: (i) creating price stability; (ii) meeting load and reserve requirements; and (iii) reducing exposure to price volatility that may result from delayed recovery under the PPFAC mechanism.

The Company primarily applies the market approach for recurring fair value measurements. When TEP has observable inputs for substantially the full term of the asset or liability or uses quoted prices in an inactive market, it categorizes the instrument in Level 2. TEP categorizes derivatives in Level 3 when an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers is used.

For both purchased power and natural gas prices, TEP obtains quotes from brokers, major market participants, exchanges, or industry publications and relies on its own price experience from active transactions in the market. The Company primarily uses one set of quotations each for purchased power and natural gas and then validates those prices using other sources. TEP believes that the market information provided is reflective of market conditions as of the time and date indicated.

Published prices for energy derivative contracts may not be available due to the nature of contract delivery terms such as non-standard time blocks and non-standard delivery points. In these cases, TEP applies adjustments based on historical price curve relationships, transmission costs, and line losses.

TEP also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

The inputs and the Company's assessments of the significance of a particular input to the fair value measurements require judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. TEP reviews the assumptions underlying its price curves monthly.

Cash Flow Hedges

To mitigate the exposure to volatility in variable interest rates on debt, TEP has an interest rate swap agreement that expires in January 2020. TEP had a purchased power swap to hedge the cash flow risk associated with a long-term power supply agreement which expired in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities are reported in the statement of comprehensive income. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $1 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Realized losses from cash flow hedges are shown in the following table:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Capital Lease Interest Expense	$1	$ 1	$ 2
Purchased Power	—	—	1

As of December 31, 2017, the total notional amount of the interest rate swap was $18 million.

Energy Derivative Contracts, Regulatory Recovery

TEP records unrealized gains and losses on energy purchase contracts that are recoverable through the PPFAC mechanism on the balance sheet as a regulatory asset or a regulatory liability rather than reporting the transaction in the income statement or in the statement of other comprehensive income, as shown in the following table:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$(18)	$ 12	$ 6

Energy Derivative Contracts, No Regulatory Recovery

TEP enters into certain contracts that qualify as derivatives, but do not meet the regulatory recovery criteria. The Company records unrealized gains and losses for these contracts in the income statement unless a normal purchase or normal sale election is made. For contracts that meet the trading definition, as defined in the PPFAC plan of administration, TEP must share 10% of any realized gains with retail customers through the PPFAC mechanism.

Derivative Volumes

As of December 31, 2017, TEP has energy contracts that will settle on various expiration dates through 2029. The volumes associated with the energy contracts were as follows:

	December 31,	
	2017	2016
Power Contracts GWh	2,589	2,610
Gas Contracts BBtu [(1)]	137,952	12,355

(1) Increase in volume of gas contracts is a result of the planned early retirement of certain coal-fired generation. To reduce exposure to energy price risk associated with natural gas, the Company entered into longer term gas contracts increasing its overall volume outstanding in 2017. See Note 3 for additional information related to the planned early retirement of coal-fired generation.

Level 3 Fair Value Measurements

The following tables provide quantitative information regarding significant unobservable inputs in TEP's Level 3 fair value measurements:

	Valuation Approach	Fair Value of Assets	Fair Value of Liabilities	Unobservable Inputs	Range of Unobservable Input	
(in millions)	December 31, 2017					
Forward Power Contracts	Market approach	$ 3	$ (1)	Market price per MWh	$ 17.65	$ 34.60
(in millions)	December 31, 2016					
Forward Power Contracts	Market approach	$ 2	$ (1)	Market price per MWh	$ 20.90	$ 40.00

Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude of the change and the direction of the change for each input. The impact of changes to fair value, including changes from unobservable inputs, are subject to recovery or refund through the PPFAC mechanism and are reported as a regulatory asset or regulatory liability, or as a component of other comprehensive income, rather than in the income statement.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents a reconciliation of changes in the fair value of net assets and liabilities classified as Level 3 in the fair value hierarchy and the gains (losses) attributable to the change in unrealized gains (losses) relating to assets (liabilities) still held at the end of the period:

	Years Ended December 31,	
(in millions)	2017	2016
Beginning of Period	$ 1	$ (2)
Gains (Losses) Recorded		
Regulatory Assets or Liabilities, Derivative Instruments	1	2
Wholesale Revenues	4	4
Settlements	(4)	(3)
End of Period	$ 2	$ 1
Gains (Losses), Assets (Liabilities) still held	$ 2	$ 1

CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of non-performance by counterparties pursuant to the terms of their contractual obligations. TEP enters into contracts for the physical delivery of power and natural gas which contain remedies in the event of non-performance by the supply counterparties. In addition, volatile energy prices can create significant credit exposure from energy market receivables and subsequent measurement at fair value.

TEP has contractual agreements for energy procurement and hedging activities that contain certain provisions requiring TEP and its counterparties to post collateral under certain circumstances. These circumstances include: (i) exposures in excess of unsecured credit limits; (ii) credit rating downgrades; or (iii) a failure to meet certain financial ratios. In the event that such credit events were to occur, the Company, or its counterparties, would have to provide certain credit enhancements in the form of cash, a LOC, or other acceptable security to collateralize exposure beyond the allowed amounts.

TEP considers the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position, after incorporating collateral posted by counterparties, and then allocates the credit risk adjustment to individual contracts. TEP also considers the impact of its credit risk on instruments that are in a net liability position, after considering the collateral posted, and then allocates the credit risk adjustment to the individual contracts.

The value of all derivative instruments in net liability positions under contracts with credit risk-related contingent features, including contracts under the normal purchase normal sale exception, was $27 million as of December 31, 2017, compared with $8 million as of December 31, 2016. As of December 31, 2017, TEP had no LOCs as credit enhancements with its counterparties. If the credit risk contingent features were triggered on December 31, 2017, TEP would have been required to post an additional $27 million of collateral of which $12 million relates to outstanding net payable balances for settled positions.

FINANCIAL INSTRUMENTS NOT CARRIED AT FAIR VALUE

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. TEP uses the following methods and assumptions for estimating the fair value of financial instruments:

- Borrowings under revolving credit facilities approximate fair value due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For long-term debt, TEP uses quoted market prices, when available, or calculates the present value of the remaining cash flows as of the balance sheet date. When calculating present value, the Company uses current market rates for

bonds with similar characteristics such as credit rating and time-to-maturity. TEP considers the principal amounts of variable rate debt outstanding to be reasonable estimates of the fair value. The Company also incorporates the impact of its own credit risk using a credit default swap rate.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The following table includes the face value and estimated fair value of TEP's long-term debt:

	Fair Value Hierarchy	Face Value		Fair Value	
		December 31,			
(in millions)		2017	2016	2017	2016
Liabilities					
Long-Term Debt, including Current Maturities	Level 2	$1,466	$1,466	$1,547	$1,472

NOTE 12. INCOME TAXES

Income tax expense differs from the amount of income tax determined by applying the United States statutory federal income tax rate of 35% to pre-tax income due to the following:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Federal Income Tax Expense at Statutory Rate	$97	$64	$70
State Income Tax Expense, Net of Federal Deduction	9	6	8
Federal/State Tax Credits	(9)	(8)	(8)
Allowance for Equity Funds Used During Construction	(2)	(1)	(1)
Deferred Tax Asset Valuation Allowance	—	(2)	1
Impact of Enactment, TCJA	7	—	—
Other	(1)	—	2
Total Federal and State Income Tax Expense	$101	$59	$72

Income tax expense included in the income statement consists of the following:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Current Income Tax Expense			
Federal	$ —	$ —	$ —
State	—	—	—
Total Current Income Tax Expense	—	—	—
Deferred Income Tax Expense			
Federal	98	60	66
Federal Investment Tax Credits	(6)	(6)	(6