TUCSON ELECTRIC POWER CO
Form 10-Q
July 28, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 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
(Former name, former address and former fiscal year, if changed since last report): N/A

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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 Filer o Accelerated Filer o Non-Accelerated Filer x Smaller Reporting Company o Emerging Growth Company o
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
All shares of outstanding common stock of Tucson Electric Power Company are held by its parent company, UNS Energy Corporation, which is an indirect, wholly-owned subsidiary of Fortis Inc. There were 32,139,434 shares of common stock, no par value, outstanding as of July 27, 2017.

Table of Contents

DEFINITIONS

The abbreviations and acronyms used in the second quarter 2017 Form 10-Q are defined below:

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 units
Cooling Degrees Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures
DG	Distributed Generation
DSM	Demand Side Management
EE Standards	Energy Efficiency Standards
EPA	Environmental Protection Agency
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
GWh	Gigawatt-hour(s)
Heating Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting the average of the high and low daily temperatures from 65
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LOC	Letter(s) of Credit
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
NBV	Net Book Value
Phase 2	Second phase of TEP's rate case proceedings originally filed November 2015
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
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 costs of providing services and an opportunity to earn a reasonable return on its investment
San Juan	San Juan Generating Station
SES	Southwest Energy Solutions, Inc.
SJCC	San Juan Coal Company
Springerville	Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
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
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 Corporation
VIE	Variable Interest Entity

Table of Contents

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events, future operational, economical, 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 of our 2016 Form 10-K; Part II, Item 1A. Risk Factors; Part I, Item 2. 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; changes in, and compliance with, environmental laws and regulation decisions and policies that could increase operating and capital costs, reduce generating facility output, or accelerate generating 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 changing interest rate environment, which affect the value of our pension and other postretirement benefit plan assets and the related contribution requirements and expense; 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 (DG) 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; and the performance of TEP's generating facilities.

Table of Contents

PART I
ITEM 1. FINANCIAL STATEMENTS
TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited)
(Amounts in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Operating Revenues				
Retail	$280,537	$256,450	$480,043	$460,403
Wholesale	43,836	34,084	86,374	48,497
Other	27,771	26,950	54,109	52,063
Total Operating Revenues	352,144	317,484	620,526	560,963
Operating Expenses				
Fuel	59,744	68,236	126,472	130,914
Purchased Power	43,841	24,023	68,136	41,763
Transmission and Other PPFAC Recoverable Costs	7,983	5,312	16,882	10,490
Increase (Decrease) to Reflect PPFAC Recovery Treatment	(7,417)	7,470	(15,607)	14,265
Total Fuel and Purchased Power	104,151	105,041	195,883	197,432
Operations and Maintenance	84,490	86,580	166,631	171,579
Depreciation	38,208	35,913	76,365	71,545
Amortization	5,458	5,545	10,860	11,021
Taxes Other Than Income Taxes	12,980	12,700	26,780	25,730
Total Operating Expenses	245,287	245,779	476,519	477,307
Operating Income	106,857	71,705	144,007	83,656
Other Income (Deductions)				
Interest Income	433	29	526	67
Other Income	1,872	1,260	10,892	2,653
Other Expense	(776)	(463)	(1,537)	(886)
Appreciation in Value of Investments	484	660	1,218	860
Total Other Income (Deductions)	2,013	1,486	11,099	2,694
Interest Expense				
Long-Term Debt	15,494	15,486	30,930	30,977
Capital Leases	664	855	1,328	1,713
Other Interest Expense	208	135	423	258
Interest Capitalized	(590)	(397)	(1,120)	(861)
Total Interest Expense	15,776	16,079	31,561	32,087
Income Before Income Taxes	93,094	57,112	123,545	54,263
Income Tax Expense	32,159	16,576	41,851	14,429
Net Income	$60,935	$40,536	$81,694	$39,834

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Comprehensive Income				
Net Income	$60,935	$40,536	$81,694	$39,834
Other Comprehensive Income				
Net Changes in Fair Value of Cash Flow Hedges:				
Net of Income Tax Expense of $59 and $81	96	129		
Net of Income Tax Expense of $133 and $87			215	138
Supplemental Executive Retirement Plan Adjustments:				
Net of Income Tax Expense of $43 and $35	70	57		
Net of Income Tax Expense of $86 and $70			140	113
Total Other Comprehensive Income, Net of Tax	166	186	355	251
Total Comprehensive Income	$61,101	$40,722	$82,049	$40,085

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

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

	Six Months Ended June 30,	
	2017	2016
Cash Flows from Operating Activities		
Net Income	$81,694	$39,834
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation Expense	76,365	71,545
Amortization Expense	10,860	11,021
Amortization of Debt Issuance Costs	1,178	1,451
Use of Renewable Energy Credits for Compliance	11,245	8,403
Deferred Income Taxes	41,855	14,428
Pension and Other Postretirement Benefits Expense	8,019	7,669
Pension and Other Postretirement Benefits Funding	(5,165)	(5,694)
Allowance for Equity Funds Used During Construction	(2,792)	(2,203)
FERC Transmission Refund Payable	(4,878)	10,086
Changes in Current Assets and Current Liabilities:		
Accounts Receivable	(44,596)	(21,707)
Materials, Supplies, and Fuel Inventory	(4,825)	4,151
Regulatory Assets	(7,217)	(8,579)
Accounts Payable and Accrued Charges	26,848	11,985
Regulatory Liabilities	(10,299)	13,588
Other, Net	(8,475)	550
Net Cash Flows—Operating Activities	169,817	156,528
Cash Flows from Investing Activities		
Capital Expenditures	(151,207)	(135,344)
Purchase Intangibles, Renewable Energy Credits	(27,330)	(19,570)
Contributions in Aid of Construction	2,917	(722)
Other, Net	(975)	—
Net Cash Flows—Investing Activities	(176,595)	(155,636)
Cash Flows from Financing Activities		
Proceeds from Borrowings, Revolving Credit Facilities	15,000	—
Repayments of Borrowings, Revolving Credit Facilities	(15,000)	—
Payments of Capital Lease Obligations	(14,463)	(13,703)
Other, Net	320	(4,028)
Net Cash Flows—Financing Activities	(14,143)	(17,731)
Net Decrease in Cash and Cash Equivalents	(20,921)	(16,839)
Cash and Cash Equivalents, Beginning of Period	35,962	55,684
Cash and Cash Equivalents, End of Period	$15,041	$38,845

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

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

	June 30, 2017	December 31, 2016
ASSETS		
Utility Plant		
Plant in Service	$5,683,029	$5,975,139
Utility Plant Under Capital Leases	167,413	167,413
Construction Work in Progress	152,401	129,955
Total Utility Plant	6,002,843	6,272,507
Accumulated Depreciation and Amortization	(2,164,791)	(2,385,053)
Accumulated Amortization of Capital Lease Assets	(107,998)	(104,648)
Total Utility Plant, Net	3,730,054	3,782,806
Investments and Other Property	46,277	45,020
Current Assets		
Cash and Cash Equivalents	15,041	35,962
Accounts Receivable, Net	173,410	124,934
Fuel Inventory	29,686	25,887
Materials and Supplies	101,584	97,126
Regulatory Assets	66,846	56,340
Derivative Instruments	5,876	4,966
Other	15,977	13,793
Total Current Assets	408,420	359,008
Regulatory and Other Assets		
Regulatory Assets	253,746	225,453
Derivative Instruments	403	330
Other	49,941	37,372
Total Regulatory and Other Assets	304,090	263,155
Total Assets	$4,488,841	$4,449,989

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

(Continued)

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

	June 30, 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 June 30, 2017, and December 31, 2016)	$1,296,539	$1,296,539
Capital Stock Expense	(6,357)	(6,357)
Retained Earnings	355,102	273,408
Accumulated Other Comprehensive Loss	(4,200)	(4,555)
Total Common Stock Equity	1,641,084	1,559,035
Preferred Stock (No Par Value, 1,000,000 Shares Authorized, None Outstanding as of June 30, 2017, and December 31, 2016)	—	—
Capital Lease Obligations	28,164	39,267
Long-Term Debt, Net	1,453,747	1,453,072
Total Capitalization	3,122,995	3,051,374
Current Liabilities		
Capital Lease Obligations	48,110	51,765
Accounts Payable	108,921	89,797
Accrued Taxes Other than Income Taxes	41,578	37,639
Accrued Employee Expenses	23,638	29,465
Accrued Interest	14,635	14,508
Regulatory Liabilities	65,887	76,069
Customer Deposits	24,965	25,778
Derivative Instruments	3,671	2,641
Other	15,209	17,837
Total Current Liabilities	346,614	345,499
Regulatory and Other Liabilities		
Deferred Income Taxes, Net	575,038	529,148
Regulatory Liabilities	213,999	300,700
Pension and Other Postretirement Benefits	131,061	131,630
Derivative Instruments	5,576	2,629
Other	93,558	89,009
Total Regulatory and Other Liabilities	1,019,232	1,053,116
Commitments and Contingencies		
Total Capitalization and Other Liabilities	$4,488,841	$4,449,989

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

(Concluded)

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

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances as of December 31, 2015	$1,296,539	$(6,357)	$189,317	$ (4,564)	$ 1,474,935
Net Income			39,834		39,834
Other Comprehensive Income, Net of Tax				251	251
Adoption of ASU, Cumulative Effect Adjustment			9,653		9,653
Balances as of June 30, 2016	$1,296,539	$(6,357)	$238,804	$ (4,313)	$ 1,524,673

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances as of December 31, 2016	$1,296,539	$(6,357)	$273,408	$ (4,555)	$ 1,559,035
Net Income			81,694		81,694
Other Comprehensive Income, Net of Tax				355	355
Balances as of June 30, 2017	$1,296,539	$(6,357)	$355,102	$ (4,200)	$ 1,641,084

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

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION

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 Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly-owned subsidiary of Fortis Inc. (Fortis).

BASIS OF PRESENTATION

TEP's condensed consolidated financial statements and disclosures are presented in accordance with Generally Accepted Accounting Principles (GAAP) in the United States of America, including specific accounting guidance for regulated operations and the Securities and Exchange Commission's (SEC) interim reporting requirements.

The condensed 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 Condensed Consolidated Balance Sheets, and its proportionate share of the operating costs associated with these facilities is included in the income statement. These condensed consolidated financial statements exclude some information and footnotes required by GAAP and the SEC for annual financial statement reporting and should be read in conjunction with the consolidated financial statements and footnotes in TEP's 2016 Annual Report on Form 10-K.

The condensed consolidated financial statements are unaudited, but, in management's opinion, include all normal, recurring adjustments necessary for a fair presentation of the results for the interim periods presented. Because weather and other factors cause seasonal fluctuations in sales, TEP's quarterly operating results are not indicative of annual operating results.

Certain amounts from prior periods have been reclassified to conform to the current period presentation. TEP's Condensed Consolidated Statements of Cash Flows reflect a reclassification from Provision for Springerville Unit 1 - Third-Party Owners Unrealized Revenue to Changes in Current Assets and Current Liabilities—Accounts Receivable of $12 million for the six months ended June 30, 2016.

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 Purchased Power Agreements (PPA) 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 June 30, 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.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

Effective January 1, 2016, TEP adopted accounting guidance that simplifies the accounting for share-based payment accounting. The guidance requires that excess tax benefits and tax deficiencies be recorded as an income tax benefit or expense on the income statement and eliminates the requirement that excess tax benefits be realized before companies can recognize them. On adoption, using the modified retrospective method of transition, TEP recorded a cumulative effect adjustment of $10 million to increase retained earnings and decrease deferred income taxes related to prior period unrecognized excess tax benefits. The impact on the income and the cash flow statements was not significant. TEP elected to recognize forfeitures when they occur.

Table of Contents

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 as the Company recovers the cost of inventory through its rates.

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, less contributions in aid of construction.

Retirements

As of June 30, 2017, TEP recorded the early retirement of Unit 2 of the San Juan Generating Station (San Juan) and the coal handling facilities at H. Wilson Sundt Generating Station (Sundt) in accordance with the 2017 Rate Order. As a result of the 2017 Rate Order, the Condensed Consolidated Balance Sheets reflect a: (i) $224 million decrease in Plant in Service and Accumulated Depreciation and Amortization related to San Juan Unit 2; and (ii) $14 million decrease in Regulatory Assets and Accumulated Depreciation and Amortization related to the coal handling facilities at Sundt. See Note 2 for additional information related to the 2017 Rate Order.

Also in June 2017, the Navajo Nation approved a land lease extension which allows TEP and the co-owners of Navajo Generating Station (Navajo) to continue operations through December 2019 and begin decommissioning activities thereafter. TEP is currently recovering Navajo capital and operating costs in base rates using a useful life of 2030. As a result of the planned early retirement of Navajo, $38 million of the facility's net book value (NBV) and other related costs were reclassified from Utility Plant, Net to Regulatory Assets on the Condensed Consolidated Balance Sheets.

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. The Arizona Corporation Commission (ACC) approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). In the 2017 Rate Order, the ACC approved the results of a new depreciation study for TEP. To reflect the impact of the revised depreciation study on the estimated cost of removal, TEP transferred $87 million from Regulatory Liabilities to Accumulated Depreciation and Amortization on the Condensed Consolidated Balance Sheets as of June 30, 2017. See Note 2 for additional information related to the net cost of removal balance in Regulatory Liabilities.

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 (2017 Rate Order). 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 Unit 1 of Springerville Generating Station (Springerville) 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.

8

Table of Contents

The ACC deferred matters related to net metering and rate design for new DG customers to a second phase of TEP’s rate case (Phase 2), which is currently expected to be completed in the first quarter of 2018. TEP cannot predict the outcome of these proceedings.

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 Purchased Power and Fuel Adjustment Clause (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 rates designed to allow a regulated utility recovery of its costs of providing services and an opportunity to earn a reasonable return on its investment (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 $25 million as of June 30, 2017 and by $38 million as of December 31, 2016.

In February 2017, the ACC approved a PPFAC credit to begin returning the over-collected 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

Renewable Energy Standard

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.

In March 2017, the ACC approved TEP's 2017 RES implementation plan of $54 million, which was partially offset by applying $2 million of previously recovered carryover funds. TEP has been approved to recover the remaining $52 million through the RES surcharge. 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 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.

The percentage of retail kilowatt-hour (kWh) sales attributable to the RES in 2016 was 11%, which exceeded the overall 2016 RES renewable energy requirement of 6%. 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, which are used to demonstrate compliance with the DG requirement, the ACC approved a waiver of the 2016 and 2017 residential DG requirement.

Energy Efficiency Standards

TEP is required to implement cost-effective Demand Side Management (DSM) programs to comply with the ACC's Energy Efficiency Standards (EE Standards). The EE Standards provide regulated utilities a DSM surcharge to recover the costs to implement DSM programs from retail customers, 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, with $2 million recorded in both 2017 and 2016. This performance incentive is included in Retail Revenues on the Condensed Consolidated Statements of Income.

In February 2016, the ACC approved TEP's 2016 energy efficiency implementation plan which included 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 Lost Fixed Cost Recovery (LFCR) mechanism.

Table of Contents

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In June 2016, TEP notified the ACC that it would not file a 2017 implementation plan and instead continue the 2016 level of recovery through the end of 2017. TEP plans to reduce its costs and incentive levels for certain programs in order to minimize any potential under-collected DSM balance at the end of 2017. TEP expects to file its 2018 implementation plan by August 2017.

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 $5 million and $11 million in the three and six months ended June 30, 2017, respectively, and $4 million and $9 million in the three and six months ended June 30, 2016, respectively. LFCR revenues are included in Retail Revenues on the Condensed Consolidated Statements of Income.

REGULATORY ASSETS AND LIABILITIES

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

(dollars in millions)	Remaining Recovery Period (years)	June 30, 2017	December 31, 2016
Regulatory Assets			
Pension and Other Postretirement Benefits (Note 7)	Various	$ 124	$ 128
Final Mine Reclamation and Retiree Health Care Costs (1)	20	30	27
Navajo Costs (2)	13	38	—
Income Taxes Recoverable through Future Rates	Various	30	29
Lost Fixed Cost Recovery	1	29	23
Property Tax Deferrals	1	23	23
Springerville Unit 1 Leasehold Improvements (3)	6	15	17
Sundt Coal Handling Facilities (4)	N/A	—	14
Other Regulatory Assets	Various	32	20
Total Regulatory Assets		321	281
Less Current Portion	1	67	56
Total Non-Current Regulatory Assets		$ 254	$ 225
Regulatory Liabilities			
Net Cost of Removal (5)	Various	$187	$270
Renewable Energy Standard	Various	38	32
Purchased Power and Fuel Adjustment Clause	1	25	38
Deferred Investment Tax Credits	Various	21	23
Other Regulatory Liabilities	Various	9	14
Total Regulatory Liabilities		280	377
Less Current Portion	1	66	76
Total Non-Current Regulatory Liabilities		$214	$301

(1) Includes costs associated with TEP's jointly-owned facilities at San Juan, Four Corners Generating Station (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.

(2) As a result of the planned early retirement of Navajo, the NBV and other related costs were reclassified from Utility Plant, Net on the Condensed Consolidated Balance Sheets as of June 30, 2017. See Note 1 for additional

information related to the early retirement of Navajo.

Table of Contents
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) Represents investments TEP made 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.

(4) The ACC authorized TEP to apply excess depreciation reserves against the unrecovered NBV in the 2017 Rate Order.

(5) Net Cost of Removal 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.

Regulatory assets are either being collected or are expected to be collected through Retail Rates. With the exception of the Navajo 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 transmission service agreements (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 6 for additional information related to FERC compliance associated with these transmission contracts.

NOTE 3. ACCOUNTS RECEIVABLE

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

(in millions)	June 30, 2017	December 31, 2016
Customer	$ 92	$ 74
Due from Affiliates (Note 4)	7	9
Unbilled	61	34
Other	18	13
Allowance for Doubtful Accounts	(5)	(5)
Accounts Receivable, Net	$ 173	$ 125

NOTE 4. 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 Condensed Consolidated Balance Sheets:

(in millions)	June 30, 2017	December 31, 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	$ 2	$ 2
UNS Energy	1	—
Total Due to Related Parties	$ 3	$ 2

11

Table of Contents
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(in millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Goods and Services Provided by TEP to Affiliates				
Transmission Revenues, UNS Electric (1)	$ 2	$ 2	$ 3	$ 3
Control Area Services, UNS Electric (2)	1	1	1	1
Common Costs, UNS Energy Affiliates (3)	4	4	8	7
Goods and Services Provided by Affiliates to TEP				
Supplemental Workforce, SES (4)	4	3	7	7
Corporate Services, UNS Energy (5)	1	2	3	4
Corporate Services, UNS Energy Affiliates (6)	1	2	2	2

(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) 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 are deemed reasonable by management.

(5) 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 $1 million and $2 million for the three and six months ended June 30, 2017, respectively, and $2 million and $3 million for the three and six months ended June 30, 2016, respectively.

(6) 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 the three and six months ended June 30, 2017 or 2016.

DIVIDENDS PAID TO PARENT

TEP did not declare or pay dividends to UNS Energy in the three and six months ended June 30, 2017 or 2016. On July 24, 2017, TEP declared a $35 million dividend to UNS Energy to be paid by July 28, 2017.

NOTE 5. DEBT, CREDIT FACILITY, AND CAPITAL LEASE OBLIGATIONS

There have been no significant changes to TEP's debt, credit facility, or capital lease obligations from those reported in its 2016 Annual Report on Form 10-K, except as noted below.

CREDIT FACILITY

As of June 30, 2017, there was $250 million available under the revolving credit commitments and Letter of Credit (LOC) facility. As of July 27, 2017, TEP had $230 million available under its revolving credit commitments and LOC facility.

COVENANT COMPLIANCE

As of June 30, 2017, TEP was in compliance with the terms of its credit and long-term debt agreements.

12

NOTE 6. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

There have been no significant changes to TEP's long-term commitments from those reported in its 2016 Annual Report on Form 10-K.

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 condensed 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 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 Office of Surface Mining (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 National Environmental Policy Act (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 Arizona Public Service Company (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. Because the court has placed a stay on all litigation deadlines pending its decision regarding NTEC's motion to dismiss, the schedule for briefing and the anticipated timeline for completion of this litigation will likely be extended. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Claims Related to San Juan Generating Station

WildEarth Guardians

In February 2013, WildEarth Guardians (WEG) filed a Petition for Review in the U.S. District Court for the District of Colorado against the OSM challenging federal administrative decisions issued at various times from 2007 through 2012. In its petition, WEG challenges several unrelated mining plan modification approvals, which were each separately approved by the OSM. Of the claims for relief in the WEG Petition, two concern San Juan Coal Company's (SJCC) San Juan mine. WEG's allegations concerning the San Juan mine arise from the OSM administrative actions in 2008. WEG alleges various NEPA violations against the OSM, including, but not limited to, the OSM's alleged failure to provide requisite public notice and participation, alleged failure to analyze certain environmental impacts, and alleged reliance on outdated and insufficient documents. WEG's petition seeks various forms of relief, including a finding that the federal defendants violated the NEPA by approving the mine plans, voiding, reversing, and remanding the various mining modification approvals, enjoining the federal defendants from re-issuing the mining plan approvals for the mines until compliance with the NEPA has been demonstrated, and enjoining operations at the affected mines.

SJCC intervened in this matter. SJCC 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 proceeding. On July 18, 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 federal defendants' motion for remand to conduct further environmental analysis and complete an EIS by August 31, 2019. The order provided that the OSM's decision approving the mining plan will remain in effect during this process. The order further provides that if the EIS is not completed by August 31, 2019, then an order vacating the approved mine plan will become immediately effective, absent further court order. 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 reclamation mine 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 balance sheet reflected a total liability related to reclamation of $28 million as of June 30, 2017 and $26 million as of December 31, 2016.

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.

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, the FERC issued orders related to the late-filed TSAs which directed TEP to issue time-value refunds to the counterparties to these TSAs (FERC Refund Orders). 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. For the six months ended June 30, 2016, Wholesale Revenues on the Condensed Consolidated Statements of Income reflected $13 million related to the time-value refunds. As of December 31, 2016, Current Liabilities—Other on the Condensed 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 Condensed 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 Condensed Consolidated Balance Sheets, offsetting Wholesale Revenues on the Condensed Consolidated Statements of Income.

Performance Guarantees

TEP has joint participation agreements with participants at Navajo, San Juan, Four Corners, and with Luna Generating Station (Luna). The participants in each of the generation facilities, including TEP, have guaranteed certain performance obligations. Specifically, in the event of payment default, the non-defaulting participants have agreed to bear a 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 June 30, 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.

Table of Contents
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Environmental Matters

TEP is subject to federal, state, and local environmental laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species, and other environmental matters that have the potential to impact TEP's current and future operations. 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 condensed consolidated financial results. TEP expects to recover the cost of environmental compliance from its ratepayers. TEP believes it is in material compliance with applicable environmental laws and regulations.

NOTE 7. EMPLOYEE BENEFIT PLANS

Net periodic benefit cost includes the following components:

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended June 30,			
(in millions)	2017	2016	2017	2016
Service Cost	$3	$ 3	$ 1	$ 1
Interest Cost	4	3	1	1
Expected Return on Plan Assets	(6)	(6)	—	(1)
Amortization of Net Loss	2	2	—	—
Net Periodic Benefit Cost	$3	$ 2	$ 2	$ 1

	Pension Benefits		Other Postretirement Benefits	
	Six Months Ended June 30,			
(in millions)	2017	2016	2017	2016
Service Cost	$6	$ 6	$ 2	$ 2
Interest Cost	8	7	1	1
Expected Return on Plan Assets	(12)	(12)	—	(1)
Amortization of Net Loss	4	4	—	—
Net Periodic Benefit Cost	$6	$ 5	$ 3	$ 2

CONTRIBUTIONS

TEP contributed $3 million during the six months ended June 30, 2017 to the pension plans and expects to contribute a total of $9 million in 2017.

NOTE 8. SUPPLEMENTAL CASH FLOW INFORMATION

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:

Six Months Ended June 30,

(in millions)	2017	2016
Net Cost of Removal [1]	$ 82	$ —
Accrued Capital Expenditures	17	11

(1) Non-cash Net Cost of Removal 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.

Table of Contents
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 9. 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.

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. These assets and liabilities are 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)	June 30, 2017			
Assets				
Cash Equivalents[1]	$3	$—	$—	$ 3
Restricted Cash[1]	8	—	—	8
Energy Derivative Contracts, Regulatory Recovery[2]	—	1	1	2
Energy Derivative Contracts, No Regulatory Recovery[2]	—	—	4	4
Total Assets	11	1	5	17
Liabilities				
Energy Derivative Contracts, Regulatory Recovery[2]	—	(7)	(1)	(8)
Interest Rate Swap[3]	—	(1)	—	(1)
Total Liabilities	—	(8)	(1)	(9)
Total Assets (Liabilities), Net	$11	$(7)	$ 4	$ 8
(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 Condensed Consolidated Balance Sheets. Restricted cash is included in Investments and Other Property and in Current Assets—Other on the Condensed Consolidated Balance Sheets.

(2) Energy 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 Condensed 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 London Interbank Offered Rate (LIBOR) and is included in Derivative Instruments on the Condensed Consolidated Balance Sheets.

Table of Contents

NOTES TO CONDENSED 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.

(in millions)	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
	June 30, 2017			
Derivative Assets				
Energy Derivative Contracts	$6	$ 2	$ —	$ 4
Derivative Liabilities				
Energy Derivative Contracts	(8)	(2)	—	(6)
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 January 2020. 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.

Table of Contents
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The realized losses from its cash flow hedges are shown in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2017	2016	2017	2016
Capital Lease Interest Expense	$ —	$ —	$ —	$ 1

As of June 30, 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2017	2016	2017	2016
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$ —	$ 12	$(6)	$ 9

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 June 30, 2017, TEP had energy contracts that will settle on various expiration dates through 2020. The volumes associated with the energy contracts were as follows:

	June 30, 2017	December 31, 2016
Power Contracts GWh	4,322	2,610
Gas Contracts BBtu	28,950	12,355

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)	June 30, 2017					
Forward Power Contracts	Market approach	$5	$ (1)	Market price per MWh	$ 18.15	$ 39.95
(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.

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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2017	2016	2017	2016
Beginning of Period	$1	$(3)	$1	$(2)
Gains (Losses) Recorded				
Regulatory Assets or Liabilities, Derivative Instruments	—	3	2	2
Wholesale Revenues	4	3	4	3
Settlements	(1)	—	(3)	—
End of Period	$4	$3	$4	$3
Gains (Losses), Assets (Liabilities) still held	$5	$6	$4	$6

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.

Material adverse changes could trigger credit risk-related contingent features. 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 June 30, 2017, compared with $8 million as of December 31, 2016. As of June 30, 2017, TEP had no LOCs as credit enhancements with its counterparties. If the credit risk contingent features were triggered on June 30, 2017, TEP would have been required to post an additional $27 million of collateral of which $22 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 at 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.

Table of Contents

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:

(in millions)	Fair Value Hierarchy	Face Value June 30, 2017	Face Value December 31, 2016	Fair Value June 30, 2017	Fair Value December 31, 2016
Liabilities					
Long-Term Debt, including Current Maturities	Level 2	$1,466	$ 1,466	$1,522	$ 1,472

NOTE 10. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

TEP considers the applicability and impact of all accounting standard updates issued by the Financial Accounting Standards Board (FASB). The following updates have been issued, but have not yet been adopted by TEP. Updates not listed below were assessed and either determined to not be applicable or are expected to have a minimal impact on TEP's condensed consolidated financial position, results of operations, or disclosures.

REVENUE FROM CONTRACTS WITH CUSTOMERS

In May 2014, the FASB issued an accounting standard update that will eliminate the transaction and industry-specific revenue recognition guidance under current GAAP and replace it with a principles-based approach for determining revenue recognition. In July 2015, the FASB voted to defer the effective date of the revenue recognition standard by one year, and TEP is required to adopt the new guidance for annual and interim periods beginning January 1, 2018. The Company has elected not to early adopt this standard.

The revenue standard requires entities to apply the guidance retrospectively or under the modified retrospective approach by recognizing the cumulative effect of initially applying the guidance as an adjustment to the opening balance of retained earnings supplemented by additional disclosures. TEP expects to use the modified retrospective approach.

The sale of energy to retail and wholesale customers based on regulator-approved tariff rates represents TEP’s primary source of revenue and is considered in scope of this standard. TEP has assessed the retail and wholesale tariff-based revenues and does not expect that the adoption of this standard will change TEP’s accounting policy for recognizing retail and wholesale tariff-based revenues and, therefore, will not have an impact on earnings.

TEP continues to assess whether this standard will have an impact on its remaining revenue streams. The Company has not disclosed the expected impact of the adoption of this standard on its consolidated financial statements as it is not expected to be material. However, certain industry specific interpretative issues remain outstanding and the conclusions reached, if different than currently anticipated, could change the Company's expected method of adoption and have a material impact on its consolidated financial statements.

The adoption of this standard will impact the Company’s revenue disclosures as revenue from contracts with customers is required to be reported separately from alternative revenue, which is outside the scope of this standard. TEP is in the process of drafting these required disclosures.

As part of its effort to adopt the new revenue recognition standard, TEP is monitoring its adoption process under its existing Internal Control over Financial Reporting (ICFR), including accounting processes and the gathering and evaluation of information used in assessing the required disclosures. As the implementation process continues, TEP will assess any necessary changes to its ICFR.

LEASES

In February 2016, the FASB issued an accounting standard update that will require the recognition of leased assets and liabilities by lessees for those leases classified as operating leases under current GAAP. The standard is effective for periods beginning January 1, 2019, and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. TEP is evaluating the impact of this update to its financial statements and disclosures.

RESTRICTED CASH

In November 2016, the FASB issued an accounting standard update that will require entities to show the changes in the total of cash, cash equivalents, and restricted cash or restricted cash equivalents in the cash flow statement. As a result, entities will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the cash flow statement. The standard is effective for annual and interim periods beginning January 1, 2018, and is to be applied using a

Table of Contents

retrospective approach. Early adoption is permitted. TEP is evaluating the impact of this update to its financial statements and disclosures.

COMPENSATION—RETIREMENT BENEFITS

In March 2017, the FASB issued an accounting standard update to improve the presentation of net periodic benefit cost for pension and other postretirement benefits. The amendments in this update require that an employer disaggregate the service cost component from the other components of net periodic benefit cost. The guidance on the presentation of the components of net periodic benefit cost in the income statement will be applied retrospectively. The amendments also allow only the service cost component of net periodic benefit cost to be eligible for capitalization prospectively. The standard is effective for annual and interim periods beginning January 1, 2018. Early adoption is permitted. TEP is evaluating the impact of this update to its financial statements and disclosures.

Table of Contents

ITEM 2. 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 the second quarter and first six months of 2017 compared with the same periods of 2016;
- factors affecting our results of operations and outlook;
- liquidity and capital resources including contractual obligations, capital expenditures, and environmental matters;
- critical accounting policies and estimates; and
- recent accounting pronouncements.

Management’s Discussion and Analysis includes financial information prepared in accordance with 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 the condensed consolidated financial statements and accompanying notes that appear in Part I, Item 1 of this Form 10-Q. 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 Risk Factors in Part 1, Item 1A of our 2016 Annual Report on Form 10-K, and in Part II, Item 1A of this Form 10-Q.

References in this report to "we" and "our" are to TEP.

OUTLOOK AND STRATEGIES

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

- Achieving constructive outcomes in our regulatory proceedings that 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.

2017 Operational and Financial Highlights

For the first six months of 2017, Management's Discussion and Analysis includes the following notable items:

- In February 2017, the ACC issued a decision in TEP’s rate case 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.
- In 2016, TEP paid a total of $17 million in time-value refunds to counterparties in compliance with FERC orders related to late-filed TSAs. In January 2017, TEP and one of the TSA counterparties entered into a settlement agreement resulting in the counterparty paying TEP $8 million and TEP dismissing a previously filed appeal. In May

Table of Contents

2017, the FERC informed TEP that no further enforcement actions were necessary as the related investigation was closed.

- In June 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, $38 million of Navajo's NBV and other related costs were reclassified from Utility Plant, Net to Regulatory Assets on the Condensed Consolidated Balance Sheets as of June 30, 2017.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations in the second quarter and first six months of 2017 compared with the same periods in 2016. The significant items affecting net income are presented on an after-tax basis.

The second quarter of 2017 compared with the second quarter of 2016

TEP reported net income of $61 million in the second quarter of 2017 compared with $41 million in the second quarter of 2016. The increase of $20 million was primarily due to:

- $19 million in higher retail revenue primarily due to an increase to rates as approved in the 2017 Rate Order and an increase in usage due to favorable weather;
- $3 million related to the reversal of accrued refunds associated with late-filed TSAs. See Note 6 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q; and
- $2 million in higher wholesale revenue primarily due to favorable pricing on wholesale contracts in 2017.

The increase was partially offset by $3 million in lower net income as a result of a valuation allowance reduction in 2016 for deferred tax assets based on a change in projected taxable income.

The first six months of 2017 compared with the first six months of 2016

TEP reported net income of $82 million in the first six months of 2017 compared with net income of $40 million in the first six months of 2016. The increase of $42 million, was primarily due to:

- $22 million in higher retail revenue primarily due to an increase to rates as approved in the 2017 Rate Order and an increase in usage due to favorable weather;
- $16 million in higher net income associated with late-filed TSAs. See Note 6 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q;
- $5 million in higher wholesale revenue primarily due to favorable pricing on wholesale contracts in 2017; and
- $3 million in lower operations and maintenance expense resulting primarily from a decrease in maintenance expense due to planned outages in 2016.

The increase was partially offset by $4 million in lower net income as a result of a valuation allowance reduction in 2016 for deferred tax assets based on a change in projected taxable income.

Retail Sales and Revenues

The following tables provide a summary of retail kWh sales, a reconciliation of Retail Revenues from Retail Margin Revenues, and weather data for the second quarter of 2017 and 2016 and for the first six months of 2017 and 2016, respectively.

Table of Contents

Retail Revenues were $281 million in the second quarter of 2017 compared with $256 million in the second quarter of 2016. Retail Margin Revenues (non-GAAP) were $194 million in the second quarter of 2017 compared with $164 million in the second quarter of 2016.

	Three Months Ended June 30, 2017	2016	Increase (Decrease) Amount	Percent
Retail Sales by Customer Class (kWh in millions)				
Residential	1,019	950	69	7.3 %
Commercial	579	566	13	2.3 %
Industrial	483	494	(11)	(2.2)%
Mining	250	247	3	1.2 %
Public Authorities	4	7	(3)	(42.9)%
Total Retail Sales by Class	2,335	2,264	71	3.1 %
Retail Revenues (in millions)				
Residential	$92	$72	$20	27.8 %
Commercial	58	51	7	13.7 %
Industrial	27	26	1	3.8 %
Mining	10	9	1	11.1 %
Public Authorities	1	1	—	— %
Retail Margin Revenues by Class	188	159	29	18.2 %
LFCR Revenues	5	4	1	25.0 %
Other Retail Margin Revenues	1	1	—	— %
Retail Margin Revenues (non-GAAP) (1)	194	164	30	18.3 %
Fuel and Purchased Power Revenues	74	79	(5)	(6.3)%
DSM and RES Surcharge Revenues	13	13	—	— %
Total Retail Revenues (GAAP)	$281	$256	$25	9.8 %
Average Retail Margin Rate by Class (cents/kWh)				
Residential	9.03	7.58	1.45	19.1 %
Commercial	10.02	9.01	1.01	11.2 %
Industrial	5.59	5.26	0.33	6.3 %
Mining	4.00	3.64	0.36	9.9 %
Public Authorities (2)	8.52	5.79	2.73	47.2 %
Average Retail Margin Rate by Class	8.05	7.02	1.03	14.7 %
Total Average Retail Margin Rate (3)	8.31	7.24	1.07	14.8 %
Average Fuel and Purchased Power Rate	3.17	3.49	(0.32)	(9.2)%
Average DSM and RES Surcharge Rate	0.56	0.57	(0.01)	(1.8)%
Total Average Retail Rate	12.04	11.30	0.74	6.5 %
Weather Data				
Cooling Degree Days				
Actual	576	469	107	22.8 %
10-year Average	483	472	*	*
Heating Degree Days				
Actual	25	23	2	8.7 %
10-year Average	41	42	*	*

Table of Contents

Retail Revenues were $480 million in the first six months of 2017 compared with $460 million in the first six months of 2016. Retail Margin Revenues (non-GAAP) were $326 million in the first six months of 2017 compared with $292 million in the first six months of 2016.

	Six Months Ended June 30,		Increase (Decrease)		
	2017	2016	Amount	Percent	
Retail Sales by Customer Class (kWh in millions)					
Residential	1,705	1,647	58	3.5	%
Commercial	1,019	1,006	13	1.3	%
Industrial	928	947	(19)	(2.0)	%
Mining	495	498	(3)	(0.6)	%
Public Authorities	9	16	(7)	(43.8)	%
Total Retail Sales by Class	4,156	4,114	42	1.0	%
Retail Revenues (in millions)					
Residential	$149	$125	$24	19.2	%
Commercial	95	86	9	10.5	%
Industrial	49	50	(1)	(2.0)	%
Mining	18	17	1	5.9	%
Public Authorities	1	1	—	—	%
Retail Margin Revenues by Class	312	279	33	11.8	%
LFCR Revenues	11	9	2	22.2	%
DSM Performance Bonus	2	2	—	—	%
Other Retail Margin Revenues	1	2	(1)	(50.0)	%
Retail Margin Revenues (non-GAAP) (1)	326	292	34	11.6	%
Fuel and Purchased Power Revenues	128	145	(17)	(11.7)	%
DSM and RES Surcharge Revenues	26	23	3	13.0	%
Total Retail Revenues (GAAP)	$480	$460	$20	4.3	%
Average Retail Margin Rate by Class (cents/kWh)					
Residential	8.74	7.59	1.15	15.2	%
Commercial	9.32	8.55	0.77	9.0	%
Industrial	5.28	5.28	—	—	%
Mining	3.64	3.41	0.23	6.7	%
Public Authorities (2)	7.29	5.64	1.65	29.3	%
Average Retail Margin Rate by Class	7.51	6.78	0.73	10.8	%
Total Average Retail Margin Rate (3)	7.84	7.10	0.74	10.4	%
Average Fuel and Purchased Power Rate	3.08	3.52	(0.44)	(12.5)	%
Average DSM and RES Surcharge Rate	0.63	0.56	0.07	12.5	%
Total Average Retail Rate	11.55	11.18	0.37	3.3	%
Weather Data					
Cooling Degree Days					
Actual	586	469	117	24.9	%
10-year Average	484	473	*	*	
Heating Degree Days					
Actual	614	629	(15)	(2.4)	%
10-year Average	739	773	*	*	

* Not meaningful

(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. We believe 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 certain Other Retail Margin Revenues available to cover the non-fuel operating expenses of our core utility business.

(2) Calculated on unrounded data and may not correspond exactly to data shown in table.

(3) Total Average Retail Margin Rate includes revenue related to LFCR Revenues, DSM Performance Bonus, and Other Retail Margin Revenues included in Retail Margin Revenues.

Retail Revenues increased in the second quarter and in the first six months of 2017 when compared with the same periods in 2016 primarily due to higher retail margin revenues related to an increase to rates as approved in the 2017 Rate Order and an increase in usage due to favorable weather. The increases were partially offset by a decrease in Fuel and Purchased Power Revenues related to reduced recoveries due to changes in the PPFAC rate. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information on the PPFAC mechanism.

Wholesale Revenues

(in millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Long-Term Wholesale	$12	$ 10	$19	$16
Short-Term Wholesale	20	16	47	30
Transmission	7	8	15	15
Transmission Refunds [1]	5	—	5	(13)
Total Wholesale Revenues	$44	$ 34	$86	$48

(1) In 2016, FERC ordered TEP to make refunds associated with various late-filed TSAs for the time period during which rates were charged without FERC authorization. In May 2017, FERC informed TEP that no further enforcement actions were necessary as the related investigation was closed. See Note 6 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information on the FERC ordered refunds.

Wholesale Revenues increased by $10 million, or 29%, and $38 million, or 79%, in the second quarter and first six months of 2017, respectively, compared with the same periods in 2016. The increases were primarily due to: (i) time-value FERC ordered refunds in 2016 and the reversal of accrued refunds in May 2017, both related to late-filed TSAs; (ii) favorable commodity pricing on the wholesale market; and (iii) an increase in Short-Term Wholesale volumes in the first quarter of 2017.

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

(in millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Springerville Units 3 and 4 [1]	$19	$ 20	$38	$ 38
Other	9	7	16	14
Total Other Revenues	$28	$ 27	$54	$ 52

(1) Represents revenues and reimbursements to TEP from Tri-State Generation and Transmission Association, Inc. (Tri-State), the lessee of Springerville Unit 3, and Salt River Project Agricultural Improvement and Power District (SRP), the owner of Springerville Unit 4, related to the operation of these generation facilities.

Other Revenues includes: (i) reimbursements related to Springerville Units 3 and 4; (ii) inter-company revenues from TEP's affiliates, UNS Gas and UNS Electric, for corporate services provided by TEP; and (iii) miscellaneous service-related revenues such as rent on power pole attachments, damage claims, and customer late fees.
There were no significant changes to Other Revenues in the second quarter or the first six months of 2017 when compared with the same periods in 2016.

Table of Contents

Operating Expenses

Generating Output and Fuel and Purchased Power Expense

TEP's fuel and purchased power expense and energy resources are detailed in the following tables:

	Generation and Purchased Power (kWh)		Fuel and Purchased Power Expense	
	Three Months Ended June 30,			
(in millions)	2017	2016	2017	2016
Coal-Fired Generation	1,543	1,965	$ 34	$ 44
Gas-Fired Generation	746	817	25	23
Utility Owned Renewable Generation	27	19	—	—
Reimbursed Fuel Expense, Springerville Units 3 and 4 (1)	—	—	1	1
Total Generation	2,316	2,801	60	68
Purchased Power, Non-Renewable	862	366	33	10
Purchased Power, Renewable	211	211	11	14
Total Purchased Power	1,073	577	44	24
Transmission and Other PPFAC Recoverable Costs	—	—	8	5
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	(8)	8
Total Generation and Purchased Power	3,389	3,378	$ 104	$ 105
Less Line Losses and Company Use	210	202		
Total Power Sold	3,179	3,176		

	Six Months Ended June 30,			
(in millions)	2017	2016	2017	2016
Coal-Fired Generation	3,552	3,589	$82	$87
Gas-Fired Generation	1,275	1,651	42	41
Utility Owned Renewable Generation	45	34	—	—
Reimbursed Fuel Expense, Springerville Units 3 and 4 (1)	—	—	3	3
Total Generation	4,872	5,274	127	131
Purchased Power, Non-Renewable	1,325	579	46	16
Purchased Power, Renewable	367	364	22	26
Total Purchased Power	1,692	943	68	42
Transmission and Other PPFAC Recoverable Costs	—	—	17	10
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	(16)	14
Total Generation and Purchased Power	6,564	6,217	$196	$197
Less Line Losses and Company Use	365	352		
Total Power Sold	6,199	5,865		

(1) Springerville Units 3 and 4 Fuel Expense is reimbursed by Tri-State and SRP.

Fuel and Purchased Power Expense decreased by $1 million, or 1%, for both the second quarter and first six months of 2017, compared with the same periods in 2016. The decreases were primarily due to the reduction in recovery of the PPFAC costs as a result of changes in the PPFAC rate, and a decrease in Coal-Fired Generation costs as a result of unplanned outages. The decreases were partially offset by an increase in Purchased Power costs used to compensate for the decrease in Coal-Fired Generation.

Table of Contents

The table below summarizes average fuel cost of generated and purchased power kWh:

(cents per kWh)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Coal	2.21	2.26	2.30	2.41
Gas	3.30	2.80	3.30	2.52
Purchased Power, Non-Renewable	3.78	2.43	3.50	2.35
Purchased Power, Renewable	5.33	6.58	5.93	7.09
All Resources (1)	3.51	3.31	3.41	3.37

(1) Calculated on unrounded data and may not correspond exactly to data shown in Generation Output and Fuel and Purchased Power Expense table above.

Operations and Maintenance Expense

The table below summarizes the items included in Operations and Maintenance Expense:

(in millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Reimbursed Expenses, Springerville Units 3 and 4 (1)	$ 14	$ 14	$ 26	$ 25
Reimbursed Expenses, Customer Funded Renewable Energy and DSM Programs (2)	7	7	13	12
Other (3)	63	66	128	135
Total Operations and Maintenance Expense	$ 84	$ 87	$ 167	$ 172

(1) Expenses related to Springerville Units 3 and 4 are reimbursed with corresponding amounts recorded in Other Revenue.

(2) These expenses are collected from customers and the corresponding amounts are recorded in Retail Revenue.

(3) Includes the Third-Party Owners' share of expenses related to Springerville Unit 1 for the first six months of 2016.

Operations and Maintenance Expense decreased by $3 million, or 3%, and $5 million, or 3%, in the second quarter and first six months of 2017, respectively, compared with the same periods in 2016. The decreases were primarily due to a decrease in maintenance expense related to planned outages in 2016 and a sales tax refund in the second quarter of 2017.

FACTORS AFFECTING RESULTS OF OPERATIONS

Regulatory Matters

TEP is subject to comprehensive regulation. The discussion below contains material developments to those matters disclosed in Part II, Item 7 of our 2016 Annual Report on Form 10-K and new regulatory matters occurring in 2017.

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%;
- 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

Table of Contents

- 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 quarter of 2018. See Phase 2 Proceedings below.

Distributed Generation

In 2016, the ACC held proceedings under the Value and Cost of Distributed Generation 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. Consistent with the ACC's decision in the Value of DG docket proceedings, 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 annually 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 by first quarter 2018. TEP cannot predict the outcome of these proceedings.

Generating Resources

As of June 30, 2017, approximately 52% of TEP's peak generation capacity is coal-fired generation. TEP is evaluating additional steps to reduce its reliance on coal-fired generation.

Integrated Resource Plan

TEP's long-term strategy to build 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 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.

Table of Contents

See Part I, Item 2. Liquidity and Capital Resources, Environmental Matters of this Form 10-Q for additional information regarding the impact of environmental matters on generation facility operations.

Navajo Generating Station

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. 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, $38 million, of the facility's NBV and other related costs were reclassified from Utility Plant, Net to Regulatory Assets on the Condensed Consolidated Balance Sheets as of June 30, 2017. We plan to seek recovery of all unrecovered costs in our next ACC rate case. Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

Long-Term Wholesale Sales

Navopache Electric Cooperative

In January 2017, a new long-term contract with Navopache Electric Cooperative (NEC) became effective. The contract expires at the end of 2041. TEP expects to serve 80% of NEC’s load requirements in 2017 and 100% beginning in 2018. In the six months ended June 30, 2017, revenues from the NEC contract accounted for 3% of total Wholesale Revenues on the Condensed Consolidated Statements of Income.

Interest Rates

See Part II, Item 7A in our 2016 Annual Report on Form 10-K and Part II, Item 3 of this Form 10-Q 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. As a result of the varied seasonal cash flow, we will use, as needed, our revolving credit facility 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)	June 30, 2017
Cash and Cash Equivalents	$ 15
Amount Available under Revolving Credit Facility (1)	250
Total Liquidity	$ 265

(1) TEP's revolving credit facility provides for $250 million of revolving credit commitments with a LOC sublimit of $50 million through its original maturity date of October 2020. In October 2016, TEP extended the agreement one year to October 2021. The credit facility commitments will be reduced to $217.5 million in the final year of the agreement.

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 included in the Contractual Obligations and forecasted Capital Expenditures tables reported in our 2016 Annual Report on Form 10-K and the material changes summarized below in the respective sections.

Table of Contents

Summary of Cash Flows

The table below presents net cash provided by (used for) operating, investing, and financing activities:

	Six Months Ended June 30,		Increase (Decrease)
(in millions)	2017	2016	Percent
Operating Activities	$170	$157	8.3 %
Investing Activities	(177)	(156)	13.5 %
Financing Activities	(14)	(18)	(22.2)%
Net Decrease in Cash and Cash Equivalents	(21)	(17)	(23.5)%
Cash and Cash Equivalents, Beginning of Period	36	56	(35.7)%
Cash and Cash Equivalents, End of Period	$15	$39	(61.5)%

Operating Activities

In the first six months of 2017, net cash flows from operating activities increased by $13 million compared with the same period in 2016. The increase is primarily due to $8 million in higher cash proceeds received in 2017 from a settlement agreement with counterparties related to the late-filed TSAs and higher net income due to an increase in: (i) rates as approved in the 2017 Rate Order; and (ii) residential usage due to favorable weather. The increase was partially offset by changes in working capital related to the timing of billing collections and payments.

Investing Activities

In the first six months of 2017, net cash flows used for investing activities increased by $21 million compared with the same period in 2016 primarily due to an increase in cash paid for capital expenditures.

Financing Activities

In the first six months of 2017, net cash flows used for financing activities did not vary significantly compared with the same period in 2016.

External 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 June 30, 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 June 30, 2017, there was $250 million available under the revolving credit commitments and LOC facilities. As of July 27, 2017, TEP had $230 million available under its 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 in our 2016 Annual Report on Form 10-K.

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.

Table of Contents

We have no plans to raise additional capital in 2017. 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.

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+, and as of June 30, 2017 the credit rating remained unchanged. As of June 30, 2017, Moody's Investors Service credit ratings for TEP's senior unsecured debt remained unchanged at 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.

Debt Covenants

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. Also, under certain agreements, should TEP fail to maintain compliance with covenants, lenders could accelerate the maturity of all amounts outstanding. As of June 30, 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.

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 June 30, 2017, TEP had posted no LOCs as credit enhancements with its counterparties.

Contribution from Parent

TEP received no equity contributions in the three and six months ended June 30, 2017 or 2016.

Dividends Paid to Parent

TEP did not declare or pay dividends to UNS Energy in the three and six months ended June 30, 2017 or 2016. On July 24, 2017, TEP declared a $35 million dividend to UNS Energy to be paid by July 28, 2017.

Capital Expenditures

TEP's capital expenditures include funds used for customer growth, system reinforcement, replacements and betterments, and costs to comply with environmental rules and regulations. Our capital expenditures in the first six months of 2017 were $151 million compared to $135 million for the same period 2016. TEP's forecasted capital expenditures are summarized below:

(in millions)	2017	2018	2019	2020	2021
Generation Facilities:					
Environmental Compliance	$23	$11	$1	$2	$—
Renewable Energy	6	15	21	26	26
Springerville Common Lease Purchase	38	—	—	—	9
Replacement Generation Capacity (1)	13	132	190	53	29
Other Generation Facilities	41	80	35	76	63
Total Generation Facilities	121	238	247	157	127
Transmission and Distribution	167	176	161	169	162
General and Other (2)	76	76	106	53	39
Total Capital Expenditures	$364	$490	$514	$379	$328

(1) Investments that will provide replacement capacity for planned coal-fired generation retirements.

Table of Contents

(2) 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

In the first six months of 2017, there have been no material changes outside the ordinary course of business to contractual obligations as reported in our 2016 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

Other than the unrecorded contractual obligations reported on the contractual obligations table presented in our 2016 Annual Report on Form 10-K, we do not have any arrangements or relationships with entities that are not consolidated into the financial statements.

Income Tax Position

Prior year tax legislation and the Consolidated Appropriations Act of 2016 include provisions that make qualified property placed in service between 2010 and 2019 eligible for bonus depreciation for tax purposes. In addition, the IRS issued new guidance related to the treatment of expenditures to maintain, replace, or improve property. These provisions are an acceleration of tax benefits TEP otherwise would have received over 20 years and have created net operating loss carryforwards that can be used to offset future taxable income. As a result, TEP did not pay any federal or state income taxes in the first six months of 2017 and does not expect to make any payments until 2020.

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 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, TEP is 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. TEP expects to recover the cost of environmental compliance through 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. The costs to comply with the BART rule, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of Navajo and Four Corners or for individual owners to continue to participate in these generation facilities. 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.

Four Corners

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 the installation of

33

Table of Contents

Selective Catalytic Reduction (SCR) on Units 4 and 5 by July 2018. 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.

Navajo

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.

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 Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the early retirement of Navajo.

San Juan

In October 2014, the EPA published a final rule approving a revised SIP covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017 and the installation of Selective Non-Catalytic Reduction (SNCR) on Units 1 and 4. TEP owns 50% of Units 1 and 2 at San Juan. Public Service Company of New Mexico (PNM), the operator of San Juan, completed the installation of SNCR in February 2016. PNM obtained New Mexico Public Regulation Commission approval to shut down Units 2 and 3 at San Juan.

In anticipation of the retirement of San Juan Unit 2 in December 2017, TEP applied excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order. See Note 1 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the retirement of San Juan Unit 2.

Sundt

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. Under the rule, TEP was required to notify the EPA of its decision by March 2017.

In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source to comply with the better-than-BART alternative emission limits. TEP applied excess depreciation reserves against the unrecovered NBV of the coal handling facilities at Sundt as approved in the 2017 Rate Order. See Note 1 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the retirement of the coal handling facilities at Sundt.

Greenhouse Gas Regulation

In August 2015, the EPA issued the CPP limiting CO_2 emissions from existing and new fossil fueled generation facilities. The Clean Power Plan (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. States were required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. States that received an extension are required to submit a final completed plan to the EPA by September 2018.

The EPA incorporated the compliance obligations for existing generation facilities located in Indian Country, like the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or state approved plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP has submitted comments on the proposed Federal Plan impacting our facilities, including Four Corners and Navajo, stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from

compliance with the Regional Haze Rules will be equivalent to those required under the CPP rule.
TEP's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016, the U.S. Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation

efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP rule.

In September 2016, the U.S. Court of Appeals for the District of Columbia Circuit (U.S. Court of Appeals) heard oral arguments on the CPP. On March 28, 2017, the Department of Justice filed a motion to hold the lawsuits related to the CPP in abeyance. On April 28, 2017, the U.S. Court of Appeals granted that motion and delayed for 60 days litigation over the EPA's CPP for existing and new generation facilities. The EPA has asked for an extension.

On March 28, 2017, a Presidential Executive Order (EO) titled "Promoting Energy Independence and Economic Growth" was issued. The EO instructs the EPA to review the final greenhouse gas rule for existing and new and modified generation facilities and either suspend, revise, or rescind the rule as appropriate. In April 2017, the EPA announced in the Federal Register that it is reviewing and, if appropriate, will initiate proceedings to suspend, revise, or rescind the CPP rule. In June 2017, the EPA sent the Office of Management and Budget a draft proposed rule for review. The contents of the proposed rule are not known at this time.

TEP will continue to work with the Arizona Department of Environmental Quality (ADEQ) to determine what, if any, actions need to be taken in light of recent events. TEP cannot predict the ultimate outcome of these matters.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated 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 while allowing for the continued recycling of coal ash. TEP does not operate any impoundments. Under the rule, the Springerville ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP’s share of costs at Springerville is estimated to be $2 million, the majority of which is expected to be capital expenditures. TEP currently estimates its 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 expected to be 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 ADEQ to explore the possibility of developing a State administered program to enforce CCR regulation.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's Discussion and Analysis of Financial Condition and Results of Operations is based on our Condensed Consolidated Financial Statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires management to apply accounting policies and make estimates, judgments, and assumptions that affect the reported amounts of assets, liabilities, net revenues and expenses, and disclosure of contingent liabilities. Management believes that there have been no significant changes during the six months ended June 30, 2017, to the items that we disclosed as our critical accounting policies and estimates in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2016 Annual Report on Form 10-K.

ACCOUNTING PRONOUNCEMENTS

For a discussion of new accounting pronouncements affecting TEP, see Note 10 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

Table of Contents

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

TEP’s primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. We can enter into interest rate swaps and financing transactions to manage changes in interest rates. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms.

There have been no additional risks and no material changes to market risks disclosed in Part II, Item 7A in our 2016 Annual Report on Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

TEP’s Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer) supervised and participated in TEP’s evaluation of its disclosure controls and procedures as such term is defined under Rule 13(a) – 15(e) or Rule 15(d) – 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this report. Disclosure controls and procedures are controls and procedures designed to ensure that information required to be disclosed in TEP’s periodic reports filed or submitted under the Exchange Act, is recorded, processed, summarized, and reported within the time periods specified in the United States SEC’s rules and forms. These disclosure controls and procedures are also designed to ensure that information required to be disclosed by TEP in the reports that it files or submits under the Exchange Act is accumulated and communicated to management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based upon the evaluation performed, TEP’s Chief Executive Officer and Chief Financial Officer concluded that TEP’s disclosure controls and procedures are effective as of June 30, 2017.

While TEP continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting, there has been no change in TEP’s ICFR during the quarter ended June 30, 2017, that has materially affected, or is reasonably likely to materially affect, TEP’s IFCR.

Table of Contents

PART II

ITEM 1. LEGAL PROCEEDINGS

For a description of certain legal proceedings affecting TEP, refer to Note 6 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

The business and financial results of TEP are subject to numerous risks and uncertainties. As a result, the risks and uncertainties discussed in Part I, Item 1A. Risk Factors in our 2016 Form 10-K should be carefully considered. There have been no material changes in the assessment of our risk factors from those set forth in our 2016 Form 10-K.

ITEM 5. OTHER INFORMATION

RATIO OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30, 2017	Twelve Months Ended June 30, 2017
Ratio of Earnings to Fixed Charges	4.53	4.67

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 and expense, interest on operating lease payments, and expense on indebtedness, including capital lease obligations.

ITEM 6. EXHIBITS

See Exhibit Index.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		TUCSON ELECTRIC POWER COMPANY
		(Registrant)
Date:	July 28, 2017	/s/ Frank P. Marino
		Frank P. Marino
		Vice President and Chief Financial Officer
		(Principal Financial Officer)

EXHIBIT INDEX

12	—	Computation of Ratio of Earnings to Fixed Charges
31(a)	—	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by David G. Hutchens
31(b)	—	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by Frank P. Marino
*32	—	Statements of Corporate Officers (pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)
101.INS	—	XBRL Instance Document
101.SCH	—	XBRL Taxonomy Extension Schema Document
101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	—	XBRL Taxonomy

	Extension Label Linkbase Document
101.PRE —	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF —	XBRL Taxonomy Extension Definition Linkbase Document

* Pursuant to Item 601(b)(32)(ii) of Regulation S-K, this certificate is not being "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

39