TUCSON ELECTRIC POWER CO
Form 10-Q
July 29, 2016

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, 2016
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	86-0062700
(State or other jurisdiction of incorporation or organization)	(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 ¨
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 ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer,” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer ¨ Accelerated Filer ¨ Non-accelerated Filer x Smaller Reporting Company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ¨ 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 28, 2016.

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DEFINITIONS

The abbreviations and acronyms used in the second quarter 2016 Form 10-Q are defined below:

2013 Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective July 1, 2013
2015 Credit Agreement	The 2015 Credit Agreement provides for a $250 million revolving credit and letter of credit facility with a letter of credit sublimit of $50 million; the credit agreement matures in 2020
2015 Rate Case	A pending general rate case filed with the ACC by TEP in November 2015 requesting new rates effective January 1, 2017
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
Base Rates	The portion of Retail Rates attributed to generation, transmission, distribution, and customer costs. Base Rates exclude authorized charges designed to recover specific costs that are passed through to customers including all fuel and purchased power costs, energy efficiency program costs, certain environmental compliance costs, and a portion of renewable energy costs
Cooling Degree 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
DSM	Demand Side Management
EE Standards	Energy Efficiency Standards
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FERC Refund Order	FERC order issued on April 21, 2016, relating to TEP late-filed transmission service agreements, which directs TEP to issue time value refunds to the relevant counterparties to the agreements
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
GBtu	Billion British thermal units
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
MATS	Mercury and Air Toxics Standards
MMBtu	Million British thermal units
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility to recover its costs of providing services and an opportunity to earn a reasonable return on its investment
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction
SES	Southwest Energy Solutions, Inc.
SJCC	San Juan Coal Company

SNCR	Selective Non-Catalytic Reduction
Springerville	Springerville Generating Station

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Springerville Coal Handling Facilities	Coal handling facilities at Springerville used by all four Springerville units
Springerville Common Facilities	Facilities at Springerville used in common by Springerville Units 1 and 2
Springerville Unit 1 Leases	Leveraged lease arrangements relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities
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 the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners)
Tri-State	Tri-State Generation and Transmission Association, Inc.
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy
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 including UNS Electric, Inc., UNS Gas, Inc., and Southwest Energy Solutions, Inc.
UNS Gas	UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy

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FORWARD-LOOKING INFORMATION

This 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) 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 or for TEP in this Quarterly Report on Form 10-Q. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events, future operational or financial performance and underlying assumptions, and other statements that are not statements of historical facts. Forward-looking statements may be identified by the use of words such as anticipates, believes, estimates, expects, intends, may, plans, predicts, 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 2015 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; the performance of the stock market and changing interest rate environment, which affect the value of our pension and other retiree benefit plan assets and the related contribution requirements and expense; the inability to make additions to our existing high voltage transmission system; unexpected increases in O&M expense; resolution of pending litigation matters; changes in accounting standards; changes in our critical accounting policies and estimates; the ongoing impact of mandated energy efficiency and distributed generation initiatives; changes to long-term contracts; the cost of fuel and power supplies; the ability to obtain coal from our suppliers; cyber attacks or challenges to our information security; and the performance of TEP's generating plants.

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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,	
	2016	2015	2016	2015
Operating Revenues				
Retail	$256,450	$264,297	$460,403	$465,920
Wholesale	34,084	47,674	48,497	89,136
Other	26,950	28,204	52,063	58,512
Total Operating Revenues	317,484	340,175	560,963	613,568
Operating Expenses				
Fuel	68,236	77,067	130,914	147,636
Purchased Power	24,023	36,885	41,763	67,407
Transmission and Other PPFAC Recoverable Costs	5,312	6,873	10,490	11,580
Increase (Decrease) to Reflect PPFAC Recovery Treatment	7,470	7,532	14,265	10,781
Total Fuel and Purchased Power	105,041	128,357	197,432	237,404
Operations and Maintenance	86,580	85,655	171,579	168,300
Depreciation	35,913	34,219	71,545	68,952
Amortization	5,545	4,619	11,021	10,181
Taxes Other Than Income Taxes	12,700	12,935	25,730	26,146
Total Operating Expenses	245,779	265,785	477,307	510,983
Operating Income	71,705	74,390	83,656	102,585
Other Income (Deductions)				
Interest Income	29	22	67	51
Other Income	1,260	1,436	2,653	2,058
Other Expense	(463)	(656)	(886)	(1,118)
Appreciation (Depreciation) in Value of Investments	660	(539)	860	241
Total Other Income (Deductions)	1,486	263	2,694	1,232
Interest Expense				
Long-Term Debt	15,486	15,706	30,977	30,116
Capital Leases	855	1,007	1,713	2,012
Other Interest Expense	135	430	258	864
Interest Capitalized	(397)	(741)	(861)	(1,196)
Total Interest Expense	16,079	16,402	32,087	31,796
Income Before Income Taxes	57,112	58,251	54,263	72,021
Income Tax Expense	16,576	20,425	14,429	24,766
Net Income	$40,536	$37,826	$39,834	$47,255

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,	
	2016	2015	2016	2015
Comprehensive Income				
Net Income	$40,536	$37,826	$39,834	$47,255
Other Comprehensive Income (Loss)				
Net Changes in Fair Value of Cash Flow Hedges:				
Net of Income Tax (Expense) Benefit of ($81) and ($282)	129	441		
Net of Income Tax (Expense) Benefit of ($87) and ($294)			138	455
Supplemental Executive Retirement Plan Adjustments:				
Net of Income Tax (Expense) Benefit of ($35) and ($38)	57	61		
Net of Income Tax (Expense) Benefit of ($70) and ($75)			113	121
Total Other Comprehensive Income (Loss), Net of Tax	186	502	251	576
Total Comprehensive Income	$40,722	$38,328	$40,085	$47,831

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,	
	2016	2015
Cash Flows from Operating Activities		
Net Income	$39,834	$47,255
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation Expense	71,545	68,952
Amortization Expense	11,021	10,181
Amortization of Debt Issuance Costs	1,451	1,499
Provision for Springerville Unit 1 - Third-Party Owners Unrealized Revenue	12,041	11,170
Use of Renewable Energy Credits for Compliance	8,403	12,014
Deferred Income Taxes	14,428	23,835
Pension and Retiree Expense	7,669	9,294
Pension and Retiree Funding	(5,694)	(9,886)
Share-Based Compensation Expense	1,244	672
Allowance for Equity Funds Used During Construction	(2,203)	(1,419)
FERC Refund Order	10,086	—
Changes in Current Assets and Current Liabilities:		
Accounts Receivable	(33,748)	(44,886)
Materials, Supplies, and Fuel Inventory	4,151	(3,326)
Regulatory Assets	(8,579)	6,183
Accounts Payable and Accrued Charges	11,985	9,590
Regulatory Liabilities	13,588	(7,727)
Other, Net	(694)	(4,564)
Net Cash Flows—Operating Activities	156,528	128,837
Cash Flows from Investing Activities		
Capital Expenditures	(135,344)	(194,915)
Purchase of Springerville Coal Handling Facilities Lease Assets	—	(120,312)
Purchase of Springerville Unit 1 Lease Assets	—	(45,753)
Proceeds from Sale of Springerville Coal Handling Facilities	—	23,656
Purchase of Intangibles - Renewable Energy Credits	(19,570)	(15,002)
Contributions in Aid of Construction	(722)	3,297
Net Cash Flows—Investing Activities	(155,636)	(349,029)
Cash Flows from Financing Activities		
Proceeds from Borrowings Under Revolving Credit Facilities	—	148,000
Repayments of Borrowings Under Revolving Credit Facilities	—	(233,000)
Proceeds from Borrowings Under Term Loan	—	130,000
Repayments of Borrowings Under Term Loan	—	(130,000)
Proceeds from Issuance of Long-Term Debt	—	299,019
Repayments of Long-Term Debt	—	(130,000)
Payments of Capital Lease Obligations	(13,703)	(12,440)
Payment of Debt Issue/Retirement Costs	—	(2,920)
Contribution from Parent	—	180,000
Other, Net	(4,028)	898
Net Cash Flows—Financing Activities	(17,731)	249,557
Net Increase (Decrease) in Cash and Cash Equivalents	(16,839)	29,365

Cash and Cash Equivalents, Beginning of Period	55,684	74,170
Cash and Cash Equivalents, End of Period	$38,845	$103,535

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

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TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in thousands)

	June 30, 2016	December 31, 2015
ASSETS		
Utility Plant		
Plant in Service	$5,629,448	$5,618,435
Utility Plant Under Capital Leases	131,705	131,705
Construction Work in Progress	119,717	102,028
Total Utility Plant	5,880,870	5,852,168
Accumulated Depreciation and Amortization	(2,195,490)	(2,194,301)
Accumulated Amortization of Capital Lease Assets	(102,075)	(99,638)
Total Utility Plant, Net	3,583,305	3,558,229
Investments and Other Property	40,369	39,569
Current Assets		
Cash and Cash Equivalents	38,845	55,684
Accounts Receivable, Net	158,036	136,682
Fuel Inventory	32,184	34,600
Materials and Supplies	91,737	94,003
Regulatory Assets	55,787	51,841
Derivative Instruments	5,019	1,808
Assets Held for Sale, Net	21,550	21,550
Other	17,642	25,904
Total Current Assets	420,800	422,072
Regulatory and Other Assets		
Regulatory Assets	213,403	212,312
Derivative Instruments	986	430
Other	34,824	16,866
Total Regulatory and Other Assets	249,213	229,608
Total Assets	$4,293,687	$4,249,478

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

(Continued)

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in thousands)

	June 30, 2016	December 31, 2015
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity:		
Common Stock (No Par Value, 75,000 Shares Authorized, 32,139 Shares Outstanding at June 30, 2016 and December 31, 2015)	$1,296,539	$1,296,539
Capital Stock Expense	(6,357)	(6,357)
Retained Earnings	229,151	189,317
Accumulated Other Comprehensive Loss	(4,313)	(4,564)
Total Common Stock Equity	1,515,020	1,474,935
Preferred Stock (No Par Value, 1,000 Shares Authorized, None Outstanding at June 30, 2016 and December 31, 2015)	—	—
Capital Lease Obligations	39,658	55,324
Long-Term Debt, Net	1,452,396	1,451,720
Total Capitalization	3,007,074	2,981,979
Current Liabilities		
Current Obligations Under Capital Leases	15,636	14,114
Accounts Payable	80,292	86,274
Accrued Taxes Other than Income Taxes	39,960	37,577
Accrued Employee Expenses	20,961	27,718
Accrued Interest	14,440	14,246
Regulatory Liabilities	68,474	53,077
Customer Deposits	21,008	20,349
Derivative Instruments	5,513	12,174
Other	22,668	7,533
Total Current Liabilities	288,952	273,062
Regulatory and Other Liabilities		
Deferred Income Taxes, Net	479,053	468,024
Regulatory Liabilities	304,512	307,286
Pension and Other Postretirement Benefits	119,126	120,336
Derivative Instruments	2,354	4,067
Other	92,616	94,724
Total Regulatory and Other Liabilities	997,661	994,437
Commitments and Contingencies		
Total Capitalization and Other Liabilities	$4,293,687	$4,249,478

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 at December 31, 2014	$1,116,539	$(6,357)	$111,523	$ (5,926)	$ 1,215,779
Net Income			47,255		47,255
Other Comprehensive Income (Loss), Net of Tax				576	576
Contribution from Parent	180,000				180,000
Balances at June 30, 2015	$1,296,539	$(6,357)	$158,778	$ (5,350)	$ 1,443,610
	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances at December 31, 2015	$1,296,539	$(6,357)	$189,317	$ (4,564)	$ 1,474,935
Net Income			39,834		39,834
Other Comprehensive Income (Loss), Net of Tax				251	251
Balances at June 30, 2016	$1,296,539	$(6,357)	$229,151	$ (4,313)	$ 1,515,020

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION
TEP is a regulated utility that generates, transmits, and distributes electricity to approximately 419,000 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).
References in these notes to "we" and "our" are to TEP.
BASIS OF PRESENTATION
We prepared our condensed consolidated financial statements according to 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 generating stations 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 our proportionate share of the operating costs associated with these facilities is included in the Condensed Consolidated Statements of Income. 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 our 2015 Annual Report on Form 10-K.
The condensed consolidated financial statements are unaudited, but, in management's opinion, include all 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, our 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.

NOTE 2. REGULATORY MATTERS
The Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC) each regulate portions of the 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.
2015 RATE CASE
In November 2015, TEP filed a general rate case with the ACC based on a test year ended June 30, 2015 (2015 Rate Case). Hearings before an administrative law judge are scheduled to begin in August 2016. The filing requests that new rates be implemented by January 1, 2017.
The key provisions of TEP's general rate case include:
- a Base Rate increase of $110 million, or 12%, compared with adjusted test year revenues;
- a 7.34% return on original cost rate base of $2.1 billion;
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of the San Juan Generating Station (San Juan) Unit 2 and the coal handling facilities at the H. Wilson Sundt Generating Station (Sundt) due to early retirement;
- a request for authority to begin using the Third-Party Owners' portion of Springerville Generating Station (Springerville) Unit 1 that is available to TEP for dispatch to serve retail customers' needs and to recover the related operating costs through the Purchased Power and Fuel Adjustment Clause (PPFAC); and
- rate design changes that would reduce the reliance on volumetric sales to recover fixed costs and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric

service.

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TEP cannot predict the outcome of this proceeding or whether its rate request will be adopted by the ACC in whole or in part.

COST RECOVERY MECHANISMS

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

Purchased Power and Fuel Adjustment Clause

TEP's PPFAC rate is adjusted annually each April 1st and goes into effect for the subsequent 12-month period unless modified by the ACC. The PPFAC rate includes: (i) a forward component which is calculated by taking the difference between forecasted fuel and purchased power costs and the amount of those costs established in Retail Rates; and (ii) a true-up component that reconciles the difference between actual costs and those recovered in the preceding 12-month period.

The table below presents TEP's PPFAC rates approved by the ACC:

Period	Cents per kWh
May 2016 through March 2017 (1)	0.15
April 2015 through April 2016	0.68
October 2014 through March 2015 (2)	0.50

(1) In April 2016, the ACC approved the PPFAC rate adjustment effective May 2016.

(2) The ACC approved a new rate effective October 2014.

Renewable Energy Standards

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 distributed generation accounting for 30% of the annual renewable energy requirement. Arizona utilities must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge until such costs are reflected in TEP’s Base Rates.

In May 2016, the ACC approved TEP's 2016 RES implementation plan that included a budget of $57 million, which will be partially offset by applying approximately $9 million of previously recovered carryover funds. TEP will recover the remaining $48 million through the RES surcharge. The budget will fund the following: (i) the above market cost of renewable energy purchases; (ii) previously awarded performance-based incentives for customer installed distributed generation; (iii) depreciation and a return on TEP's investments in company-owned solar projects; and (iv) various other program costs. The ACC deferred its decision on two proposals related to TEP's utility-owned rooftop solar and community solar projects. As a result, TEP is pursuing approval of these programs and related tariffs in the 2015 Rate Case.

The percentage of retail kilowatt-hour (kWh) sales attributable to the 2015 RES renewable energy requirement was 8.6%, which exceeded the overall 2015 requirement of 5.0%. TEP expects to meet the 2016 requirement of 6.0% of retail kWh sales. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain distributed generation renewable energy credits, which are used to demonstrate compliance with the distributed generation requirement, the company has requested, and the ACC has approved, a waiver of the 2016 residential distributed generation RES incremental requirement. In addition to the 2016 annual waiver, the ACC granted a waiver to TEP for the 2017 calendar year.

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 for a DSM surcharge for regulated utilities to recover from retail customers the costs to implement DSM programs as well as an annual performance incentive. TEP records its annual DSM performance incentive in the first quarter of each year, with $2 million recorded in 2016 and

$3 million in 2015 related to performance in each respective prior calendar year. 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. Under the 2016 plan, TEP will recover approximately $14 million from retail customers and will offer customers new and existing DSM programs. Energy savings realized through the programs will count toward the EE Standards and the associated lost revenue will be partially recovered through the Lost Fixed Cost Recovery (LFCR) mechanism.

Lost Fixed Cost Recovery Mechanism

The LFCR mechanism provides 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 distributed generation targets. 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 file an annual LFCR adjustment request with the ACC to recover the LFCR revenues recognized in the prior year. The recovery is subject to a year-over-year cap of 1% of TEP's applicable retail revenues.

TEP recorded a regulatory asset and recognized LFCR revenues of $4 million and $9 million in the three and six months ended June 30, 2016, respectively. TEP recorded $3 million and $5 million in the three and six months ended June 30, 2015, respectively. LFCR revenues are included in Retail Revenues on the Condensed Consolidated Statements of Income.

Appellate Review of Rate Decisions

In a 2015 appellate challenge to two ACC rate decisions regarding a water company, the Arizona Court of Appeals considered the issue of how the ACC should determine a utility’s “fair value,” as specified in the Arizona Constitution, in connection with authorizing recovery of costs through rate adjustors outside of a rate case. The Court reversed the ACC’s method of finding fair value in that case and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. In February 2016, the Arizona Supreme Court granted the ACC’s request for review of this decision. In March 2016, the Supreme Court heard oral arguments on this matter. If the Supreme Court upholds the decision without modification, certain TEP rate adjustors may be negatively affected which could have a significant impact on TEP’s ability to recover certain costs between rate cases. TEP filed a brief in support of the ACC’s petition to the Supreme Court for review of the Court of Appeals’ decision, but cannot predict the outcome of this matter.

FERC MATTERS

In April 2016, the FERC issued an order (FERC Refund Order) relating to certain late-filed transmission service agreements (TSAs), which directed TEP to issue time value refunds to the relevant counterparties to these TSAs, in an amount up to $13 million. See Note 5 for additional information related to FERC compliance associated with transmission contracts.

REGULATORY ASSETS AND LIABILITIES

Regulatory assets are either being collected or expected to be collected through Retail Rates. With the exception of the Third-Party Owners' share of the Springerville Unit 1 Leasehold Improvements and Sundt Coal Handling Facilities, we do not earn a return on regulatory assets. Regulatory liabilities represent items that we either expect to pay to customers through billing reductions in future periods or plan to use for the purpose for which they were collected from customers. With the exception of over-recovered PPFAC costs, TEP does not pay or accrue a return on regulatory liabilities.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The regulatory assets and liabilities recorded in the Condensed Consolidated Balance Sheets are summarized in the table below:

(in millions)	Remaining Recovery Period (years)	June 30, 2016	December 31, 2015
Regulatory Assets			
Pension and Other Postretirement Benefits	Various	$ 116	$ 120
Final Mine Reclamation and Retiree Health Care Costs (1)	21	30	28
Property Tax Deferrals	1	22	21
Income Taxes Recoverable through Future Rates	Various	22	26
Lost Fixed Cost Recovery	1	21	16
Springerville Unit 1 Leasehold Improvements - Third-Party Owners (2)	7	19	21
Sundt Coal Handling Facilities (3)	Plant Life	17	—
Derivatives (Note 8)	3	3	12
Other Regulatory Assets	Various	19	20
Total Regulatory Assets		269	264
Less Current Portion	1	56	52
Total Non-Current Regulatory Assets		$ 213	$ 212
Regulatory Liabilities			
Net Cost of Removal for Interim Retirements (4)	Various	$263	$264
Purchased Power and Fuel Adjustment Clause	1	34	18
Deferred Investment Tax Credits	Various	32	32
Renewable Energy Standard	Various	25	25
Other Regulatory Liabilities	Various	19	21
Total Regulatory Liabilities		373	360
Less Current Portion	1	68	53
Total Non-Current Regulatory Liabilities		$305	$307

(1) Final Mine Reclamation and Retiree Health Care Costs are recognized at future value. TEP will fully recover these costs through the PPFAC when paid. The majority of our final mine reclamation costs are expected to occur through 2037.

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

(3) In June 2014, the Environmental Protection Agency (EPA) issued a final rule that would require TEP to either: (i) install, by mid-2017, Selective Non-Catalytic Reduction (SNCR) and dry sorbent injection if Sundt Unit 4 continues to use coal as a fuel source; or (ii) permanently eliminate coal as a fuel source as a better-than-Best Available Retrofit Technology (BART) alternative by the end of 2017. In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source, and transferred the NBV of the Sundt Coal Handling Facilities to a regulatory asset. Consistent with the 2013 Rate Order, TEP has requested authorization from the ACC to apply excess depreciation reserves against the unrecovered NBV in its 2015 Rate Case.

(4) Net Cost of Removal for Interim Retirements represents an estimate of the cost of future asset retirement obligations (ARO) net of salvage value. These are amounts collected through revenue for the net cost of removal of interim retirements for transmission, distribution, generation plant, and general and intangible plant which are not yet expended.

NOTE 3. RELATED PARTY TRANSACTIONS

TEP engages in various transactions with Fortis, UNS Energy, and its affiliated subsidiaries including UniSource Energy Services, Inc. (UES), 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2016	December 31, 2015
Receivables from Related Parties		
UNS Electric	$ 4	$ 6
UNS Gas	1	1
Total Due from Related Parties	$ 5	$ 7
Payables to Related Parties		
SES	$ 2	$ 2
UNS Energy	1	2
UNS Electric	—	2
Total Due to Related Parties	$ 3	$ 6

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2016	2015	2016	2015
Goods and Services Provided by TEP to Affiliates				
Transmission Revenues - UNS Electric (1)	$ 2	$ 2	$ 3	$ 3
Wholesale Revenues - UNS Electric (1)	—	—	—	1
Control Area Services - UNS Electric (2)	1	—	1	1
Common Costs - UNS Energy Affiliates (3)	4	3	7	6
Goods and Services Provided by Affiliates to TEP				
Wholesale Revenues - UNS Electric (1)	$ —	$ —	$ —	$ 1
Supplemental Workforce - SES (4)	3	4	7	8
Corporate Services - UNS Energy (5)	2	1	4	2
Corporate Services - UNS Energy Affiliates (6)	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 deemed reasonable by management.

(5) Costs for corporate services at UNS Energy include Fortis management fees, legal fees, and audit fees which 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. For the three and six months ended June 30, 2016, these costs included approximately $2 million and $4 million, respectively in

Fortis management fees. For the three and six months ended June 30, 2015, Fortis management fees were $1 million and $2 million, 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.

DIVIDEND PAID

TEP did not declare or pay dividends in the first six months of 2016 or 2015. On July 27, 2016, TEP declared and paid $20 million in dividends to UNS Energy.

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NOTE 4. DEBT, CREDIT FACILITIES, AND CAPITAL LEASE OBLIGATIONS

There have been no significant changes to our debt, credit facilities, or capital lease obligations from those reported in our 2015 Annual Report on Form 10-K, except as noted below.

CAPITAL LEASE OBLIGATIONS

Springerville Coal Handling Facilities

In April 2015, upon the expiration of the lease term, TEP purchased an undivided ownership interest in the coal handling facilities at Springerville used by all four Springerville units (Springerville Coal Handling Facilities). With the completion of this purchase, Tri-State Generation and Transmission Association, Inc. (Tri-State) was obligated to either: (i) buy a 17.05% undivided interest in the facilities for approximately $24 million; or (ii) continue to make payments to TEP for the use of the facilities. In March 2016, Tri-State notified TEP that it was exercising its option to purchase the undivided interest in the facilities. The Tri-State purchase is expected to close by the end of 2016. At June 30, 2016, Tri-State's 17.05% undivided interest in the Springerville Coal Handling Facilities is classified as Assets Held for Sale on the Condensed Consolidated Balance Sheets.

COVENANT COMPLIANCE

At June 30, 2016, we were in compliance with the terms of our credit and long-term debt agreements.

NOTE 5. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

In addition to those reported in our 2015 Annual Report on Form 10-K, TEP entered into the following long-term commitments through June 30, 2016:

(in millions)	2016	2017	2018	2019	2020	Thereafter	Total
Fuel, Including Transportation	$ 21	$ 23	$ 24	$ 24	$ 23	$ 22	$ 137
Transmission	2	4	4	4	4	3	21
Renewable Power Purchase Agreements	3	3	3	3	3	43	58
Total Purchase Commitments	$ 26	$ 30	$ 31	$ 31	$ 30	$ 68	$ 216

TEP's transmission and fuel costs, including transportation, are recoverable from customers through the PPFAC mechanism. A portion of the cost of renewable energy is recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. See Note 2 for information on ACC approved cost recovery mechanisms.

Fuel, Including Transportation

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

In January 2016, the existing coal sale agreement for San Juan terminated and a new Coal Supply Agreement (CSA) became effective. The new CSA is between San Juan Coal Company (SJCC) and Public Service Company of New Mexico (PNM) and continues through June 2022. TEP is not a party to the new CSA, but has minimum purchase obligations under restructured ownership agreements at San Juan.

In April 2016, Peabody Energy Corp. (Peabody) filed for reorganization under Chapter 11 of the Bankruptcy Code. TEP has existing contracts with Peabody to supply coal from the El Segundo and Lee Ranch mines to Springerville and from the Kayenta mine to Navajo Generating Station (Navajo). TEP has continued to receive its contracted coal as planned and has sufficient access to coal inventory for the near future. TEP cannot currently predict the outcome of this matter or the range of its potential impact on TEP's coal supply from Peabody.

Transmission

TEP has agreements with other utilities to purchase transmission services over lines that are part of the Western Interconnection, a regional grid in the United States. These contracts expire in various years between 2017 and 2028.

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In June 2016, TEP entered into a new firm point-to-point transmission service agreement. The service agreement has a start date of August 2016 and expires in July 2021.

Renewable Power Purchase Agreements

TEP enters into long-term renewable Power Purchase Agreements (PPA) which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. In March 2016, one of these facilities achieved commercial operation. The PPA expires in February 2036. While TEP is not required to make payments under the agreement if power is not delivered, estimated future payments are included in the table above.

TEP's long-term renewable PPAs effectively transfer commodity price risk to TEP 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 Variable Interest Entities (VIEs). TEP reconsiders whether it is a primary beneficiary of the VIEs on a quarterly basis.

At June 30, 2016, the carrying amount of assets and liabilities in our Condensed Consolidated Balance Sheets that relate to our variable interests under long-term PPAs are predominantly related to working capital accounts and generally represent the amounts owed by TEP for the deliveries associated with the current billing cycle. Our maximum exposure to loss is limited to the cost of replacing the power if the providers do not meet the production guarantee. However, our exposure is mitigated as we would likely recover these costs through cost recovery mechanisms.

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 does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. TEP is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties, and other costs in substantial amounts and are described below.

Claims Related to Springerville Generating Station Unit 1

On February 29, 2016, TEP entered into an agreement with the Third-Party Owners for the settlement and release of asserted claims and the purchase and sale of beneficial interests in Springerville Unit 1 (Agreement). The Agreement provides that: (i) TEP will purchase the Third-Party Owners’ 50.5% undivided interest in Springerville Unit 1 for $85 million; and (ii) the Third-Party Owners will pay TEP $12.5 million for operating costs related to Springerville Unit 1 incurred on behalf of the Third-Party Owners. Upon completion of the purchase, all outstanding disputes and pending litigation and arbitration proceedings between TEP and the Third-Party Owners will be dismissed with prejudice.

The purchase of the Third-Party Owners' undivided interest in Springerville Unit 1 is subject to, among other things, approval from the FERC and satisfaction of other customary closing conditions. TEP expects the purchase to close in the third quarter of 2016. However, there is no assurance that the settlement will be finalized or that the litigation will not continue. Therefore, at this time TEP cannot predict the outcome of the claims relating to Springerville Unit 1, and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time. Should the litigation matters continue, TEP intends to continue vigorously defending itself against the claims asserted by the Third-Party Owners and to continue vigorously pursuing the claims it has asserted against the Owner Trustees and Co-Trustees.

The following is the chronological history of the outstanding disputes and pending litigation and arbitration proceedings between TEP and the Third-Party Owners.

In November 2014, the Springerville Unit 1 Third-Party Owners filed a complaint (FERC Action) against TEP at the FERC alleging that TEP had not agreed to wheel power and energy for the Third-Party Owners in the manner specified in the existing Springerville Unit 1 facility support agreement between TEP and the Third-Party Owners and for the cost specified by the Third-Party Owners. The Third-Party Owners requested an order from the FERC requiring such wheeling of the Third-Party Owners’ energy from their Springerville Unit 1 interests beginning in January 2015 to the Palo Verde switchyard and for the price specified by the Third-Party Owners. In February 2015, the FERC issued an order denying the Third-Party Owners' complaint. In March 2015, the Third-Party Owners filed a request for rehearing in the FERC Action, which the FERC denied in October 2015. In December 2015, the Third-Party Owners appealed the FERC’s order denying the Third-Party Owners' complaint to the U.S. Court of Appeals for the Ninth Circuit. In December 2015, TEP filed an unopposed motion to intervene in the Ninth Circuit appeal.

In December 2014, the Third-Party Owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County (New York Action). In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged, and the court's subsequent ruling on the motions, the Third-Party Owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases and that TEP has breached the lease transaction documents by refusing to pay certain of the Third-Party Owners' claimed expenses. The third amended complaint seeks $71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The Third-Party Owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015, the Third-Party Owners filed a motion for summary judgment on their claim that TEP has failed to pay certain of the Third-Party Owners' claimed expenses.

In December 2014 and January 2015, Wilmington Trust Company, as Owner Trustees and Lessors under the leases of the Third-Party Owners, sent notices to TEP that alleged that TEP had defaulted under the Third-Party Owners' leases. The notices demanded that TEP pay liquidated damages totaling approximately $71 million. In letters to the Owner Trustees, TEP denied the allegations in the notices.

In April 2015, TEP filed a demand for arbitration with the American Arbitration Association (AAA) seeking an award of the Owner Trustees and Co-Trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015, the Third-Party Owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The Third-Party Owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the Third-Party Owners' fees and expenses. TEP and the Third-Party Owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015, the Third-Party Owners filed an amended arbitration demand adding claims that TEP has converted the Third-Party Owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. In October 2015, the arbitration panel granted TEP's motion for interim relief, ordering the Owner Trustees and Co-Trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners' motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling, when economical, the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 2015.

In November 2015, TEP filed a petition to confirm the interim arbitration order in the Supreme Court of the State of New York naming the Owner Trustee and Co-Trustee as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act. In December 2015, the Owner Trustees filed an answer to the petition and a cross-motion to vacate the interim arbitration order.

As of June 30, 2016, TEP has billed the Third-Party Owners approximately $35 million for their pro-rata share of Springerville Unit 1 expenses and $7 million for their pro-rata share of capital expenditures, none of which had been paid as of July 28, 2016.

Claims Related to San Juan Generating Station

Bureau of Land Management

In August 2013, the Bureau of Land Management (BLM) proposed regulations that, among other things, redefine the term "underground mine" to exclude high-wall mining operations and impose a higher surface mine coal royalty on high-wall mining. SJCC utilized high-wall mining techniques at its surface mines prior to beginning underground mining operations in January 2003. If the proposed regulations become effective, SJCC may be subject to additional royalties on coal delivered to San Juan between August 2000 and January 2003 totaling approximately $5 million of which TEP's proportionate share would approximate $1 million. TEP owns 50% of Units 1 and 2 at San Juan, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot predict the final outcome of the BLM's proposed regulations.

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 Office of Surface Mining (OSM) challenging federal administrative decisions affecting seven different mines in four states 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 fifteen claims for relief in the WEG

Petition, two concern SJCC's San Juan mine. WEG's allegations concerning the San Juan mine arise from the OSM administrative actions in 2008. WEG alleges various National Environmental Policy Act (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 seven 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. The motion also requests that the previously-granted mining plan modification approvals for the San Juan mine remain in effect and mining be allowed to continue during the completion of the EIS, and that the case be dismissed. SJCC joined in the motion. If WEG ultimately obtains the relief it has requested, such a ruling could require significant expenditures to reconfigure operations at the San Juan mine, impact the production of coal, and impact the economic viability of the San Juan mine and San Juan. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Claims Related to Four Corners Generating Station

New Mexico Taxation and Revenue Department

In May 2013, the New Mexico Taxation and Revenue Department (NMTRD) issued a notice of assessment for coal severance tax, penalties, and interest totaling $30 million to the coal supplier at Four Corners Generating Station (Four Corners). TEP's share of the assessment is $1 million based on our ownership percentage. In December 2013, the coal supplier and Four Corners' operating agent filed a claim contesting the validity of the assessment on behalf of the participants in Four Corners, who will be liable for their share of any resulting liabilities. In June 2015, the U.S. District Court for the District of New Mexico ruled in favor of the Four Corners' participants. The NMTRD filed an appeal of the decision in August 2015. In March 2016, the coal supplier at Four Corners reached a final settlement agreement with the NMTRD. TEP's share of the final settlement was less than $1 million.

Endangered Species Act

On April 20, 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Arizona against the OSM and other federal agencies under the Endangered Species Act (ESA) alleging that the OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the U.S. Department of the Interior's (DOI) review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. This review process also required separate environmental impact evaluations under the NEPA and culminated in the issuance of a Record of Decision justifying the agency action extending the life of Four Corners and the adjacent Navajo mine. In addition, the lawsuit alleges that these federal agencies violated both the ESA and the NEPA in providing the federal approvals necessary to extend operations at Four Corners and the 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. The defendants answered the complaint on July 8, 2016. Arizona Public Service Company (APS), the operator of Four Corners, filed a motion to intervene in this matter in July 2016. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Navajo Generating Station Lease Amendment

Navajo is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. The Navajo Nation signed a lease amendment in 2013 that would extend the lease from 2019 through 2044. The participants in

Navajo, including TEP, have not signed the lease amendment because certain participants have expressed an interest in discontinuing their participation in Navajo. Negotiations between the participants are ongoing, and all parties will likely agree to the terms. To become effective, this lease amendment must be signed by all of the participants, approved by the DOI, and is subject to environmental reviews. Once the lease amendment becomes effective, the participants will be responsible for additional lease costs from the date the Navajo Nation signed the lease amendment. TEP owns 7.5% of Navajo. In the first six months of 2016, TEP recorded additional estimated lease expense of $1 million with the expectation that the lease amendment will become effective. TEP's Condensed Consolidated Balance Sheets reflect a total lease amendment liability recorded in Regulatory and Other Liabilities—Other of $4 million at June 30, 2016 and $3 million at December 31, 2015.

Mine Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation mine costs related to coal mines that supply generating stations 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 $42 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. TEP's Condensed Consolidated Balance Sheets reflect a total liability related to reclamation of $24 million at June 30, 2016 and $25 million at December 31, 2015.

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 us 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, TEP self-reported to the FERC Office of Enforcement (OE) that TEP had not timely filed certain FERC-jurisdictional agreements. At that time, TEP conducted a comprehensive internal review of its compliance with the FERC filing requirements (Compliance Review), and made necessary compliance filings with the FERC Office of Energy Market Regulation. This included the filing of several TEP TSAs entered into between 2003 and 2015 that contained certain deviations from TEP’s standard form of service agreement. The results of the Compliance Review were reported to OE, which is still reviewing the matter.

In April 2016, the FERC issued the FERC Refund Order relating to the late-filed TSAs, which directs TEP to issue time value refunds to the relevant counterparties to these TSAs, in an amount up to $13 million. In March 2016, as a result of the FERC Refund Order, TEP accrued $13 million offsetting Wholesale Revenues on the Condensed Consolidated Statements of Income. As specified in the FERC Refund Order, TEP reviewed its calculations of the ordered refunds and determined the refund amount to be $3 million, which was paid to the relevant counterparties in June 2016. TEP filed a refund report with the FERC on July 8, 2016. The amount of refunds paid is subject to final approval by the FERC and may be modified if the FERC does not accept TEP’s refund report. The remaining accrued balance is reflected in Current Liabilities—Other at June 30, 2016.

In June 2016, to preserve its rights, TEP petitioned the D.C. Circuit Court of Appeals to review the FERC Refund Order. On July 11, 2016, TEP filed an unopposed motion to hold the appeal in abeyance, which the Court has since granted. The FERC could also impose civil penalties on TEP as a result of the OE's review of the Compliance Review. At this time, TEP cannot predict the outcome of these matters or the range of potential penalties, if any.

Performance Guarantees

TEP has joint participation agreements with participants at Navajo, San Juan, Four Corners, and the Luna Energy Facility (Luna). The participants in each of the generating stations, 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 generating capacity of the defaulting participant. At June 30, 2016, 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.

Environmental Matters

TEP is subject to federal, state, and local 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 consolidated financial results. TEP expects to recover the cost of environmental compliance from its ratepayers. TEP believes it is in material compliance with all applicable environmental laws and regulations.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 6. EMPLOYEE BENEFIT PLANS

Net periodic benefit plan cost includes the following components:

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended June 30,			
(in millions)	2016	2015	2016	2015
Service Cost	$3	$3	$1	$1
Interest Cost	3	4	1	1
Expected Return on Plan Assets	(6)	(6)	(1)	(1)
Amortization of Net Loss (Gain)	2	2	—	—
Net Periodic Benefit Cost	$2	$3	$1	$1
	Six Months Ended June 30,			
(in millions)	2016	2015	2016	2015
Service Cost	$6	$6	$2	$2
Interest Cost	7	8	1	2
Expected Return on Plan Assets	(12)	(12)	(1)	(1)
Amortization of Net Loss (Gain)	4	4	—	—
Net Periodic Benefit Cost	$5	$6	$2	$3

CONTRIBUTIONS

TEP contributed $2 million in the six months ended June 30, 2016 to the pension plans and expects to contribute a total of $8 million in 2016.

NOTE 7. 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)	2016	2015
Accrued Capital Expenditures	$11	$23
Net Cost of Removal of Interim Retirements [1]	—	(3)

(1) The non-cash net cost of removal of interim retirements represents an accrual for future AROs that does not impact earnings.

NOTE 8. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS

The following tables present, by level within the fair value hierarchy, TEP's assets and liabilities accounted for at fair value on a recurring basis. 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, 2016			
Assets				
Cash Equivalents[1]	$23	$—	$—	$23
Restricted Cash[1]	4	—	—	4
Energy Derivative Contracts - Regulatory Recovery[2]	—	2	—	2
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	4	4
Total Assets	27	2	4	33
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(4)	(1)	(5)
Interest Rate Swap[3]	—	(3)	—	(3)
Total Liabilities	—	(7)	(1)	(8)
Net Total Assets (Liabilities)	$27	$(5)	$3	$25
(in millions)	December 31, 2015			
Assets				
Cash Equivalents[1]	$33	$—	$—	$33
Restricted Cash[1]	4	—	—	4
Energy Derivative Contracts - Regulatory Recovery[2]	—	1	—	1
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	1	1
Total Assets	37	1	1	39
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(10)	(3)	(13)
Interest Rate Swap[3]	—	(3)	—	(3)
Total Liabilities	—	(13)	(3)	(16)
Net Total Assets (Liabilities)	$37	$(12)	$(2)	$23

(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 on the Condensed Consolidated Balance Sheets.

(2) Energy Contracts include gas swap agreements (Level 2), gas options (Level 3), and forward power purchase 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 LIBOR and is included in Derivative Instruments on the Condensed Consolidated Balance Sheets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All energy derivative contracts are subject to legally enforceable master netting arrangements to mitigate credit risk. We present derivatives on a gross basis in the Condensed Consolidated Balance Sheets. 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	Cash Collateral Received/Posted	Net Amount
	June 30, 2016			
Derivative Assets				
Energy Derivative Contracts	$6	$ 2	$ —	$ 4
Derivative Liabilities				
Energy Derivative Contracts	(5)	(2)	—	(3)
Interest Rate Swap	(3)	—	—	(3)
	December 31, 2015			
Derivative Assets				
Energy Derivative Contracts	$2	$1	$—	$1
Derivative Liabilities				
Energy Derivative Contracts	(13)	(1)	—	(12)
Interest Rate Swap	(3)	—	—	(3)

DERIVATIVE INSTRUMENTS

We enter into various derivative and non-derivative contracts to reduce our exposure to energy price risk associated with our gas and purchased power requirements. The objectives for entering into such contracts include: creating price stability; meeting load and reserve requirements; and reducing exposure to price volatility that may result from delayed recovery under the PPFAC.

We primarily apply the market approach for recurring fair value measurements. When we have observable inputs for substantially the full term of the asset or liability or use quoted prices in an inactive market, we categorize the instrument in Level 2. We categorize derivatives in Level 3 when we use an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers.

For both power and gas prices we obtain quotes from brokers, major market participants, exchanges, or industry publications, and rely on our own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe 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, we apply adjustments based on historical price curve relationships, transmission, and line losses.

We estimate the fair value of our gas options using a Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, interest rates, and forward price curves.

We also consider the impact of counterparty credit risk using current and historical default and recovery rates, as well as our own credit risk using credit default swap data.

The inputs and our 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. We review the assumptions underlying our price curves monthly.

Cash Flow Hedges

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

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

(in millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Capital Lease Interest Expense	$ —	$ —	$ 1	$ 1

At June 30, 2016, the total notional amount of our interest rate swap was $23 million.

Energy Derivative Contracts - Regulatory Recovery

We record unrealized gains and losses on energy purchase contracts that are recoverable through the PPFAC in 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:

(in millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$ 12	$ 8	$ 9	$ 2

Energy Derivative Contracts - No Regulatory Recovery

Forward contracts with long-term wholesale customers do not qualify for regulatory recovery. For these contracts that qualify as derivatives, we record unrealized gains and losses in the income statement, unless and until a normal purchase or normal sale election is made. The unrealized gains and losses on the long-term power trading contracts are recorded in the income statement, and 10% of any gains will be shared with ratepayers through the PPFAC, as realized.

Derivative Volumes

At June 30, 2016, we have energy contracts that will settle through 2019. The volumes associated with our energy contracts were as follows:

	June 30, 2016	December 31, 2015
Power Contracts GWh	3,832	1,752
Gas Contracts GBtu	13,601	17,214

Level 3 Fair Value Measurements

The following table provides quantitative information regarding significant unobservable inputs in TEP’s Level 3 fair value measurements:

(in millions)	Valuation Approach	Fair Value of Assets	Fair Value of Liabilities	Unobservable Inputs	Range of Unobservable Input	
	June 30, 2016					
Forward Power Contracts	Market approach	$4	$ (1)	Market price per MWh	$ 21.40	$ 36.40
Level 3 Energy Contracts		$4	$ (1)			
	December 31, 2015					
Forward Power Contracts	Market approach	$ 1	$ (2)	Market price per MWh	$ 19.20	$ 31.35
Gas Option Contracts	Option model	—	(1)		$ 2.17	$ 2.69

			Market price per MMBtu		
			Gas volatility	31.0 %	58.3 %
Level 3 Energy Contracts	$ 1	$ (3)			

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

(in millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Beginning of Period	$(3)	$(12)	$(2)	$(9)
Gains (Losses) Recorded to: (1)				
Regulatory Assets or Liabilities – Derivative Instruments	3	2	2	—
Wholesale Revenues	3	3	3	3
Settlements	—	3	—	2
End of Period	$3	$(4)	$3	$(4)

(1) Includes gains (losses) attributable to the change in unrealized gains (losses) relating to assets (liabilities) still held at the end of the period of $6 million for both the three months ended June 30, 2016 and 2015 and $6 million and $3 million, for the six months ended June 30, 2016 and 2015, respectively.

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. We enter into contracts for the physical delivery of energy and 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.

We have 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: exposures in excess of unsecured credit limits; credit rating downgrades; or a failure to meet certain financial ratios. In the event that such credit events were to occur, we, or our counterparties, would have to provide certain credit enhancements in the form of cash, a Letter of Credit (LOC), or other acceptable security to collateralize exposure beyond the allowed amounts.

We consider 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 allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts.

Material adverse changes could trigger credit risk-related contingent features. At June 30, 2016, 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 $15 million, compared with $20 million at December 31, 2015. At June 30, 2016, TEP had no LOCs as credit enhancements with its counterparties. If the credit risk contingent features were triggered on June 30, 2016, TEP would have been required to post an additional $15 million of collateral of which $13 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. We use the following methods and assumptions for estimating the fair value of our financial instruments:

- Borrowings under revolving credit facilities approximate the fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For long-term debt, we use quoted market prices, when available, or calculate the present value of remaining cash flows at the balance sheet date. When calculating present value, we use current market rates for bonds with similar characteristics such as credit rating and time-to-maturity. We consider the principal amounts of variable rate debt

outstanding to be reasonable estimates of the fair value. We also incorporate the impact of our own credit risk using a credit default swap rate.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(in millions)	Fair Value Hierarchy	Face Value June 30, 2016	Face Value December 31, 2015	Fair Value June 30, 2016	Fair Value December 31, 2015
Liabilities					
Long-Term Debt, including Current Maturities	Level 2	$1,466	$ 1,466	$1,541	$ 1,529

NOTE 9. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

We consider the applicability and impact of all Accounting Standards 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 determined to be either not applicable or are expected to have minimal impact on our consolidated financial position, results of operations, or disclosures.

REVENUE FROM CONTRACTS WITH CUSTOMERS

In May 2014, the FASB issued an accounting standards update that will eliminate the transaction and industry-specific revenue recognition guidance under current U.S. GAAP and replace it with a principles based approach for determining revenue recognition. The revenue standard requires entities to apply the guidance retrospectively or recognize the cumulative effect of initially applying the guidance as an adjustment to the opening balance of retained earnings supplemented by additional disclosures. In July 2015, the FASB voted to defer the effective date of the revenue recognition standard by one year. We are required to adopt the new guidance for annual and interim periods beginning January 1, 2018.

Retail sales of electricity based on regulator-approved tariff rates represent TEP's primary source of revenue. While it is expected that tariff-based sales to regulated customers are within the scope of the new standard, this question is being reviewed by the AICPA Financial Reporting Executive Committee. TEP is in the process of assessing its performance obligations in its wholesale contracts and identifying other contracts with customers.

CLASSIFICATION AND MEASUREMENT OF FINANCIAL INSTRUMENTS

In January 2016, the FASB amended the guidance on the classification and measurement of financial instruments. Most notably, the new accounting standards update requires the following:

- all equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings; however, entities will be able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; and
- financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category and form of financial asset.

TEP is required to adopt the new guidance for annual and interim periods beginning January 1, 2018. TEP is evaluating the impact of this guidance to our financial statements and disclosures.

LEASES

In February 2016, the FASB issued an accounting standards update that will require the recognition of leased assets and liabilities by lessees for those leases classified as operating leases under previous 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 our financial statements and disclosures.

SHARE-BASED COMPENSATION

In March 2016, the FASB issued an accounting standards update that simplifies some provisions in stock compensation accounting. The update involves several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendment:

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- requires that all excess tax benefits and tax deficiencies for share-based payment awards be recognized as income tax expense or benefit in the income statement;
- specifies presentation on the statement of cash flows, and
- requires an accounting policy election to estimate the number of awards that are expected to vest or account for forfeitures when they occur.

TEP is required to adopt the new guidance for annual and interim periods beginning January 1, 2017; early adoption is permitted. TEP is evaluating the impact of this update to our financial statements and disclosures.

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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 during the first six months of 2016 compared with the same period of 2015;
- factors affecting our results and outlook;
- liquidity and capital resources including contractual obligations and environmental matters;
- critical accounting policies and estimates; and
- recent accounting pronouncements.

Management's Discussion and Analysis includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures. The non-GAAP financial measures 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 2015 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:

- achieving a constructive outcome in our pending rate case proceeding that provides TEP recovery of its full cost of service and an opportunity to earn an appropriate return on its rate base investments, updated rates to provide more accurate price signals and a more equitable allocation of costs to TEP's customers, and enables TEP to continue to provide safe and reliable service.
- continuing to focus on our long-term generation resource 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, optimizing the performance of our existing utility infrastructure, and maintaining financial strength.
- developing strategic responses to new environmental regulations and potential new legislation, including new carbon emission standards to reduce greenhouse gas emissions from existing power plants. We are evaluating TEP's existing mix of generation resources and defining steps to achieve environmental objectives that protect the financial stability of our utility business and the interests of our customers.
- strengthening the underlying financial condition of TEP by achieving constructive regulatory outcomes, strengthening our capital structure, sustaining our credit ratings, and promoting economic development in our service territory.
- focusing on our core utility business through operational excellence, investing in utility rate base, emphasizing customer service, and maintaining a strong community presence.

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2016 Operational and Financial Highlights

The first six months of 2016 included the following notable items:

- In February 2016, TEP entered into an agreement with the Third-Party Owners for the settlement and release of asserted claims and the purchase by TEP of the Third-Party Owners' 50.5% undivided interest in Springerville Unit 1 for $85 million. The Third-Party Owners will pay TEP $12.5 million for operating costs related to Springerville Unit 1 incurred on behalf of the Third-Party Owners.
- In March 2016, Tri-State notified TEP that it was exercising its option to purchase a 17.05% undivided interest in the Springerville Coal Handling Facilities for approximately $24 million. The Tri-State purchase is expected to close by the end of 2016.
- In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source as a better-than-BART alternative at Sundt by no later than December 2017.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations during the first six months of 2016 compared with the same period in 2015. The significant items affecting net income are presented on an after-tax basis.

The second quarter of 2016 compared with the second quarter of 2015

TEP reported net income of $41 million in the second quarter 2016 compared with $38 million from the second quarter 2015. The increase of $3 million, or 7.9%, was primarily due to:

- $3 million in higher net income as a result of a reduction in the valuation allowance for deferred tax assets based on an increase in projected taxable income; and
- $1 million in higher LFCR revenues.

The increase was partially offset by $2 million in higher operations and maintenance expense primarily from increases in maintenance expense due to planned generation outages.

The first six months of 2016 compared with the first six months of 2015

TEP reported net income of $40 million in the first six months of 2016 compared with net income of $47 million from the first six months of 2015. The decrease of $7 million, or 14.9%, was primarily due to:

- $8 million in FERC ordered refunds associated with late-filed TSAs; and
- $5 million in higher operations and maintenance expense resulting primarily from increases in maintenance expense due to planned generation outages, outside services, and employee wages and benefits.

The decrease was partially offset by:

- $3 million in higher net income as a result of a reduction in the valuation allowance for deferred tax assets based on an increase in projected taxable income; and
- $3 million from higher retail sales as a result of favorable weather conditions and an increase in LFCR revenues.

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Retail Sales and Revenues

Retail Revenues were $256 million in the second quarter of 2016 compared with $264 million in the second quarter of 2015. Retail Margin Revenues (Non-GAAP) were $164 million in the second quarter of 2016 compared with $163 million in the second quarter of 2015. The table below provides a summary of retail kWh sales, a reconciliation of Retail Margin Revenues to Retail Revenues, and weather data for the second quarter of 2016 and 2015:

	Three Months Ended June 30,		Increase (Decrease)	
	2016	2015	Amount	Percent
Retail Sales by Customer Class (kWh in millions)				
Residential	950	924	26	2.8 %
Commercial	566	564	2	0.4 %
Industrial	494	519	(25)	(4.8)%
Mining	247	278	(31)	(11.2)%
Public Authorities	7	8	(1)	(12.5)%
Total Retail Sales by Class	2,264	2,293	(29)	(1.3)%
Retail Revenues (in millions)				
Residential	$72	$70	$2	2.9 %
Commercial	51	51	—	— %
Industrial	26	27	(1)	(3.7)%
Mining	9	10	(1)	(10.0)%
Public Authorities	1	1	—	— %
Retail Margin Revenues by Class	159	159	—	— %
LFCR Revenues	4	3	1	33.3 %
Other Retail Margin Revenues	1	1	—	— %
Retail Margin Revenues (Non-GAAP) (1)	164	163	1	0.6 %
Fuel and Purchased Power Revenues	79	88	(9)	(10.2)%
DSM and RES Surcharge Revenues	13	13	—	— %
Total Retail Revenues (GAAP)	$256	$264	$(8)	(3.0)%
Average Retail Margin Rate by Class (cents / kWh) (2)				
Residential	7.58	7.58	—	— %
Commercial	9.01	9.04	(0.03)	(0.3)%
Industrial	5.26	5.20	0.06	1.2 %
Mining	3.64	3.60	0.04	1.1 %
Public Authorities	5.79	5.74	0.05	0.9 %
Average Retail Margin Rate by Class	7.02	6.93	0.09	1.3 %
Total Average Retail Margin Rate (3)	7.24	7.11	0.13	1.8 %
Average Fuel and Purchased Power Rate	3.49	3.84	(0.35)	(9.1)%
Average DSM and RES Surcharge Rate	0.57	0.57	—	— %
Total Average Retail Rate	11.30	11.52	(0.22)	(1.9)%
Weather Data				
Cooling Degree Days				
Actual	469	480	(11)	(2.3)%
10-year Average	472	479	*	*
Heating Degree Days				
Actual	23	19	4	21.1 %
10-year Average	42	41	*	*

*Not meaningful

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(1) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude: (i) revenues collected from retail customers that are directly offset by expenses recorded in other line items; and (ii) revenues collected from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information 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 and Other Retail Margin Revenues included in Retail Margin Revenues.

Retail Revenues were lower in the second quarter of 2016 when compared with the same period in 2015, primarily due to a decrease in the PPFAC rate partially offset by higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to an increase in LFCR revenues.

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Retail Revenues were $460 million in the second quarter of 2016 compared with $466 million in the second quarter of 2015. Retail Margin Revenues (Non-GAAP) were $292 million in the second quarter of 2016 compared with $288 million in the second quarter of 2015. The table below provides a summary of retail kWh sales, a reconciliation of Retail Margin Revenues to Retail Revenues, and weather data for the first six months of 2016 and 2015:

	Six Months Ended June 30,		Increase (Decrease)	
	2016	2015	Amount	Percent
Retail Sales by Customer Class (kWh in millions)				
Residential	1,647	1,604	43	2.7 %
Commercial	1,006	998	8	0.8 %
Industrial	947	982	(35)	(3.6)%
Mining	498	553	(55)	(9.9)%
Public Authorities	16	17	(1)	(5.9)%
Total Retail Sales by Class	4,114	4,154	(40)	(1.0)%
Retail Revenues (in millions)				
Residential	$125	$122	$3	2.5 %
Commercial	86	85	1	1.2 %
Industrial	50	50	—	— %
Mining	17	19	(2)	(10.5)%
Public Authorities	1	1	—	— %
Retail Margin Revenues by Class	279	277	2	0.7 %
LFCR Revenues	9	5	4	80.0 %
DSM Performance Bonus	2	3	(1)	(33.3)%
Other Retail Margin Revenues	2	3	(1)	(33.3)%
Retail Margin Revenues (Non-GAAP) [1]	292	288	4	1.4 %
Fuel and Purchased Power Revenues	145	154	(9)	(5.8)%
DSM and RES Surcharge Revenues	23	24	(1)	(4.2)%
Total Retail Revenues (GAAP)	$460	$466	$(6)	(1.3)%
Average Retail Margin Rate by Class (cents /kWh) [2]				
Residential	7.59	7.61	(0.02)	(0.3)%
Commercial	8.55	8.52	0.03	0.4 %
Industrial	5.28	5.09	0.19	3.7 %
Mining	3.41	3.44	(0.03)	(0.9)%
Public Authorities	5.64	5.62	0.02	0.4 %
Average Retail Margin Rate by Class	6.78	6.67	0.11	1.6 %
Total Average Retail Margin Rate [3]	7.10	6.93	0.17	2.5 %
Average Fuel and Purchased Power Rate	3.52	3.71	(0.19)	(5.1)%
Average DSM and RES Rate	0.56	0.58	(0.02)	(3.4)%
Total Average Retail Rate	11.18	11.22	(0.04)	(0.4)%
Weather Data				
Cooling Degree Days				
Actual	469	483	(14)	(2.9)%
10-year Average	473	480	*	*
Heating Degree Days				
Actual	629	452	177	39.2 %
10-year Average	773	784	*	*

* Not meaningful

(1)

Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues,

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which is determined in accordance with GAAP. Retail Margin Revenues exclude: (i) revenues collected from retail customers that are directly offset by expenses recorded in other line items; and (ii) revenues collected from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information 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, DSM Performance Bonus, and Other Retail Margin Revenues included in Retail Margin Revenues.

Retail Revenues were lower in the first six months of 2016 when compared with the same period in 2015 primarily due to a decrease in the PPFAC rate offset by higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to an increase in residential sales resulting from favorable weather conditions and an increase in LFCR revenues.

Wholesale Revenues

(in millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Long-Term Wholesale Revenues	$10	$ 11	$16	$ 18
Short-Term Wholesale Revenues	16	29	30	57
Transmission Revenues	8	8	15	14
Transmission Refunds [1]	—	—	(13)	—
Total Wholesale Revenues	$34	$ 48	$48	$ 89

(1) FERC ordered TEP to make refunds associated with various late-filed TSAs for the time period during which rates were charged without FERC authorization. See Note 5 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information on the FERC order.

Wholesale Revenues decreased by $14 million, or 29.2%, in the second quarter of 2016 compared with the same period in 2015 primarily due to decreased volumes of short-term wholesale sales resulting from unfavorable market conditions.

Wholesale Revenues decreased by $41 million, or 46.1%, in the first six months of 2016 compared with the same period in 2015 primarily due to FERC ordered refunds associated with TSAs and decreased volumes of short-term wholesale sales resulting from unfavorable market conditions.

The majority of revenues from short-term wholesale sales is related to ACC jurisdictional assets and are returned to retail customers by crediting them against the fuel and purchased power costs eligible for recovery in the PPFAC.

Other Revenues

(in millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Springerville Units 3 and 4 Revenue [1]	$20	$ 22	$38	$ 45
Other Revenue	7	6	14	14
Total Other Revenues	$27	$ 28	$52	$ 59

(1) Represents revenues and reimbursements from Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, to TEP related to the operation of these plants.

Total Other Revenues include reimbursements related to Springerville Units 3 and 4; inter-company revenues from its affiliates, UNS Gas and UNS Electric, for corporate services provided by TEP; and miscellaneous service-related revenues such as rent on power pole attachments, damage claims, and customer late fees.

There were no significant changes in Other Revenue noted in the second quarter of 2016 when compared with the same periods in 2015.

Springerville Units 3 and 4 Revenue decreased in the first six months of 2016 when compared with the same period in 2015 primarily due to a decrease in reimbursements of O&M expenses resulting from lower generating output in 2016 and planned

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generation outages in 2015. There were no significant changes in Other Revenue noted in the first six months of 2016 when compared with the same periods in 2015.

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)	2016	2015	2016	2015
Coal-Fired Generation	1,965	2,186	$ 44	