TUCSON ELECTRIC POWER CO
Form 10-Q
November 02, 2018

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 September 30, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission File Number 1-5924
TUCSON ELECTRIC POWER COMPANY
(Exact name of registrant as specified in its charter)

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

88 East Broadway Boulevard, Tucson, AZ 85701
(Address of principal executive offices)(Zip Code)
Registrant's telephone number, including area code: (520) 571-4000
Former name, former address and former fiscal year, if changed since last report: N/A

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer o Accelerated Filer o Non-Accelerated Filer x Smaller Reporting Company o Emerging Growth Company o
If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x
All shares of outstanding common stock of Tucson Electric Power Company are held by its parent company, UNS Energy Corporation, which is an indirect, wholly-owned subsidiary of Fortis Inc. There were 32,139,434 shares of common stock, no par value, outstanding as of November 1, 2018.

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DEFINITIONS

The abbreviations and acronyms used in this Form 10-Q are defined below:

2010 Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2017 Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective on February 27, 2017
ABR	Alternate Base Rate
ACC	Arizona Corporation Commission
ACC Refund Order	An order issued by the ACC approving TEP’s proposal to return savings from the Company’s federal corporate income tax rate under the TCJA to its customers through a combination of a customer bill credit and a regulatory liability that reflects the deferral of the return of a portion of the savings
ASU	Accounting Standards Update
BART	Best Available Retrofit Technology
BBtu	Billion British thermal units
DG	Distributed Generation
DSM	Demand Side Management
EDIT	Excess Deferred Income Taxes
EE Standards	Energy Efficiency Standards
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FERC Refund Order	An order issued by the FERC directing TEP to either: (i) submit proposed revisions to its stated transmission rates or stated transmission revenue requirements to reflect the change in the federal corporate income tax rate as a result of the TCJA; or (ii) show cause why it should not be required to do so
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada, whose principal executive offices are located at Fortis Place, Suite 1100, 5 Springdale Street, St. John's, NL A1E 0E4
Four Corners	Four Corners Generating Station
GAAP	Generally Accepted Accounting Principles in the United States of America
Gila Acquisition	SRP entered into an agreement to acquire Gila River Units 1 and 2 from third-parties
Gila River	Gila River Generating Station
GWh	Gigawatt-hour(s)
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LIBOR	London Interbank Offered Rate
LOC	Letter(s) of Credit
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
NOI	Notice of Inquiry
Phase 2	Second phase of TEP's rate case proceedings originally filed November 2015
Phase 2 Order	ACC order establishing, among other things, an export rate that replaced net metering for excess solar generation
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
Regional Haze	Regulations promulgated by the EPA to improve visibility at national parks and wilderness areas

RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility recovery of its costs of providing services and an opportunity to earn a reasonable return on its investment

San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction
SES	Southwest Energy Solutions, Inc.
Springerville	Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
TCJA	On December 22, 2017, the Tax Cuts and Jobs Act was signed into law enacting significant changes to the Internal Revenue Code including a reduction in the federal corporate income tax rate from 35% to 21% effective for tax years beginning after 2017
TEP	Tucson Electric Power Company, the principal subsidiary of UNS Energy Corporation
Tolling PPA	A 20-year tolling PPA that TEP entered into in 2017 with SRP to purchase and receive all 550 MW of capacity, power, and ancillary services from Gila River Unit 2, which includes a three-year option to purchase the unit
TSA	Transmission Service Agreement
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy Corporation
UNS Energy	UNS Energy Corporation, the parent company of TEP, whose principal executive offices are located at 88 East Broadway Boulevard, Tucson, Arizona 85701
UNS Energy Affiliates	Affiliated subsidiaries of UNS Energy Corporation including UniSource Energy Services, Inc., UNS Electric, Inc., UNS Gas, Inc., and Southwest Energy Solutions, Inc.
UNS Gas	UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy Corporation
VIE	Variable Interest Entity

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

Forward-looking statements involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed therein. We express our estimates, expectations, beliefs, and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management’s estimates, expectations, beliefs, or projections will be achieved or accomplished. We have identified the following important factors that could cause actual results to differ materially from those discussed in our forward-looking statements. These may be in addition to other factors and matters discussed in: Part I, Item 1A. Risk Factors of our 2017 Form 10-K/A; 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: voter initiatives and state and federal regulatory and legislative decisions and actions, including changes in tax and energy policies; changes in, and compliance with, environmental laws and regulatory decisions and policies that could increase operating and capital costs, reduce generation facility output or accelerate generation facility retirements; regional economic and market conditions which could affect customer growth and energy usage; changes in energy consumption by retail customers; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets and bank markets; the performance of the stock market and a changing interest rate environment, which affect the value of our pension and other postretirement benefit plan assets and the related contribution requirements and expenses; the potential inability to make additions to our existing high voltage transmission system; unexpected increases in operations and maintenance expense; resolution of pending litigation matters; changes in accounting standards; changes in our critical accounting policies and estimates; the ongoing impact of mandated energy efficiency and distributed generation (DG) initiatives; changes to long-term contracts; the cost of fuel and power supplies; the ability to obtain coal from our suppliers; cyber-attacks, data breaches, or other challenges to our information security, including our operations and technology systems; the performance of TEP's generation facilities; and the impact of the Tax Cuts and Jobs Act (TCJA) on our financial condition and results of operations, including the assumptions we make relating thereto.

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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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Operating Revenues	$459,760	$417,210	$1,089,096	$1,037,736
Operating Expenses				
Fuel	115,534	91,754	246,427	218,226
Purchased Power	49,564	38,903	102,317	107,039
Transmission and Other PPFAC Recoverable Costs	14,367	10,285	34,067	27,167
Increase (Decrease) to Reflect PPFAC Recovery Treatment	3,681	(9,166)	9,087	(24,773)
Total Fuel and Purchased Power	183,146	131,776	391,898	327,659
Operations and Maintenance	89,319	89,862	265,920	256,493
Depreciation	39,929	38,302	118,223	114,667
Amortization	6,898	5,463	18,940	16,323
Taxes Other Than Income Taxes	14,321	13,549	42,800	40,329
Total Operating Expenses	333,613	278,952	837,781	755,471
Operating Income	126,147	138,258	251,315	282,265
Other Income (Expense)				
Interest Expense	(16,626)	(16,291)	(49,818)	(48,972)
Allowance For Borrowed Funds	757	525	2,150	1,645
Allowance For Equity Funds	2,113	1,353	5,290	4,145
Other, Net	1,702	255	2,957	8,562
Total Other Income (Expense)	(12,054)	(14,158)	(39,421)	(34,620)
Income Before Income Tax Expense	114,093	124,100	211,894	247,645
Income Tax Expense	19,120	42,100	35,521	83,951
Net Income	$94,973	$82,000	$176,373	$163,694

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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Comprehensive Income				
Net Income	$94,973	$82,000	$176,373	$163,694
Other Comprehensive Income				
Net Changes in Fair Value of Cash Flow Hedges:				
Net of Income Tax Expense of $26 and $79	78	121		
Net of Income Tax Expense of $99 and $212			297	336
Supplemental Executive Retirement Plan Adjustments:				
Net of Income Tax Expense of $39 and $44	117	69		
Net of Income Tax Expense of $118 and $130			349	209
Total Other Comprehensive Income, Net of Tax	195	190	646	545
Total Comprehensive Income	$95,168	$82,190	$177,019	$164,239

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)

	Nine Months Ended September 30, 2018	2017
Cash Flows from Operating Activities		
Net Income	$176,373	$163,694
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation Expense	118,223	114,667
Amortization Expense	18,940	16,323
Amortization of Debt Issuance Costs	1,747	1,763
Use of Renewable Energy Credits for Compliance	22,938	17,434
Deferred Income Taxes	48,056	83,954
Pension and Other Postretirement Benefits Expense	11,485	12,029
Pension and Other Postretirement Benefits Funding	(15,008)	(12,763)
Allowance for Equity Funds Used During Construction	(5,290)	(4,145)
FERC Transmission Refund Payable	—	(4,878)
Changes in Current Assets and Current Liabilities:		
Accounts Receivable	(57,815)	(59,016)
Materials, Supplies, and Fuel Inventory	3,749	452
Regulatory Assets	37	(2,407)
Accounts Payable and Accrued Charges	20,959	25,628
Income Taxes Receivable	(12,532)	—
Regulatory Liabilities	21,959	(10,258)
Other, Net	(1,713)	(5,108)
Net Cash Flows—Operating Activities	352,108	337,369
Cash Flows from Investing Activities		
Capital Expenditures	(273,398)	(215,826)
Purchase Intangibles, Renewable Energy Credits	(39,516)	(40,838)
Contributions in Aid of Construction	9,765	3,265
Net Cash Flows—Investing Activities	(303,149)	(253,399)
Cash Flows from Financing Activities		
Proceeds from Borrowings, Revolving Credit Facility	101,000	35,000
Repayments of Borrowings, Revolving Credit Facility	(121,000)	(35,000)
Dividend Paid to Parent	(40,000)	(35,000)
Payments of Capital Lease Obligations	(10,930)	(14,804)
Other, Net	(150)	641
Net Cash Flows—Financing Activities	(71,080)	(49,163)
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	(22,121)	34,807
Cash, Cash Equivalents, and Restricted Cash, Beginning of Period	49,501	43,325
Cash, Cash Equivalents, and Restricted Cash, End of Period	$27,380	$78,132

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

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

	September 30, 2018	December 31, 2017
ASSETS		
Utility Plant		
Plant in Service	$ 5,959,013	$ 5,780,805
Utility Plant Under Capital Leases	248,635	84,870
Construction Work in Progress	234,994	160,288
Total Utility Plant	6,442,642	6,025,963
Accumulated Depreciation and Amortization	(2,263,742)	(2,193,656)
Accumulated Amortization of Capital Lease Assets	(70,693)	(63,605)
Total Utility Plant, Net	4,108,207	3,768,702
Investments and Other Property	51,339	51,260
Current Assets		
Cash and Cash Equivalents	17,539	37,701
Accounts Receivable, Net	196,366	137,932
Fuel Inventory	18,666	25,059
Materials and Supplies	106,001	103,981
Regulatory Assets	110,329	93,960
Derivative Instruments	3,977	3,187
Other	26,650	10,777
Total Current Assets	479,528	412,597
Regulatory and Other Assets		
Regulatory Assets	293,627	293,551
Derivative Instruments	4,910	8,826
Other	68,576	55,313
Total Regulatory and Other Assets	367,113	357,690
Total Assets	$ 5,006,187	$ 4,590,249

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

(Continued)

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

	September 30, 2018	December 31, 2017
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity:		
Common Stock (No Par Value, 75,000,000 Shares Authorized, 32,139,434 Shares Outstanding as of September 30, 2018 and December 31, 2017)	$ 1,296,539	$ 1,296,539
Capital Stock Expense	(6,357)	(6,357)
Retained Earnings	517,327	380,076
Accumulated Other Comprehensive Loss	(6,458)	(6,226)
Total Common Stock Equity	1,801,051	1,664,032
Preferred Stock (No Par Value, 1,000,000 Shares Authorized, None Outstanding as of September 30, 2018 and December 31, 2017)	—	—
Capital Lease Obligations	181,571	28,519
Long-Term Debt, Net	1,318,509	1,354,423
Total Capitalization	3,301,131	3,046,974
Current Liabilities		
Current Maturities of Long-Term Debt	136,700	100,000
Borrowings Under Revolving Credit Facility	15,000	35,000
Capital Lease Obligations	10,713	10,749
Accounts Payable	130,396	97,367
Accrued Taxes Other than Income Taxes	62,960	40,706
Accrued Employee Expenses	25,346	30,929
Accrued Interest	14,815	14,750
Regulatory Liabilities	109,661	89,024
Customer Deposits	26,668	24,865
Derivative Instruments	23,822	10,667
Other	16,361	18,119
Total Current Liabilities	572,442	472,176
Regulatory and Other Liabilities		
Deferred Income Taxes, Net	364,452	300,258
Regulatory Liabilities	494,353	516,438
Pension and Other Postretirement Benefits	125,339	133,799
Derivative Instruments	24,218	17,907
Other	124,252	102,697
Total Regulatory and Other Liabilities	1,132,614	1,071,099
Commitments and Contingencies		
Total Capitalization and Other Liabilities	$ 5,006,187	$ 4,590,249

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

(Concluded)

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

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances as of December 31, 2017	$1,296,539	$(6,357)	$380,076	$ (6,226)	$ 1,664,032
Net Income			176,373		176,373
Other Comprehensive Income, Net of Tax				646	646
Dividend Declared to Parent			(40,000)		(40,000)
Adoption of ASU, Cumulative Effect Adjustment			878	(878)	—
Balances as of September 30, 2018	$1,296,539	$(6,357)	$517,327	$ (6,458)	$ 1,801,051

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances as of December 31, 2016	$1,296,539	$(6,357)	$273,408	$ (4,555)	$ 1,559,035
Net Income			163,694		163,694
Other Comprehensive Income, Net of Tax				545	545
Dividend Declared to Parent			(35,000)		(35,000)
Balances as of September 30, 2017	$1,296,539	$(6,357)	$402,102	$ (4,010)	$ 1,688,274

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

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION

TEP is a regulated utility that generates, transmits, and distributes electricity to approximately 425,000 retail customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. TEP is a wholly-owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly-owned subsidiary of Fortis Inc. (Fortis).

BASIS OF PRESENTATION

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

The Condensed Consolidated Financial Statements include the accounts of TEP and its subsidiaries. In the consolidation process, accounts of the parent and subsidiaries are combined and intercompany balances and transactions are eliminated. TEP jointly owns several generation and transmission facilities with both affiliated and non-affiliated entities. TEP's proportionate share of jointly-owned facilities is recorded in Utility Plant on the Condensed Consolidated Balance Sheets, and its proportionate share of the operating costs associated with these facilities is included in the 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 TEP's 2017 Annual Report on Form 10-K/A.

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

Certain amounts from prior periods have been reclassified to conform to the current period presentation. Most notably, TEP combined captions on the Condensed Consolidated Statements of Income by reclassifying similar line items into a single line item as follows:

(in thousands)	As Filed	Amount Reclassified	As Reclassified	As Filed	Amount Reclassified	As Reclassified
	Three Months Ended September 30, 2017			Nine Months Ended September 30, 2017		
Other Income (Deductions)						
Interest Income	$30	$ (30)	$ —	$556	$ (556)	$ —
Other Income	1,738	(1,738)	—	12,630	(12,630)	—
Other Expense	(1,072)	1,072	—	(2,609)	2,609	—
Appreciation in Value of Investments	912	(912)	—	2,130	(2,130)	—
Allowance For Equity Funds	—	1,353	1,353	—	4,145	4,145
Other, Net	—	255	255	—	8,562	8,562
Interest Expense						
Long-Term Debt	15,531	(15,531)	—	46,461	(46,461)	—
Capital Leases	613	(613)	—	1,941	(1,941)	—
Other Interest Expense	147	(147)	—	570	(570)	—
Interest Capitalized	(525)	525	—	(1,645)	1,645	—
Allowance For Borrowed Funds	—	(525)	(525)	—	(1,645)	(1,645)
Interest Expense	—	16,291	16,291	—	48,972	48,972

Variable Interest Entities

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

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

As of September 30, 2018, the carrying amount of assets and liabilities in the balance sheet that relates to variable interests under long-term PPAs is predominantly related to working capital accounts and generally represents the amounts owed by TEP for the deliveries associated with the current billing cycle. TEP's maximum exposure to loss is limited to the cost of replacing the power if the providers do not meet the production guarantee. However, the exposure to loss is mitigated as the Company would likely recover these costs through cost recovery mechanisms. See Note 2 for additional information related to cost recovery mechanisms.

Restricted Cash

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

	Nine Months Ended September 30,	
(in millions)	2018	2017
Cash and Cash Equivalents	$ 18	$ 70
Restricted Cash included in:		
Investments and Other Property	8	7
Current Assets—Other	1	1
Total Cash, Cash Equivalents, and Restricted Cash	$ 27	$ 78

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

ASSET RETIREMENT OBLIGATIONS

TEP records the fair value of a liability for a legal obligation to retire a long-lived tangible asset in the period in which the liability is incurred. The Asset Retirement Obligation (ARO) accrual is primarily related to generation and photovoltaic assets and is included in Regulatory and Other Liabilities—Other on the Condensed Consolidated Balance Sheets. The following table reconciles the beginning and ending aggregate carrying amounts of ARO accruals on the Condensed Consolidated Balance Sheets:

(in millions)	Asset Retirement Obligation
Balances as of December 31, 2017	$ 46
Liabilities Incurred (1)	8
Regulatory Deferral/Accretion Expense	1
Revisions to the Present Value of Estimated Cash Flows (2)	13
Balances as of September 30, 2018	$ 68

(1) Primarily related to closure of the ash landfill at Springerville Generating Station (Springerville).

(2) Primarily related to changes in expected cost estimates for closure of certain generation facilities.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers

Effective January 1, 2018, TEP adopted accounting guidance that requires recognition of revenue when a customer obtains control of promised goods or services in an amount that reflects the consideration to which the company expects to be entitled. The Company continues to recognize revenue for tariff-based sales to retail and wholesale customers, which represent TEP's primary source of revenue, as power is delivered. TEP adopted the new guidance using the modified retrospective approach. There was no adjustment identified or recorded to the opening balance of retained earnings on adoption. The Company applied the new revenue guidance to contracts with customers that were not completed at the date of initial application, January 1, 2018. The new guidance requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. See Note 3 for additional disclosure related to TEP's operating revenues.

Compensation—Retirement Benefits

Effective January 1, 2018, TEP adopted accounting guidance that requires an employer to disaggregate the service cost component from the other components of net periodic benefit cost. TEP no longer capitalizes the non-service cost components of net periodic benefit cost as part of inventory or plant in service and presents non-service costs in Other, Net on the Condensed Consolidated Statements of Income. The adoption of this change in accounting principle did not have a material impact on TEP's financial position or results of operations.

Derivatives and Hedging

Effective January 1, 2018, TEP early adopted accounting guidance that simplifies the application of hedge accounting through changes to both the designation and measurement guidance and is intended to enable the Company to better portray the economics of its risk management activities in its financial statements. The adoption of this change in accounting principle did not have a material impact on TEP's financial statements and disclosures.

Reclassification of Certain Tax Effects

Effective January 1, 2018, TEP early adopted accounting guidance that permits reclassification of certain tax effects resulting from the TCJA from accumulated other comprehensive income to retained earnings. TEP applied the guidance as of the beginning of the period of adoption. On adoption, TEP recorded a one-time reclassification of $1 million from Accumulated Other Comprehensive Loss to Retained Earnings on the Condensed Consolidated Balance Sheets as a result of income tax effects due to the reduction in the U.S. federal statutory tax rate. See Note 11 for additional disclosure related to the TCJA.

NOTE 2. REGULATORY MATTERS

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

2017 RATE ORDER

Provisions of the 2017 Rate Order, which were effective February 27, 2017, include, but are not limited to:

- a non-fuel base rate increase of $81.5 million; and
- adoption of TEP's proposed depreciation and amortization rates, which included a reduction in the depreciable life for San Juan Unit 1.

The ACC deferred matters related to net metering and rate design for new DG customers to a second phase of TEP’s rate case (Phase 2).

Phase 2 Order

On September 20, 2018, the ACC issued an order establishing, among other things, an export rate that replaced net metering for excess solar generation (Phase 2 Order). Residential and small commercial customers who apply to interconnect their solar generation systems to TEP's distribution system after the date of the order will no longer qualify for net metering. Customers who applied before the date of the order were grandfathered under previous net metering rules for a period of 20 years from the date of interconnection of their solar generation system.

Provisions of the Phase 2 Order for new DG customers include:

- an option to select from existing Time-of-Use rate schedules;

- a monthly bill credit for customer solar generation exported to TEP's grid calculated using an export rate approved by the ACC; and
- an annual update to the export rate based on TEP's actual solar PPA and generation facilities costs, which are expected to decline. The export rate at the time of customers' applications to interconnect will be locked for 10 years. The initial export rate was set at 9.64 cents per kilowatt-hour (kWh).

FEDERAL TAX LEGISLATION

Arizona Corporation Commission

In December 2017, the ACC opened a docket requesting that all regulated utilities submit proposals to address passing the benefits of the TCJA through to customers. In April 2018, the ACC approved TEP’s proposal (ACC Refund Order) to return the savings from the Company’s federal income tax reduction under the TCJA to its customers through a combination of a customer bill credit and a regulatory liability that reflects the deferral of a portion of the savings to be returned to customers in TEP's next rate case, which is expected to be filed in 2019. The ACC Refund Order was effective May 1, 2018.

As a result of the ACC Refund Order, the Company will use a bill credit in 2018 to refund to customers: (i) $27.5 million related to the reduction in the federal corporate income tax rate; and (ii) $9 million related to an estimate of Excess Deferred Income Taxes (EDIT) amortization. The customer bill credit will be trued-up annually to reflect actuals for kWh sales and EDIT amortization. TEP recognized a reduction in Operating Revenues on the Condensed Consolidated Statements of Income of $12 million and $29 million in the three and nine months ended September 30, 2018, respectively. TEP's regulatory liability balance related to the ACC Refund Order was $1 million as of September 30, 2018. See Note 11 for additional information regarding the TCJA.

Federal Energy Regulatory Commission

In March 2018, the FERC issued an order directing TEP to either: (i) submit proposed revisions to its stated transmission rates or stated transmission revenue requirements to reflect the change in the federal corporate income tax rate as a result of the TCJA; or (ii) show cause why it should not be required to do so (FERC Refund Order). In May 2018, TEP responded to the order and proposed an overall transmission rate reduction of approximately 5.3%, reflecting the lower federal tax rate, to be effective March 21, 2018. As a result, TEP recognized a reduction in Operating Revenues on the Condensed Consolidated Statements of Income of $1 million in the nine months ended September 30, 2018. The transmission rate reduction did not have a material impact on TEP's financial position or results of operations in the three months ended September 30, 2018. TEP cannot predict the outcome of the order.

Also in March 2018, the FERC issued a Notice of Inquiry (NOI) regarding the effect of the TCJA. The NOI seeks comments on a number of issues including how to reflect the amortization of the EDIT regulatory liability balances in rates. TEP cannot predict the impact of the NOI.

See Note 11 for additional information regarding the TCJA.

COST RECOVERY MECHANISMS

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

Purchased Power and Fuel Adjustment Clause

TEP's Purchased Power and Fuel Adjustment Clause (PPFAC) rate is adjusted annually each April 1st and goes into effect for the subsequent 12-month period unless modified by the ACC. The PPFAC rate includes: (i) a forward component which is calculated by taking the difference between forecasted fuel and purchased power costs and the amount of those costs established in rates designed to allow a regulated utility recovery of its costs of providing services and an opportunity to earn a reasonable return on its investment (Retail Rates); and (ii) a true-up component that reconciles the difference between actual costs and those recovered in the preceding 12-month period. The PPFAC bank balance was over-collected by $20 million as of September 30, 2018, and by $9 million as of December 31, 2017.

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

Period	Cents per kWh
May 2018 through March 2019	0.20
March 2017 through April 2018 [1]	(0.20)
May 2016 through February 2017	0.15

(1) In February 2017, the ACC approved a PPFAC credit to begin returning the over-collected PPFAC bank balance to customers until the effective date of the 2018 PPFAC rate.

Renewable Energy Standard

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

In January 2018, the ACC approved TEP's 2018 RES implementation plan with a budget amount of $54 million, which is recovered through the RES surcharge. The recovery funds the following: (i) the above market cost of renewable power purchases; (ii) previously awarded performance-based incentives for customer-installed DG; and (iii) various other program costs.

Energy Efficiency Standards

TEP is required to implement cost-effective Demand Side Management (DSM) programs to comply with the ACC's Energy Efficiency Standards (EE Standards). The EE Standards provide regulated utilities a DSM surcharge to recover from retail customers the costs to implement DSM programs, as well as an annual performance incentive. Energy savings realized through the programs count toward meeting the EE Standards and the associated lost revenues are partially recovered through the Lost Fixed Cost Recovery (LFCR) mechanism.

TEP earns the DSM performance incentive by meeting objectives stated in its energy efficiency implementation plan. The Company records its annual DSM performance incentive for the prior calendar year in the first quarter of each year. TEP recorded $2 million in 2018 and 2017 related to performance in Operating Revenues on the Condensed Consolidated Statements of Income.

In August 2017, TEP submitted its application for the 2018 energy efficiency implementation plan with a budget of $23 million and requested a waiver of the 2018 EE Standard. TEP expects to receive a decision on its 2018 energy efficiency implementation plan by the end of 2018. In May 2018, TEP notified the ACC that it would file an application for a 2019 energy efficiency implementation plan within 60 days of the approval of the 2018 energy efficiency implementation plan.

Lost Fixed Cost Recovery Mechanism

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

TEP recorded regulatory assets and recognized LFCR revenues of $5 million and $18 million in the three and nine months ended September 30, 2018, respectively, and $6 million and $17 million in the three and nine months ended September 30, 2017, respectively. LFCR revenues are included in Operating Revenues on the Condensed Consolidated Statements of Income.

REGULATORY ASSETS AND LIABILITIES

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

($ in millions)	Remaining Recovery Period (years)	September 30, 2018	December 31, 2017
Regulatory Assets			
Pension and Other Postretirement Benefits	Various	$ 121	$ 126
Early Generation Retirement Costs [1]	Various	74	84
Income Taxes Recoverable through Future Rates	Various	43	40
Derivatives	3	42	18
Final Mine Reclamation and Retiree Healthcare Costs [2]	19	33	31
Lost Fixed Cost Recovery	2	32	29
Property Tax Deferrals	1	25	24
Springerville Unit 1 Leasehold Improvements [3]	5	12	14
Other Regulatory Assets	Various	22	22
Total Regulatory Assets		404	388
Less Current Portion	1	110	94
Total Non-Current Regulatory Assets		$ 294	$ 294
Regulatory Liabilities			
Income Taxes Payable through Future Rates [4]	Various	$346	$353
Net Cost of Removal [5]	Various	169	180
Renewable Energy Standard	Various	52	44
Purchased Power and Fuel Adjustment Clause	1	20	9
Deferred Investment Tax Credits	Various	8	14
Other Regulatory Liabilities	Various	9	5
Total Regulatory Liabilities		604	605
Less Current Portion	1	110	89
Total Non-Current Regulatory Liabilities		$494	$516

(1) Includes the net book value and other related costs of Navajo Generating Station (Navajo) and H. Wilson Sundt Generating Station (Sundt) Units 1 and 2 reclassified from Utility Plant, Net on the Condensed Consolidated Balance Sheets due to the planned early retirement of the facilities. Navajo and Sundt Units 1 and 2 are being fully recovered in base rates using various useful lives through 2030.

(2) Represents costs associated with TEP's jointly-owned facilities at San Juan, Four Corners Generating Station (Four Corners), and Navajo. TEP recognizes these costs at future value and is permitted to recover these costs on a pay-as-you-go basis through the PPFAC mechanism. The majority of final mine reclamation costs are expected to occur through 2037.

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

(4) Includes balances related to EDIT as a result of the revaluation of deferred income taxes in 2017 due to the TCJA. TEP is amortizing the EDIT balances in accordance with applicable federal income tax laws, which require the amortization of a majority of the balance over the remaining life of the related asset. In April 2018, the ACC Refund Order was approved requiring TEP to return EDIT amortization of the ACC-jurisdictional assets with customers. See Note 11 for additional information regarding the TCJA.

(5) Represents an estimate of the future cost of retirement net of salvage value. These are amounts collected through revenue for transmission, distribution, and generation plant and general and intangible plant which are not yet

expended.

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

FERC COMPLIANCE

In 2016, the FERC issued orders relating to certain late-filed transmission service agreements (TSAs), which resulted in TEP paying time-value refunds to the counterparties of these TSAs. In January 2017, TEP and one of the TSA counterparties entered into a settlement agreement resulting in the counterparty paying TEP $8 million. The settlement amount was recorded in Other, Net on the Condensed Consolidated Statements of Income. As a result of the settlement, TEP dismissed a previously filed appeal. In May 2017, the FERC informed TEP that the related investigation was closed. As management no longer believed a loss was probable, TEP reversed the $5 million remaining balance related to potential time-value refunds in Current Liabilities—Other on the Condensed Consolidated Balance Sheets offsetting Operating Revenues on the Condensed Consolidated Statements of Income.

NOTE 3. REVENUE

TEP earns the majority of its revenues from the sale of power to retail and wholesale customers based on regulator-approved tariff rates. Most of the Company's contracts have a single performance obligation, the delivery of power. TEP satisfies the performance obligation over time as power is delivered and control is transferred to the customer. The Company bills for power sales based on the reading of electric meters on a systematic basis throughout the month. In general, TEP's contracts have payment terms of 10 to 20 days from the date the bill is rendered. TEP considers any payment not received by the due date delinquent and charges the customer a late payment fee. No component of the transaction price is allocated to unsatisfied performance obligations.

TEP has certain contracts with variable transaction pricing that require it to estimate the resulting variable consideration. TEP's variable consideration includes revenues that are subject to refund and performance incentive revenues. TEP estimates variable consideration at the most likely amount to which the Company expects to be entitled and recognizes a refund liability until TEP is certain that the Company will be entitled to the consideration. The Company includes estimated amounts of variable consideration in the transaction price to the extent it is probable that changes in its estimate will not result in significant reversals of revenue in subsequent periods.

DISAGGREGATION OF REVENUES

The following table presents the disaggregation of TEP’s Operating Revenues on the Condensed Consolidated Statements of Income by type of service:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Retail	$ 345	$ 334	$ 810	$ 801
Wholesale	79	44	152	116
Other Services	24	27	74	71
Revenues from Contracts with Customers	448	405	1,036	988
Alternative Revenues	5	6	20	19
Other	7	6	33	31
Total Operating Revenues	$ 460	$ 417	$ 1,089	$ 1,038

Retail Revenues

TEP’s tariff-based sales to residential, commercial, and industrial customers are regulated by the ACC and recognized when power is delivered at the amount of consideration that the Company expects to receive in exchange. Retail Revenues include an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period. At the end of the month, amounts of power delivered since the last meter reading are estimated and the corresponding unbilled revenue is calculated using anticipated Retail Rates. Unbilled revenues are dependent upon a number of factors that require management's judgment including estimates of retail sales, customer usage patterns, and pricing. Once the usage is estimated, TEP applies the anticipated rate and records revenue. Unbilled revenues increase during the spring and summer months and decrease during the fall and winter months due to the seasonal fluctuations of TEP's actual load. The timing of revenue recognition, billings, and cash collections results in billed and unbilled accounts receivable balances on the balance sheet. See Note 4 for components of Accounts Receivable, Net on the Condensed Consolidated Balance Sheets.

In January 2018, TEP began to recognize a provision for revenues subject to refund, which reduces operating revenues, and a current regulatory liability for savings expected to be returned to customers from the Company's federal income tax reduction under the TCJA. In April 2018, the ACC approved the ACC Refund Order effective May 1, 2018. As a result of the ACC Refund Order, the Company is using a bill credit in 2018 to return savings to customers. See Note 2 for more information regarding the ACC Refund Order.

Wholesale Revenues

TEP's operations include the wholesale marketing of electricity and transmission to other utilities and power marketers, which may include capacity, power, transmission, and ancillary services. When TEP promises to provide distinct services within a contract, the Company identifies one or more performance obligations. The Company recognizes revenue for wholesale and transmission sales at FERC-approved rates based on demand (for capacity) or the reading of meters (for power). For contracts with multiple performance obligations, all deliverables are eligible for recognition in the month of production; therefore, it is not necessary to allocate the transaction price among the identified performance obligations.

In March 2018, the FERC issued the FERC Refund Order. In May 2018, TEP responded to the order and proposed an overall transmission rate reduction to be effective March 21, 2018. The related revenue subject to refund recorded did not have a material impact on TEP's financial position or results of operations. TEP cannot predict the outcome of the order. See Note 2 for more information regarding the FERC Refund Order.

Other Services Revenues

Other Services Revenues primarily include management fees for Springerville Unit 3, miscellaneous service-related revenues, and reimbursement of various operating expenses for the use of the Springerville Common Facilities by Springerville Units 3 and 4 and the Springerville Coal Handling Facilities by Springerville Unit 3. As the operating agent for the third-party owner of Springerville Unit 3, TEP may earn an annual incentive or be required to refund its monthly management fee based on unit availability.

Alternative Revenues

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria established by a regulator are met. TEP has identified its LFCR mechanism and DSM performance incentive as alternative revenues. See Note 2 for additional information regarding these cost recovery mechanisms.

Other Revenues

Other Revenues include gains and losses on derivative contracts, late and returned payment finance charges, and lease income. See Note 10 for information regarding derivative instruments.

NOTE 4. ACCOUNTS RECEIVABLE

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

(in millions)	September 30, 2018	December 31, 2017
Customer [1]	$ 120	$ 81
Customer, Unbilled	61	39
Due from Affiliates (Note 5)	6	7
Other	15	16
Allowance for Doubtful Accounts	(6)	(5)
Accounts Receivable, Net	$ 196	$ 138

(1) Includes $4 million as of September 30, 2018, and $9 million as of December 31, 2017, of receivables related to revenue from derivative instruments.

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NOTE 5. RELATED PARTY TRANSACTIONS

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

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

(in millions)	September 30, 2018	December 31, 2017
Receivables from Related Parties		
UNS Electric	$ 4	$ 5
UNS Gas	1	2
UNS Energy	1	—
Total Due from Related Parties	$ 6	$ 7
Payables to Related Parties		
SES	$ 2	$ 3
UNS Energy	1	1
UNS Electric	—	—
Total Due to Related Parties	$ 3	$ 4

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

(in millions)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Goods and Services Provided by TEP to Affiliates				
Transmission Revenues, UNS Electric (1)	$ 2	$ 2	$ 5	$ 5
Wholesale Revenues, UNS Electric (1)	1	—	1	—
Control Area Services, UNS Electric (2)	1	1	2	2
Common Costs, UNS Energy Affiliates (3)	4	4	13	12
Goods and Services Provided by Affiliates to TEP				
Supplemental Workforce, SES (4)	4	4	11	11
Corporate Services, UNS Energy (5)	2	1	5	4
Corporate Services, UNS Energy Affiliates (6)	2	1	5	3

(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 are allocated to its subsidiaries using the Massachusetts Formula, an industry accepted method of allocating common costs to affiliated entities. TEP's allocation is approximately 82% of UNS Energy's allocated costs. Corporate Services, UNS Energy includes legal, audit, and Fortis management fees. TEP's share of Fortis' management fees were $1 million and $4 million for the three and nine months ended September 30, 2018, respectively, and $1 million and $3 million, for the three and nine months ended September 30, 2017, respectively.

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(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.

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

There have been no significant changes to TEP's debt, credit facility, or capital lease obligations from those reported in its 2017 Annual Report on Form 10-K/A, except as noted below.

CREDIT FACILITY

TEP's unsecured credit agreement includes the following:

($ in millions)	Capacity	LOC Sub-Limit	Borrowed	Available	Weighted Average Interest Rate	Pricing [1]
September 30, 2018						
Credit Facility	$250	$ 50	$ 15	$ 235	3.24 %	LIBOR + 1.00% or ABR + 0.00%

(1) Interest rates and fees under the credit facility are based on a pricing grid tied to TEP's credit rating.

As of November 1, 2018, TEP had $205 million available under its revolving credit commitments and a Letter of Credit (LOC) facility.

CAPITAL LEASE OBLIGATIONS

In 2017, TEP entered into a 20-year tolling PPA with Salt River Project Agricultural Improvement and Power District (SRP) to purchase and receive all 550 megawatt (MW) of capacity, power, and ancillary services from Gila River Generating Station (Gila River) Unit 2, which includes a three-year option to purchase the unit (Tolling PPA). TEP’s obligations under the agreement were contingent upon SRP's acquisition of Gila River Units 1 and 2 from third-parties (Gila Acquisition). SRP completed the Gila Acquisition in May 2018. As a result, TEP had $164 million recorded in both Long Term Liabilities—Capital Lease Obligations and Utility Plant Under Capital Leases on the Condensed Consolidated Balance Sheets as of September 30, 2018. The amount reflects the fair value of the unit, which was determined by SRP's purchase price. TEP anticipates exercising its option to purchase Gila River Unit 2 in December 2019 for approximately $164 million. Over the expected 20-month lease term, TEP will pay a monthly demand charge consisting of: (i) a fixed capacity charge of approximately $1 million, and (ii) an operating fee to compensate SRP for the non-fuel costs of operating Gila River Unit 2. TEP recovers the monthly capacity charge and operating fee through the PPFAC.

TEP’s minimum lease payments consist of the fixed capacity charge and purchase option price. As of September 30, 2018, capital lease obligations related to the Tolling PPA mature on the following dates:

(in millions)	Capital Lease Obligations
2018	$ 3
2019	176
2020	2
2021	—
2022	—
Total 2018-2022	181
Thereafter	—
Less: Imputed Interest	(17)
Total	$ 164

TEP recorded $3 million and $5 million of capital lease interest in Purchased Power on the Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2018, respectively, and $2 million of amortization in Regulatory and Other Assets—Regulatory Assets on the Condensed Consolidated Balance Sheets related to the Tolling PPA capital lease as of September 30, 2018.

NOTE 7. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

In addition to those reported in its 2017 Annual Report on Form 10-K/A, TEP entered into the following long-term commitments through September 30, 2018:

(in millions)	2018	2019	2020	2021	2022	Thereafter	Total
Fuel, Including Transportation	$ 4	$ 5	$ 5	$ 5	$ 5	$ 1	$ 25

Fuel, Including Transportation

TEP has firm transportation agreements with capacity sufficient to meet its load requirements. These agreements expire in various years between 2019 and 2040. In January 2018, TEP entered into a transportation agreement with El Paso Natural Gas Company, LLC, extending the expiration date of the existing agreement from April 2018 to April 2023.

In October 2018, Westmoreland Coal Company (WCC), the owner of San Juan Coal Company's (SJCC), filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. Public Service Company of New Mexico (PNM), the operator of San Juan, has an existing Coal Supply Agreement (CSA) with WCC to supply coal from SJCC's San Juan Mine to San Juan. TEP is not a party to the CSA, but has minimum purchase obligations under a joint participation agreement. WCC is expected to provide adequate liquidity to support continued operations at the San Juan Mine throughout the restructuring process. TEP believes it has adequate resource capacity to meet its near-term load obligations in the event WCC's operations at the San Juan Mine are curtailed. TEP cannot currently predict the outcome of this matter or the long-term impacts on operations at San Juan.

CONTINGENCIES

Legal Matters

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

Claims Related to San Juan Generating Station

WildEarth Guardians

In 2013, WildEarth Guardians (WEG) filed a Petition for Review in the U.S. District Court for the District of Colorado against the Office of Surface Mining (OSM) challenging several unrelated mining plan modification approvals, including two issued in 2008 related to SJCC's San Juan Mine. The petition alleges various National Environmental Policy Act (NEPA) violations against the OSM, including: (i) failure to provide requisite public notice and participation, and (ii) failure to analyze certain environmental impacts. WEG's petition seeks various forms of relief, including voiding and remanding the various mining modification approvals, enjoining the federal defendants from re-issuing the approvals until they can demonstrate compliance with the NEPA, and enjoining operations at the affected mines. SJCC intervened in this matter and was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now pending. In July 2016, the federal defendants filed a motion asking that the matter be voluntarily remanded to the OSM so the OSM may prepare a new environmental impact statement (EIS) under the NEPA regarding the impacts of the San Juan Mine mining plan approval. In August 2016, the court issued an order granting the motion for remand to conduct further environmental analysis and complete an EIS by August 31, 2019. The order provides that: (i) the OSM's decision approving the mining plan will remain in effect during this process; or (ii) if the EIS is not completed by August 31, 2019, then the approved mine plan will immediately be vacated, absent further court order. In May 2018, the OSM released a draft EIS for public comment which was open through July 2018. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Mine Reclamation at Generation Facilities Not Operated by TEP

TEP pays ongoing mine reclamation costs related to coal mines that supply generation facilities in which TEP has an ownership interest but does not operate. TEP is also liable for a portion of final mine reclamation costs upon closure of the mines servicing Navajo, San Juan, and Four Corners. TEP’s share of reclamation costs at all three mines is expected to be $65 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The balance sheet reflected a total liability related to reclamation of $35 million as of September 30, 2018, and $34 million as of December 31, 2017.

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

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

Performance Guarantees

TEP has joint participation agreements with participants at Navajo, San Juan, Four Corners, and Luna Generating Station (Luna). The participants in each of the generation facilities, including TEP, have guaranteed certain performance obligations. Specifically, in the event of payment default, each non-defaulting participant has agreed to bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. With the exception of Four Corners, there is no maximum potential amount of future payments TEP could be required to make under the guarantees. The maximum potential amount of future payments is $250 million at Four Corners. As of September 30, 2018, 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 environmental laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species, and other environmental matters that have the potential to impact TEP's current and future operations. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and financial results. TEP expects to recover the cost of environmental compliance from its ratepayers. TEP believes it is in compliance with applicable environmental laws and regulations.

NOTE 8. EMPLOYEE BENEFIT PLANS

Net periodic benefit cost includes the following components:

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended September 30,			
(in millions)	2018	2017	2018	2017
Service Cost	$4	$ 3	$ 1	$ 1
Interest Cost	4	3	1	1
Expected Return on Plan Assets	(7)	(6)	(1)	(1)
Amortization of Net Loss	1	2	—	—
Net Periodic Benefit Cost	$2	$ 2	$ 1	$ 1
	Nine Months Ended September 30,			
(in millions)	2018	2017	2018	2017

Service Cost	$11	$ 9	$ 3	$ 3
Interest Cost	12	11	2	2
Expected Return on Plan Assets	(21)	(18)	(1)	(1)
Amortization of Net Loss	5	6	—	—
Net Periodic Benefit Cost	$7	$ 8	$ 4	$ 4

The non-service components of net periodic benefit cost are included in Other, Net on the Condensed Consolidated Statements of Income.

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NOTE 9. 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:

	Nine Months Ended September 30,	
(in millions)	2018	2017
Gila River Unit 2, Capital Lease	$ 164	$ —
Net Cost of Removal Decrease [1]	(7)	(88)
Accrued Capital Expenditures	48	18
Renewable Energy Credits	3	4

[1] Non-cash Net Cost of Removal represents an accrual for future cost of retirement net of salvage values that does not impact earnings. As approved in the 2017 Rate Order, TEP implemented new depreciation reserves and rates effective March 1, 2017. See Note 2 for additional information.

NOTE 10. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

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

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS

The following tables present, by level within the fair value hierarchy, TEP's assets and liabilities accounted for at fair value on a recurring basis 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)	September 30, 2018			
Assets				
Cash Equivalents[1]	$15	$—	$ —	$15
Restricted Cash[1]	10	—	—	10
Energy Derivative Contracts, Regulatory Recovery[2]	—	5	—	5
Energy Derivative Contracts, No Regulatory Recovery[2]	—	—	4	4
Total Assets	25	5	4	34
Liabilities				
Energy Derivative Contracts, Regulatory Recovery[2]	—	(44)	(4)	(48)
Total Liabilities	—	(44)	(4)	(48)
Total Assets (Liabilities), Net	$25	$(39)	$ —	$(14)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

	Gross Amount Recognized in the Balance Sheets	Gross Amount Not Offset in the Balance Sheets		Net Amount
		Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	
(in millions)	September 30, 2018			
Derivative Assets				
Energy Derivative Contracts	$9	$ 6	$ —	$ 3
Derivative Liabilities				
Energy Derivative Contracts	(48)	(6)	—	(42)
(in millions)	December 31, 2017			
Derivative Assets				
Energy Derivative Contracts	$12	$10	$—	$2
Derivative Liabilities				
Energy Derivative Contracts	(27)	(10)	—	(17)
Interest Rate Swap	(1)	—	—	(1)

DERIVATIVE INSTRUMENTS

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

The Company primarily applies the market approach for recurring fair value measurements. When TEP has observable inputs for substantially the full term of the asset or liability or uses quoted prices in an inactive market, it categorizes the instrument in

Level 2. TEP categorizes derivatives in Level 3 when an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers is used.

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

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

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

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

Cash Flow Hedges

To mitigate the exposure to volatility in variable interest rates on debt, TEP has an interest rate swap agreement that expires January 2020. The after-tax unrealized gains and losses on cash flow hedge activities are reported in the statement of comprehensive income. The estimated loss expected to be reclassified to earnings within the next twelve months is not material to TEP's financial position or results of operations.

The table below presents realized losses recorded to Interest Expense as well as total Interest Expense on the Condensed Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Realized Loss From Cash Flow Hedge	$ —	$ —	$ —	$ 1
Interest Expense	17	16	50	49

As of September 30, 2018, the total notional amount of the interest rate swap was $12 million.

Energy Derivative Contracts, Regulatory Recovery

TEP enters into energy contracts that are considered derivatives and qualify for regulatory recovery. The realized gains and losses on these energy contracts are recovered through the PPFAC mechanism and the unrealized gains and losses are deferred as a regulatory asset or a regulatory liability. The table below presents the unrealized gains and losses recorded to a regulatory asset or a regulatory liability on the balance sheet:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Unrealized Net Gain (Loss)	$ 8	$ (1)	$ (24)	$ (6)

Energy Derivative Contracts, No Regulatory Recovery

TEP enters into certain energy contracts that are considered derivatives but do not qualify for regulatory recovery. The Company records unrealized gains and losses for these contracts in the income statement unless a normal purchase or normal sale election is made. For contracts that meet the trading definition, as defined in the PPFAC plan of administration, TEP must share 10% of any realized gains with retail customers through the PPFAC mechanism. The table below presents amounts recorded in Operating Revenues on the Condensed Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Operating Revenues	$ —	$ 1	$ 5	$ 5

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivative Volumes

As of September 30, 2018, TEP had energy contracts that will settle on various expiration dates through 2029. The following table presents volumes associated with the energy contracts:

	September 30, 2018	December 31, 2017
Power Contracts GWh	2,499	2,589
Gas Contracts BBtu	146,612	137,952

Level 3 Fair Value Measurements

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

	Valuation Approach	Fair Value of Assets	Fair Value of Liabilities	Unobservable Inputs	Range of Unobservable Input	
(in millions)	September 30, 2018					
Forward Power Contracts	Market approach	$4	$ (4)	Market price per MWh	$ 17.05	$ 43.35
(in millions)	December 31, 2017					
Forward Power Contracts	Market approach	$3	$(1)	Market price per MWh	$17.65	$34.60

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2018	2017	2018	2017
Beginning of Period	$ 5	$ 4	$ 2	$ 1
Gains (Losses) Recorded				
Regulatory Assets or Liabilities, Derivative Instruments	1	1	1	3
Operating Revenues	—	—	4	4
Settlements	(6)	(1)	(7)	(4)
End of Period	$ —	$ 4	$ —	$ 4
Gains (Losses), Assets (Liabilities) Still Held	$ (2)	$ —	$ —	$ 4

CREDIT RISK

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

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

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

The value of all derivative instruments in net liability positions under contracts with credit risk-related contingent features, including contracts under the normal purchase normal sale exception, was $69 million as of September 30, 2018, compared with $27 million as of December 31, 2017. As of September 30, 2018, TEP had no LOCs as credit enhancements with its counterparties. If the credit risk contingent features were triggered on September 30, 2018, TEP would have been required to post an additional $69 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. Borrowings under revolving credit facilities approximate fair value due to the short-term nature of these financial instruments. These items have been excluded from the table below.

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

(in millions)	Fair Value Hierarchy	Face Value September 30, 2018	Face Value December 31, 2017	Fair Value September 30, 2018	Fair Value December 31, 2017
Liabilities					
Long-Term Debt, including Current Maturities	Level 2	$1,466	$ 1,466	$1,484	$ 1,547

NOTE 11. INCOME TAXES

Income tax expense differs from the amount of income tax determined by applying the statutory federal income tax rate of 21% in 2018 and 35% in 2017 to pre-tax income due to the following:

(in millions)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Federal Income Tax Expense at Statutory Rate	$ 25	$ 44	$45	$87
State Income Tax Expense, Net of Federal Deduction	4	4	8	8
Federal/State Tax Credits	(4)	(4)	(7)	(8)
Excess Deferred Income Taxes	(4)	—	(8)	—
Other	(2)	(2)	(2)	(3)
Total Federal and State Income Tax Expense	$ 19	$ 42	$36	$84

On December 22, 2017, the President of the United States of America signed into law the TCJA, which enacted significant changes to the Internal Revenue Code including a reduction in the federal corporate income tax rate from up to 35% to 21% effective for tax years beginning after 2017. In addition, the TCJA provided modifications to bonus depreciation rules and limitations on the deductibility of interest expense, both of which include carve-outs for regulated utilities.

As a result of the TCJA, the Company was required to revalue its deferred tax assets and liabilities at the new federal tax rate as of the date of enactment. This resulted in a net decrease to deferred income tax liabilities and the establishment of a regulatory liability related to EDIT. TEP is amortizing the EDIT balance in accordance with applicable federal income tax laws, which require the amortization of a majority of the balance over the remaining life of the related plant. In April 2018, the ACC Refund Order was approved requiring TEP to share EDIT amortization of the ACC-jurisdictional assets with customers. The EDIT balance related to the effects of the TCJA included in

Regulatory Liabilities on the Condensed Consolidated Balance Sheets was $336 million as of September 30, 2018. See Note 2 for additional information regarding the ACC Refund Order and the FERC NOI.

Under the TCJA, Alternative Minimum Tax (AMT) credit carryforwards will be refunded if not used to offset federal income tax liabilities. As of September 30, 2018, TEP had a receivable balance of $13 million related to AMT credit carryforwards in Current Assets—Other on the Condensed Consolidated Balance Sheets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

In August 2018, the Internal Revenue Service proposed regulations on the bonus depreciation carve-out for regulated utilities. Based on the proposed regulation, the Company adjusted its estimated provision and the results did not have a material impact on TEP's financial position or results of operations. TEP's accounting for the income tax effects of the bonus depreciation provisions included in the TCJA has been completed as of September 30, 2018.

NOTE 12. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

LEASES

In February 2016, the FASB issued an ASU that will require the recognition of leased assets and liabilities by lessees for those leases classified as operating leases with a lease term greater than 12 months and disclosure of additional quantitative and qualitative information about leasing arrangements. The standard is effective for periods beginning January 1, 2019, and is to be applied using a modified retrospective approach or an optional transition method with practical expedient options. The modified retrospective approach requires the restatement of prior periods and presentation of lease disclosures under the new guidance for all periods presented. The optional transition method allows entities to continue to apply the current lease guidance in the comparative periods presented in the year of adoption and apply the transition provisions of the new guidance on the effective date of the new guidance. Early adoption is permitted. In January 2018, the FASB issued an additional optional practical expedient that permits entities to not evaluate existing land easements that were not previously accounted for as leases.

TEP plans to adopt this guidance effective January 1, 2019 and will apply the transition provisions of the new standard at the adoption date. The Company expects to elect a package of practical expedients that allows it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases, and the initial direct costs for any existing leases. In addition, TEP will elect the practical expedient related to land easements, and the new lease guidance will be applied on a prospective basis to all new or modified land easements.

TEP’s leasing activities accounted for as operating leases primarily relate to leases for land and rail cars. The adoption of the new guidance will affect the Company’s Condensed Consolidated Balance Sheets as the Company will be required to record lease assets and lease liabilities related to these operating lease arrangements. TEP is currently identifying and implementing changes to processes and controls and preparing the expanded lease disclosures. The Company does not expect the new ASU to materially affect its balance sheet, results of operations or cash flows. Management continues to monitor standard-setting activities that may affect the transition requirements of the new lease standard.

INTERNAL-USE SOFTWARE

In August 2018, the FASB issued an ASU that will clarify accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. Under the new guidance, customers will apply the same criteria for capitalizing implementation costs as they would for an arrangement that has a software license. The ASU also provides specific requirements for the classification and presentation of the capitalized implementation costs and the related amortization of those costs. The standard is effective for periods beginning January 1, 2020, and should be applied either retrospectively or prospectively after the date of adoption. Early adoption is permitted. TEP plans to early adopt the new standard prospectively effective January 1, 2019 and does not expect the ASU to have a material impact on its 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 financial condition, and the outlook for TEP. It includes the following:

- outlook and strategies;
- operating results in the third quarter and first nine months of 2018 compared with the same periods in 2017;
- factors affecting our results of operations and outlook;
- liquidity and capital resources including contractual obligations, capital expenditures, and environmental matters;
- critical accounting policies and estimates; and
- recent accounting pronouncements.

Management’s Discussion and Analysis includes financial information prepared in accordance with GAAP financial measures.

Management’s Discussion and Analysis should be read in conjunction with the 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 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 2017 Annual Report on Form 10-K/A, 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: (i) global, national, regional, and local economic conditions; (ii) volatility in the financial markets; (iii) environmental laws and regulations; and (iv) other regulatory factors.

Our plans and strategies include the following:

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

2018 Operational and Financial Highlights

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

- In April 2018, the ACC Refund Order was approved effective May 1, 2018. The Order provides that we refund customers a total of $36.5 million through a bill credit in 2018. TEP will continue to return savings to customers through a combination of a bill credit and a regulatory liability in 2019 and through the completion of our next rate case.
- In May 2018, we responded to the FERC Refund Order with a proposed overall transmission rate reduction, reflecting the lower federal tax rate, to be effective March 21, 2018. TEP cannot predict the outcome of the order.
- In May 2018, SRP completed the Gila Acquisition. As a result, TEP had $164 million recorded in both Long Term Liabilities—Capital Lease Obligations and Utility Plant Under Capital Leases on the Condensed Consolidated Balance Sheets as of September 30, 2018, related to the 20-year Tolling PPA. The amount represents the fair value of the unit,

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which was determined by SRP's purchase price. The additional 550 MW of capacity, power, and ancillary services will allow us to continue to move toward our long-term goal of resource diversification.

- On September 20, 2018, the ACC issued the Phase 2 Order. The order established, among other things, an initial export rate that replaced net metering for excess solar generation for customers who applied for interconnection to TEP's distribution system after the date of the order. The new rate went into effect October 1, 2018.

RESULTS OF OPERATIONS

Because weather and other factors cause seasonal fluctuations in sales of power, our quarterly results of operation are not indicative of annual results. TEP's summer peaking load occurs during the third quarter of the year when cooling demand is higher, which results in higher revenue during this period. By contrast, lower sales of power occur during the first quarter of the year, due to mild winter weather in our retail service territory.

The following discussion provides the significant items that affected TEP's results of operations in the third quarter and first nine months of 2018 compared with the same periods in 2017. The significant items affecting net income are presented on an after-tax basis.

The third quarter of 2018 compared with the third quarter of 2017

TEP reported net income of $95 million in the third quarter of 2018 compared with net income of $82 million in the third quarter of 2017. The increase of $13 million, or 16%, was primarily due to:

- $20 million in lower income tax expense due to the reduction of the federal effective income tax rate primarily related to the enactment of the TCJA. See Note 11 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the TCJA; and
- $7 million in higher retail revenue primarily due to an increase in usage related to favorable weather.

The increase was partially offset by:

- $10 million in lower retail revenue associated with the ACC Refund Order to return savings related to the TCJA to customers. The order was effective May 1, 2018. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the ACC Refund Order; and
- $5 million in higher operations and maintenance expense resulting primarily from an increase in maintenance expense related to planned generation outages in 2018 partially offset by a decrease in employee benefits expense.

The first nine months of 2018 compared with the first nine months of 2017

TEP reported net income of $176 million in the first nine months of 2018 compared with net income of $164 million in the first nine months of 2017. The increase of $12 million, or 7%, was primarily due to:

- $36 million in lower income tax expense due to the reduction of the federal effective income tax rate primarily related to the enactment of the TCJA. See Note 11 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the TCJA; and
- $16 million in higher retail revenue primarily due to an increase in rates as approved in the 2017 Rate Order that took effect February 27, 2017, and favorable weather.

The increase was partially offset by:

- $24 million in lower retail revenue associated with the ACC Refund Order to return savings related to the TCJA to customers. The order was effective May 1, 2018. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the ACC Refund Order;
- $11 million in higher operations and maintenance expense resulting primarily from an increase in maintenance expense related to planned generation outages in 2018 partially offset by a decrease in employee benefits expense; and
- $5 million in lower income from a settlement agreement and the reversal of accrued refunds associated with late-filed TSAs in 2017. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the settlement agreement.

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Retail Revenues and Key Statistics
The following table provides key statistics impacting operating revenues:

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
($ and kWh in millions)	2018	2017	Percent	2018	2017	Percent
Operating Revenues	$460	$417	10.3 %	$1,089	$1,038	4.9 %
Electric Sales (kWh)						
Residential	1,408	1,361	3.5 %	3,074	3,066	0.3 %
Commercial	682	653	4.4 %	1,683	1,671	0.7 %
Industrial	562	559	0.5 %	1,500	1,487	0.9 %
Mining	261	251	4.0 %	762	745	2.3 %
Public Authorities	4	3	33.3 %	12	13	(7.7)%
Total Retail Sales	2,917	2,827	3.2 %	7,031	6,982	0.7 %
Wholesale, Long-Term	151	204	(26.0)%	295	404	(27.0)%
Wholesale, Short-Term	1,684	772	118.1 %	3,914	2,615	49.7 %
Total Electric Sales	4,752	3,803	25.0 %	11,240	10,001	12.4 %
Average Revenue Per kWh (Cents/kWh)						
Retail	11.81	11.84	(0.3)%	11.52	11.48	0.3 %
Wholesale	4.18	3.63	15.2 %	3.50	3.27	7.0 %
Total Retail Customers				424,634	422,041	0.6 %

Operating Revenues increased by $43 million in the third quarter of 2018 when compared with the same period in 2017 primarily due to: (i) an increase in short-term wholesale sales due to an increase in available system capacity related to Gila River Unit 2; (ii) an increase in the PPFAC rate; and (iii) higher retail revenues related to an increase in usage due to favorable weather. The increase was partially offset by: (i) the return of savings related to the TCJA to customers; and (ii) a decrease in billings to third-party participants in Springerville Units 3 and 4. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the 2017 Rate Order, Cost Recovery Mechanisms, and the ACC Refund Order.

Operating Revenues increased by $51 million in the first nine months of 2018 when compared with the same period in 2017 primarily due to: (i) an increase in short-term wholesale sales resulting from an increase in available system capacity related to Gila River Unit 2; (ii) an increase in the PPFAC rate; (iii) higher retail revenues related to an increase in rates as approved in the 2017 Rate Order that took effect February 27, 2017, and favorable weather; and (iv) an increase in billings to third-party participants in Springerville Units 3 and 4. The increase was partially offset by: (i) the return of savings related to the TCJA to customers; and (ii) a 2017 reversal of an accrual related to the FERC ordered refunds for late-filed TSAs.

Short-term wholesale revenues are primarily related to ACC jurisdictional assets and are returned to retail customers by offsetting revenues against fuel and purchased power costs eligible for recovery through the PPFAC. Revenues related to Springerville Units 3 and 4 are primarily reimbursements by Tri-State Generation and Transmission Association, Inc., the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, with the corresponding expense recorded in Operating Expenses on the Condensed Consolidated Statements of Income.

Operating Expenses

Fuel and Purchased Power Expense

Fuel and Purchased Power Expense, which includes PPFAC recovery treatment, increased by $51 million, or 39%, and $64 million, or 20%, in the third quarter and first nine months of 2018, respectively, when compared with the same periods in 2017. The increases were primarily due to: (i) an increase in generation volumes; (ii) an increase in recovery of PPFAC costs as a result of changes in the PPFAC rate; and (iii) an increase in average cost of Purchased Power, Non-Renewables. The increases

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were partially offset by: (i) a decrease in Purchased Power, Non-Renewable volumes; and (ii) a decrease in the average cost of Natural Gas.

The following table presents TEP's sources of energy and average cost of power by type:

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
(kWh in millions)	2018	2017	Percent	2018	2017	Percent
Sources of Energy						
Coal-Fired Generation	1,927	2,212	(12.9)%	5,191	5,764	(9.9)%
Gas-Fired Generation	2,493	1,073	132.3 %	4,790	2,348	104.0 %
Utility-Owned Renewable Generation	22	21	4.8 %	66	65	1.5 %
Total Generation	4,442	3,306	34.4 %	10,047	8,177	22.9 %
Purchased Power, Non-Renewable	408	587	(30.5)%	1,240	1,912	(35.1)%
Purchased Power, Renewable	151	158	(4.4)%	516	525	(1.7)%
Total Generation and Purchased Power	5,001	4,051	23.5 %	11,803	10,614	11.2 %
(cents per kWh)						
Average Fuel Cost of Generated Power						
Coal	2.39	2.54	(5.9)%	2.43	2.40	1.3 %
Natural Gas	2.74	3.16	(13.3)%	2.42	3.23	(25.1)%
Average Cost of Purchased Power						
Purchased Power, Non-Renewable	7.58	4.88	55.3 %	4.52	3.93	15.0 %
Purchased Power, Renewable	9.65	10.39	(7.1)%	9.47	10.52	(10.0)%

Operations and Maintenance Expense

Operations and Maintenance Expense decreased by $1 million, or 1%, in the third quarter of 2018 when compared with the same period in 2017. The decrease was primarily due to: (i) a decrease in maintenance expense at Springerville Unit 4; (ii) a decrease in customer funded renewable energy and DSM programs; and (iii) a decrease in employee benefits expense. The decrease was partially offset by an increase in maintenance expense related to planned generation outages.

Operations and Maintenance Expense increased by $9 million, or 4%, in the first nine months of 2018 when compared with the same period in 2017. The increase was primarily due to: (i) an increase in maintenance expense related to planned generation outages; (ii) an increase in maintenance expense at Springerville Units 3 and 4; and (iii) a sales tax refund that occurred in 2017. The increase was partially offset by: (i) a decrease in customer funded renewable energy and DSM programs; and (ii) a decrease in the employee benefits expense.

Expenses related to Springerville Units 3 and 4 are reimbursed by Tri-State Generation and Transmission Association, Inc., the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, with corresponding amounts recorded in Operating Revenues on the Condensed Consolidated Statements of Income. Expenses related to customer funded renewable energy and DSM programs are collected from customers with corresponding amounts recorded in Operating Revenues on the Condensed Consolidated Statements of Income.

Other Income (Expense)

There were no significant changes to Other Income (Expense) in the third quarter of 2018 when compared with the same period in 2017. Other Income (Expense) decreased by $5 million, or 14%, in the first nine months of 2018 when compared with the same period in 2017. The decrease was primarily due to a settlement agreement related to late-filed TSAs in January 2017. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the settlement agreement.

Income Tax Expense

Income Tax Expense decreased by $23 million, or 55%, and $48 million, or 58%, in the third quarter and first nine months of 2018, respectively, when compared with the same periods in 2017. The decreases were primarily due to the reduction of the federal corporate income tax rate related to the enactment of the TCJA and a decrease in earnings before tax expense. See Note

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11 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the TCJA.

FACTORS AFFECTING RESULTS OF OPERATIONS

Regulatory Matters

TEP is subject to comprehensive regulation. The discussion below contains material developments to those matters disclosed in Part II, Item 7 of our 2017 Annual Report on Form 10-K/A and new regulatory matters occurring in 2018.

2017 Rate Order

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

- a non-fuel base rate increase of $81.5 million, a cost of equity component of 9.75%, and a cost of debt component of 4.32%; and
- adoption of TEP's proposed depreciation and amortization rates, which include a reduction in the depreciable life for San Juan Unit 1.

The ACC deferred matters related to net metering and rate design for new DG customers to Phase 2.

Distributed Generation

In 2016, the ACC approved an order related to the Value and Cost of DG docket that began to reform net metering in Arizona. The order adopted a number of net metering changes and polices including a requirement that TEP establish a DG export rate and create separate rate classes for new DG customers. The ACC deferred matters related to the DG export rate and rate design for new DG customers to Phase 2.

On September 20, 2018, the ACC issued an order related to the Phase 2 proceedings. The Phase 2 Order established, among other things, an export rate that replaced net metering for excess solar generation. Residential and small commercial customers who applied to interconnect their solar generating systems to TEP's distribution system after the date of the order no longer qualify for net metering. Customers who applied before the date of the order were grandfathered under previous net metering rules for a period of 20 years from the date of interconnection of their solar generation systems. Provisions of the Phase 2 Order for new DG customers include:

- an option to select from existing Time-of-Use rate schedules;
- a monthly bill credit for customer solar generation exported to TEP's grid calculated using an export rate approved by the ACC; and
- an annual update to the export rate based on TEP's actual solar PPA and generation facilities costs, which are expected to decline. The export rate at the time of customers' applications to interconnect will be locked for 10 years. The initial export rate was set at 9.64 cents per kWh.

DG customers grandfathered under the net metering rules will continue to have their solar generation netted against the kWhs they consume. The net sales are recorded in Operating Revenues on the Condensed Consolidated Statements of Income. New DG customers' solar generation will be reported gross of the kWhs they consume as approved in the Phase 2 Order. Sales of power by TEP to these customers will be calculated based on the respective retail rate and recorded in Operating Revenues on the Condensed Consolidated Statements of Income. Their solar generation exported into TEP's grid will be calculated based on the export rate as approved by the ACC and recorded in Purchased Power on the Condensed Consolidated Statements of Income. We expect to recover the cost for DG customer solar generation through the PPFAC up to an amount equal to market prices with any remaining cost being recovered through a RES surcharge.

TEP does not expect the change resulting from the replacement of net metering to have a material impact on the Company's results of operations in the near term. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information regarding Phase 2 Order.

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Federal Income Tax Legislation

Arizona Corporation Commission

In December 2017, the ACC opened a docket requesting that all regulated utilities submit proposals to address passing the benefits of the TCJA through to customers. In April 2018, the ACC Refund Order was approved effective May 1, 2018. The Order provides that we refund customers a total of $36.5 million through a bill credit in 2018. The customer bill credit will be trued-up annually to reflect actuals for kWh sales and EDIT amortization. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 and Liquidity and Capital Resources, Income Tax Position of this Form 10-Q for additional information regarding the ACC Refund Order.

Federal Energy Regulatory Commission

In March 2018, the FERC issued the FERC Refund Order. In May 2018, TEP responded to the order and proposed an overall transmission rate reduction of approximately 5.3%, reflecting the lower federal tax rate, to be effective March 21, 2018. We estimate that the proposed rate reduction will reduce operating revenues by approximately $2 million on an annual basis. TEP cannot predict the outcome of the order.

Also in March 2018, the FERC issued a NOI regarding the effect of the TCJA. The NOI seeks comments on a number of issues including how to return the amortization of the EDIT regulatory liability balances in rates. We are amortizing the EDIT balance in accordance with applicable federal income tax laws, which require the amortization of a majority of the balance over the remaining life of the related plant. TEP cannot currently predict the impact of the NOI.

See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information regarding the FERC Refund Order and NOI.

Generating Resources

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

As of September 30, 2018, approximately 40% of our generation capacity, including owned and leased resources, was from coal-fired generation.

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

Arizona Ballot Initiative

In August 2018, the Arizona Secretary of State certified a ballot initiative, proposed by a coalition of renewable energy advocates, to amend the state constitution. The initiative would require most Arizona utilities, including TEP, to generate at least 50% of their annual retail sales of electricity from renewable energy resources by 2030. The amendment, if passed by voters in the November 2018 general election, would increase our current Company target of meeting 30% of our customers’ energy needs with renewable resources by 2030.

Based on our preliminary analysis, passage of the ballot initiative could require TEP to invest an additional $2 billion of incremental capital related to new renewable and energy storage technologies compared to our current plans. We would seek to recover the additional capital expenditures, and other related costs, through rates leading to higher bills for our customers. TEP cannot predict the outcome of this initiative.

Arizona Energy Policy

In August 2018, the ACC opened a rulemaking docket to evaluate several energy policies. The docket will review possible modifications to existing renewable energy and energy efficiency requirements that could include establishing a goal to have clean energy resources make up at least 80% of most Arizona utilities' electricity generation portfolios by 2050. The adoption of any new policy would be subject to rulemaking proceedings at the ACC. We would seek the ACC's approval to recover any

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costs related to any new energy policies or requirements. TEP cannot predict the outcome of this matter or the impact on the Company's financial position or results of operations.

Navajo Generating Station

In 2017, the Navajo Nation approved a land lease extension which allows TEP and the co-owners of Navajo to continue operations through December 2019 and begin decommissioning activities thereafter. We are currently recovering Navajo capital and operating costs in base rates using a useful life through 2030. We plan to seek recovery of all unrecovered costs in our next ACC rate case, which is expected to be filed in 2019.

See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information regarding the planned early retirement of Navajo.

Sundt Generating Station

In 2017, TEP submitted an Application to the Pima County Department of Environmental Quality related to a generation modernization project at Sundt. Under the project outlined in the Application, TEP will place in service 10 Reciprocating Internal Combustion Engines (RICE) units with a total nominal generation capacity of 190 MW. The RICE units are scheduled for commercial operation by the end of the first quarter of 2020.

The RICE units will balance the variability of intermittent renewable energy resources and will replace 162 MW of nominal net generation capacity from Sundt Units 1 and 2, which are less efficient and lack the quick start, fast ramp capabilities of RICE units. TEP will discontinue operation of Sundt Units 1 and 2 prior to commercial operation of the RICE units. We plan to seek recovery of all unrecovered costs for Sundt Units 1 and 2 in our next ACC rate case.

See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information regarding the planned early retirement of Sundt Units 1 and 2.

Gila River Generating Station

In 2017, TEP entered into the Tolling PPA agreement, which includes a three-year option to purchase Gila River Unit 2. TEP's obligations under the agreement were contingent upon SRP's completion of the Gila Acquisition. SRP completed the Gila Acquisition in May 2018. As a result, TEP had $164 million recorded in both Long Term Liabilities—Capital Lease Obligations and Utility Plant Under Capital Leases on the Condensed Consolidated Balance Sheets as of September 30, 2018. The amount reflects the fair value of the unit, which was determined by SRP's purchase price. TEP anticipates exercising its option to purchase Gila River Unit 2 in December 2019 for approximately $164 million. Over the expected 20-month lease term, TEP will pay a monthly demand charge consisting of: (i) a fixed capacity charge of approximately $1 million, and (ii) an operating fee to compensate SRP for the non-fuel costs of operating Gila River Unit 2. TEP recovers the monthly capacity charge and operating fee through the PPFAC.

The additional 550 MW of capacity, power, and ancillary services from the Tolling PPA will allow us to continue to move toward our long-term goal of resource diversification as it will replace coal-fired generation scheduled for early retirement. TEP sells the capacity from the Tolling PPA into the wholesale market on a short-term basis with the associated revenues credited to the PPFAC.

See Note 6 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information regarding the Tolling PPA.

Interest Rates

See Part II, Item 7A in our 2017 Annual Report on Form 10-K/A and Part II, Item 3 of this Form 10-Q for information regarding interest rate risks and its impact on earnings.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

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

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Available Liquidity

(in millions)	September 30, 2018
Cash and Cash Equivalents	$ 18
Amount Available under Revolving Credit Facility [(1)]	235
Total Liquidity	$ 253

(1) TEP's revolving credit facility provides for $250 million of revolving credit commitments with a LOC sublimit of $50 million and a maturity date of October 2022.

Future Liquidity Requirements

We expect to meet all of our financial obligations and other anticipated cash outflows for the foreseeable future. These obligations and anticipated cash outflows include, but are not limited to, dividend payments, debt maturities, and obligations included in the Contractual Obligations and forecasted Capital Expenditures tables reported in our 2017 Annual Report on Form 10-K/A and the material changes summarized below in the respective sections.

Summary of Cash Flows

Effective December 31, 2017, TEP early adopted accounting guidance that requires entities to show the changes in the total of cash, cash equivalents, and restricted cash or restricted cash equivalents on the cash flow statement. The new accounting guidance is applied retrospectively affecting all periods presented.

The table below incorporates the new accounting guidance and presents net cash provided by (used for) operating, investing and financing activities and its effect on cash, cash equivalents, and restricted cash:

	Nine Months Ended September 30,		Increase (Decrease)
(in millions)	2018	2017	Percent
Operating Activities	$352	$337	4.5 %
Investing Activities	(303)	(253)	19.8 %
Financing Activities	(71)	(49)	44.9 %
Net Increase (Decrease)	(22)	35	*
Beginning of Period	50	43	16.3 %
End of Period [(1)]	$28	$78	(64.1)%

* Not meaningful

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

Operating Activities

In the first nine months of 2018, net cash flows from operating activities increased by $15 million compared with the same period in 2017. The increase is primarily due to: (i) higher retail revenue primarily due to an increase in rates as approved in the 2017 Rate Order that took effect February 27, 2017 and favorable weather; and (ii) an increase in recovery of costs as a result of changes in the PPFAC rate. The increase was offset by: (i) the return of savings related to the TCJA to customers; and (ii) $8 million in cash proceeds received from a settlement agreement associated with late-filed TSAs in January 2017.

Investing Activities

In the first nine months of 2018, net cash flows used for investing activities increased by $50 million compared with the same period in 2017 primarily due to an increase in cash paid for capital expenditures.

Financing Activities

In the first nine months of 2018, net cash flows used for financing activities increased by $22 million compared with the same period in 2017 primarily due to an increase in repayments, net of proceeds borrowed, under our revolving credit facility and an increase in dividend paid to UNS Energy in 2018.

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Sources of Liquidity

Short-Term Investments

Our short-term investment policy governs the investment of excess cash balances. We periodically review and update this policy in response to market conditions. As of September 30, 2018, TEP's short-term investments included highly-rated and liquid money market funds.

Access to Revolving Credit Facility

We have access to working capital through a revolving credit agreement with lenders. TEP expects that amounts borrowed under the credit facility will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. As of September 30, 2018, there was $235 million available under the revolving credit commitments and the LOC facility. As of November 1, 2018, TEP had $205 million available under its revolving credit commitments and the LOC facility.

For details of TEP's credit facility see Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 in our 2017 Annual Report on Form 10-K/A.

Debt Financing

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

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

We anticipate issuing approximately $300 million of debt in the fourth quarter of 2018 to: (i) repay callable tax-exempt pollution control bonds backed by an LOC that expires in February 2019; (ii) repay any revolving credit borrowings to ensure adequate revolving credit capacity; and (iii) apply any remaining balances to general corporate purposes.

In connection with the anticipated repayment of the tax-exempt pollution control bonds backed by an LOC, we anticipate the related LOC and 2010 Reimbursement Agreement will be terminated once the bonds are no longer outstanding.

TEP has, from time to time, refinanced or repurchased portions of its outstanding debt before scheduled maturity. Depending on market conditions, we may refinance other debt issuances or make additional debt repurchases in the future. In October 2018, TEP issued a revocable notice to redeem $100 million of variable rate tax-exempt bonds on November 14, 2018. We plan to fund the redemption using cash, revolver borrowings, or a combination thereof.

Credit Ratings

Credit ratings affect our access to capital markets and supplemental bank financing. As of September 30, 2018, credit ratings from S&P Global Ratings and Moody’s Investors Service for our senior unsecured debt were A- and A3, respectively.

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

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

Debt Covenants

Under certain agreements, should TEP fail to maintain compliance with covenants, lenders could accelerate the maturity of all amounts outstanding. As of September 30, 2018, TEP was in compliance with these covenants.

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

Contribution from Parent

TEP received no equity contributions in the third quarter or first nine months of 2018 and 2017.

Dividends Paid to Parent

TEP declared and paid a $40 million dividend to UNS Energy in the third quarter and first nine months of 2018, and a $35 million dividend to UNS Energy in the third quarter and first nine months of 2017.

Master Trading Agreements

TEP conducts its wholesale marketing and risk management activities under certain master trading agreements. Under these agreements, TEP may be required to post credit enhancements in the form of cash or an LOC due to exposures exceeding unsecured credit limits provided to TEP, changes in contract values, changes in TEP's credit ratings, or material changes in TEP's creditworthiness. As of September 30, 2018, TEP had posted no cash or LOCs as credit enhancements with its counterparties.

Capital Expenditures

Our routine capital expenditures include funds used for customer growth, system reinforcement, replacements and betterments, and costs to comply with environmental rules and regulations. Capital expenditures in the first nine months of 2018 were $273 million. Forecasted capital expenditures presented below for years ended December 31 exclude amounts for Allowance for Funds Used During Construction and other non-cash items:

(in millions)	2018	2019	2020	2021	2022
Generation Facilities:					
Renewable Energy (1)	$10	$62	$169	$9	$—
Other Generation Facilities	206	262	76	122	56
Total Generation Facilities	216	324	245	131	56
Transmission and Distribution (2)	183	343	321	194	176
General and Other (3)	120	87	61	53	64
Total Capital Expenditures	$519	$754	$627	$378	$296

(1) Increase related to additional investments in renewable energy that will allow us to continue to move toward our long-term strategy of shifting to a more diverse, sustainable energy portfolio.

(2) Increase due to additional investments in transmission capacity and system reinforcements.

(3) Includes cost for information technology, fleet, facilities, and communication equipment.

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

Contractual Obligations

In the first nine months of 2018, there have been no material changes outside the ordinary course of business to contractual obligations as reported in our 2017 Annual Report on Form 10-K/A, except as noted below:

- In January 2018, we extended the expiration date of a firm transportation agreement from April 2018 to April 2023. See Note 7 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.
- In May 2018, upon completion of the Gila Acquisition, we recorded a new capital lease obligation. See Note 6 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

Off-Balance Sheet Arrangements

Other than the unrecorded contractual obligations reported on the contractual obligations table presented in our 2017 Annual Report on Form 10-K/A, we do not have any arrangements or relationships with entities that are not consolidated into the financial statements.

Income Tax Position

Tax legislation previously in effect included provisions that made qualified property placed in service before 2018 eligible for bonus depreciation for tax purposes. In addition, the Internal Revenue Service had issued guidance related to the treatment of expenditures to maintain, replace, or improve property. These provisions were an acceleration of tax benefits we otherwise would have received over 20 years and created net operating loss carryforwards that may be used to offset future taxable income. As a result, we did not pay any federal or state income taxes in the first nine months of 2018. We offset net operating loss carryforwards against taxable income and do not expect to make federal or state income tax payments until 2024.

Under the TCJA, Alternative Minimum Tax credit carryforwards will be refunded if not used to offset federal income tax liabilities. TEP expects to receive refunds of approximately $12 million in 2019, $6 million in 2020, and $3 million in 2021 and 2022.

In December 2017, the ACC opened a docket requesting that all regulated utilities submit proposals to address passing the benefits of the TCJA through to customers. In April 2018, the ACC Refund Order was approved effective May 1, 2018. The Order provides that we refund customers a total of $36.5 million through a bill credit in 2018. We will continue to return savings to customers through a combination of a bill credit and a regulatory liability. The customer bill credit will account for 75% of the returned savings in 2019, and 50% of the returned savings in 2020 and through the completion of our next rate case. The portion of savings not returned through a bill credit will be deferred as a regulatory liability and returned to customers through our next rate case, which is expected to be filed in 2019.

See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information regarding the TCJA.

Environmental Matters

The Environmental Protection Agency (EPA) regulates the amount of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), particulate matter, mercury and other by-products produced by generation facilities. We may incur additional costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at our generation facilities. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, we are unable to predict the impact of the changing laws and regulations on our operations and consolidated financial results. Complying with these changes may reduce operating efficiency and increase capital and operating costs. TEP will request recovery from its customers of the costs of environmental compliance through cost recovery mechanisms and Retail Rates.

Regional Haze Regulations

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

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

Four Corners Generating Station

In December 2013, Arizona Public Service Company (APS), on behalf of the co-owners of Four Corners, notified the EPA that they have chosen an alternative BART compliance strategy. As a result, APS closed Units 1, 2, and 3 in

December 2013 and agreed to install SCR on Units 4 and 5. TEP owns 7% of Four Corners Units 4 and 5. APS completed the installation of SCR in July 2018. TEP's share of installation costs were approximately $47 million in capital expenditures and $2 million in annual operations and maintenance expenses.

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Navajo Generating Station

In August 2014, the EPA published a final Federal Implementation Plan (FIP) which provides that: (i) one unit at Navajo will be shut down by 2020; (ii) SCR, or the equivalent, will be installed on the remaining two units by 2030; and (iii) conventional coal-fired generation will cease by December 2044. The final BART rule includes options that accommodate potential ownership changes at the facility. The facility had until December 2019 to notify the EPA of how it would comply with the FIP. As a result of the planned early retirement of Navajo, TEP and the co-owners will no longer be responsible for implementing the FIP. See Note 2 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for additional information related to the early retirement of Navajo.

San Juan Generating Station

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

Greenhouse Gas Regulation

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

In October 2017, the EPA issued a proposal to repeal the CPP and in December 2017, the EPA issued an Advance Notice of Proposed Rulemaking soliciting information about the intent to replace the CPP with a rule establishing new emissions guidelines.

In August 2018, the EPA published the proposed Affordable Clean Energy (ACE) rule. The proposed rule is meant to replace the CPP and proposes to rebalance the roles between the states and the EPA. Under the proposed rule, the EPA would set emission guidelines based on the Best System of Emission Reduction (BSER) for Greenhouse Gas (GHG) emissions. The states would then use these emission guidelines to establish standards of performance consistent with the BSER within their jurisdictions considering source specific factors such as the remaining useful life of an individual unit. The proposed ACE rule also includes New Source Review (NSR) reform to incentivize heat-rate improvements that could reduce GHG emissions without triggering costly NSR permit requirements. Only projects that increase a generation facility’s hourly rate of pollutant emissions would be required to undergo a full NSR analysis.

Upon publication of the final rule, the states will have three years to submit plans establishing standards of performance. The EPA has 12 months to act on a complete state submittal. If a state plan is not approved, or a state fails to submit a plan within the allotted three years, the EPA would have two years to issue a federal plan. The public comment period closed October 31, 2018. The EPA anticipates finalizing the rule in early 2019.

TEP will continue to work with other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies as needed. TEP is unable to determine the impact to its facilities until all legal challenges have been resolved and any new regulations have been promulgated.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring disposal of coal ash and other coal combustion residuals (CCR) to be managed as a solid waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) for disposal in landfills and/or surface impoundments. Our share of costs to comply with the rule at Springerville was $2 million. The majority was spent through 2016 on capital expenditures associated with site preparation and installation of the groundwater monitoring well system. We continue to incur additional operating costs for on-going groundwater monitoring and eventual site closure activities. Similarly, we currently estimate our share of costs to be $4 million at Four Corners and $3 million at Navajo. San Juan does not operate any landfills or surface impoundments. San Juan currently disposes of CCR in the surface mine pits of San Juan Mine, adjacent to the plant.

In December 2016, Congress approved the Water Infrastructure Improvements for the Nation (WIIN) Act which authorizes the States to establish permit programs under RCRA for implementing regulation for CCR. In response to the WIIN Act and RCRA rulemaking petitions, the EPA has indicated that it intends to conduct two phases of CCR rule revisions. In July 2018, the EPA signed a Phase 1, Part 1 final rule which: (i) revised groundwater protection standards for rule-specific constituents without

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maximum containment levels; (ii) incorporated risk-based changes under an EPA-approved state permit program or an EPA permit program; and (iii) extended certain closure deadlines. TEP does not anticipate a material impact to operations and financial results from the Phase 1, Part 1 final rule. The EPA anticipates finalizing Phase 1, Part 2 in 2019. Phase 2 is also anticipated to be finalized in 2019.
TEP is currently working with other affected utilities and the Arizona Department of Environmental Quality to explore the possibility of developing a State administered program to enforce CCR regulation.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's Discussion and Analysis of Financial Condition and Results of Operations is based on our Condensed Consolidated Financial Statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires management to apply accounting policies and make estimates, judgments, and assumptions that affect the reported amounts of assets, liabilities, net revenues and expenses, and disclosure of contingent liabilities. Management believes that there have been no significant changes during the nine months ended September 30, 2018, to the items that we disclosed as our critical accounting policies and estimates in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2017 Annual Report on Form 10-K/A.

ACCOUNTING PRONOUNCEMENTS

For a discussion of new accounting pronouncements affecting TEP, see Note 12 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

TEP’s primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. We can enter into interest rate swaps and financing transactions to manage changes in interest rates. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms.
There have been no additional risks and no material changes to market risks disclosed in Part II, Item 7A in our 2017 Annual Report on Form 10-K/A.

ITEM 4. CONTROLS AND PROCEDURES

TEP’s Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer) supervised and participated in TEP’s evaluation of its disclosure controls and procedures as such term is defined under Rule 13(a) – 15(e) or Rule 15(d) – 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this report. Disclosure controls and procedures are controls and procedures designed to ensure that information required to be disclosed in TEP’s periodic reports filed or submitted under the Exchange Act, is recorded, processed, summarized, and reported within the time periods specified in the United States Securities and Exchange Commission’s rules and forms. These disclosure controls and procedures are also designed to ensure that information required to be disclosed by TEP in the reports that it files or submits under the Exchange Act is accumulated and communicated to management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based upon the evaluation performed, TEP’s Chief Executive Officer and Chief Financial Officer concluded that TEP’s disclosure controls and procedures are effective as of September 30, 2018.
While TEP continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting, there has been no change in TEP’s internal control over financial reporting during the quarter ended September 30, 2018, that has materially affected, or is reasonably likely to materially affect, TEP’s internal control over financial reporting.

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PART II

ITEM 1. LEGAL PROCEEDINGS

For a description of certain legal proceedings affecting TEP, refer to Note 7 of Notes to Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

The business and financial results of TEP are subject to numerous risks and uncertainties. As a result, the risks and uncertainties discussed in Part I, Item 1A. Risk Factors in our 2017 Form 10-K/A should be carefully considered. There have been no material changes in the assessment of our risk factors from those set forth in our 2017 Form 10-K/A, except as noted below:

Changes to renewable energy requirements may negatively impact TEP’s business and results of operations.

TEP is subject to an existing state standard that requires most utilities to generate 15% of their annual retail sales of electricity from renewable energy resources by 2025. In November 2018, Arizona voters will consider a ballot initiative that would amend the state constitution. If passed, the initiative would require most Arizona utilities, including TEP, to generate at least 50% of their annual retail electricity sales from renewable energy resources by 2030. Compliance with this new requirement, or other changes to existing renewable energy requirements, could accelerate our long-term resource diversification strategy and significantly increase capital expenditures and operating expenses. These increases could negatively affect the affordability of the rates charged to customers and may negatively impact TEP’s business and results of operations.

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ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
31(a)	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by David G. Hutchens
31(b)	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by Frank P. Marino
*32	Statements of Corporate Officers (pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document

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

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

SIGNATURES

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

		TUCSON ELECTRIC POWER COMPANY
		(Registrant)
Date:	November 1, 2018	/s/ Frank P. Marino
		Frank P. Marino
		Vice President and Chief Financial Officer
		(Principal Financial Officer)