TUCSON ELECTRIC POWER CO
Form 10-Q
November 07, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2014
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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer ¨ Accelerated Filer ¨ Non-accelerated Filerx Smaller Reporting Company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ¨ No x
As of October 20, 2014, Tucson Electric Power Company had 32,139,434 shares of common stock, no par value, outstanding, all of which were held by UNS Energy Corporation.

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DEFINITIONS

The abbreviations and acronyms used in the third quarter 2014 Form 10-Q are defined below:

2010 TEP Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2013 Covenants Agreement	A Lender Rate Mode Covenants Agreement between TEP and the purchaser of $100 million of unsecured tax-exempt bonds that were issued on behalf of TEP in November 2013 and sold in a private placement
2013 TEP Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective July 1, 2013
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
Base O&M	A non-GAAP financial measure that represents the fundamental level of operating and maintenance expense related to our business
Base Rates	The portion of TEP's Retail Rates attributed to generation, transmission, distribution and customer costs. Base Rates exclude authorized charges designed to recover specific costs that are passed through to customers including fuel and purchased energy costs, energy efficiency program costs, certain environmental compliance costs, and a portion of renewable energy costs
Btu	British thermal unit(s)
Cooling Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures
DG	Distributed Generation
DSM	Demand Side Management
ECA	Environmental Compliance Adjustor
EE	Energy Efficiency
Entegra	A subsidiary of Entegra Power Group LLC
FERC	Federal Energy Regulatory Commission
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada
Four Corners	Four Corners Generating Station
GBtu	Billion British thermal units
GWh	Gigawatt-hour(s)
Gila River Unit 3	Unit 3 of the Gila River Generating Station
Heating Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting the average of the high and low daily temperatures from 65
kV	Kilo-volt
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LOC	Letter of Credit
Merger	The acquisition of UNS Energy in 2014 pursuant to the Agreement and Plan of Merger between UNS Energy Corporation and FortisUS Inc.
MMBtu	Million British thermal units
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
OATT	Open Access Transmission Tariff
PNM	Public Service Company of New Mexico

PPFAC	Purchased Power and Fuel Adjustment Clause
REC	Renewable Energy Credit
Regional Haze Rules	Rules promulgated by the EPA to improve visibility at national parks and wilderness areas

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RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility an opportunity to recover its reasonable operating and capital costs and earn a return on its utility plant in service
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction
SJCC	San Juan Coal Company
SNCR	Selective Non-Catalytic Reduction
Springerville	Springerville Generating Station
Springerville Coal Handling Facilities	Coal handling facilities at Springerville used by all four Springerville units
Springerville Coal Handling Facilities Leases	Leases for coal handling facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities	Facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities Leases	Leveraged lease arrangements relating to an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 1	Unit 1 of the Springerville Generating Station
Springerville Unit 1 Leases	Leveraged lease arrangement relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 2	Unit 2 of the Springerville Generating Station
Springerville Unit 3	Unit 3 of the Springerville Generating Station
Springerville Unit 4	Unit 4 of the Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
Sundt Unit 4	Unit 4 of the H. Wilson Sundt Generating Station
TEP	Tucson Electric Power Company, the principal subsidiary of UNS Energy Corporation
TEP Credit Agreement	The TEP Credit Agreement consists of a $200 million revolving credit and LOC facility together with an $82 million LOC facility to support tax-exempt bonds.
Therm	A unit of heating value equivalent to 100,000 Btus
Tri-State	Tri-State Generation and Transmission Association, Inc.
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy
UNS Energy	UNS Energy Corporation
UNS Energy affiliates	Affiliated subsidiaries of UNS Energy including UNS Electric, Inc., UNS Gas, Inc., and Southwest Energy Solutions, Inc.
UNS Gas	UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy

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FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. TEP is including the following cautionary statements to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or for TEP in this Quarterly Report on Form 10-Q. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or 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, estimates, expects, intends, plans, predicts, projects, 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.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed therein. We express our expectations, beliefs, and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management’s 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 II, Item 1A. Risk Factors; Part I, Item 2. Management’s Discussion and Analysis; and other parts of this report. These factors include: state and federal regulatory and legislative decisions and actions; changes in, and compliance with, environmental laws, regulations, decisions and policies that could increase operating and capital costs, reduce generating facility output or accelerate generating facility retirements; regional economic and market conditions which could affect customer growth and energy usage; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets; the performance of the stock market and changing interest rate environment, which affect the value of our pension and other retiree benefit plan assets and the related contribution requirements and expense; unexpected increases in O&M expense; resolution of pending litigation matters; changes in accounting standards; changes in critical accounting estimates; the ongoing impact of mandated energy efficiency and distributed generation initiatives; changes to long-term contracts; the cost of fuel and power supplies; cyber attacks or challenges to our information security; and the performance of TEP's generating plants.

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PART I—FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2014 (Unaudited)	December 31, 2013
	Thousands of Dollars	
ASSETS		
Utility Plant		
Plant in Service	$4,675,441	$4,467,667
Utility Plant Under Capital Leases	747,158	637,957
Construction Work in Progress	173,022	180,485
Total Utility Plant	5,595,621	5,286,109
Less Accumulated Depreciation and Amortization	(1,909,448)	(1,826,977)
Less Accumulated Amortization of Capital Lease Assets	(531,159)	(514,677)
Total Utility Plant—Net	3,155,014	2,944,455
Investments and Other Property		
Investments in Lease Equity	36,086	36,194
Other	36,201	33,488
Total Investments and Other Property	72,287	69,682
Current Assets		
Cash and Cash Equivalents	28,208	25,335
Accounts Receivable—Customer	110,906	80,211
Unbilled Accounts Receivable	49,743	34,369
Allowance for Doubtful Accounts	(5,136)	(4,825)
Accounts Receivable—Due from Affiliates	3,281	6,064
Materials and Supplies	80,475	75,200
Deferred Income Taxes—Current	111,593	70,722
Fuel Inventory	39,027	44,027
Regulatory Assets—Current	66,877	42,555
Derivative Instruments	699	2,137
Other	13,923	12,923
Total Current Assets	499,596	388,718
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	162,872	141,030
Derivative Instruments	212	167
Other Assets	20,587	19,233
Total Regulatory and Other Assets	183,671	160,430
Total Assets	$3,910,568	$3,563,285

See Notes to Condensed Consolidated Financial Statements.

(Continued)

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2014 (Unaudited)	December 31, 2013
	Thousands of Dollars	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	$1,017,778	$925,923
Capital Lease Obligations	68,424	131,370
Long-Term Debt	1,372,369	1,223,070
Total Capitalization	2,458,571	2,280,363
Current Liabilities		
Current Obligations Under Capital Leases	191,951	186,056
Borrowings Under Revolving Credit Facility	35,000	—
Accounts Payable—Trade	83,571	88,556
Accounts Payable—Due to Affiliates	4,099	9,153
Accrued Taxes Other than Income Taxes	53,230	34,485
Accrued Employee Expenses	18,134	24,454
Regulatory Liabilities—Current	37,125	23,701
Accrued Interest	20,043	22,785
Customer Deposits	20,370	21,354
Derivative Instruments	6,664	5,531
Other	8,420	9,244
Total Current Liabilities	478,607	425,319
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	509,062	428,103
Regulatory Liabilities—Noncurrent	302,912	263,270
Pension and Other Postretirement Benefits	79,911	84,936
Derivative Instruments	3,393	5,161
Other	78,112	76,133
Total Deferred Credits and Other Liabilities	973,390	857,603
Commitments, Contingencies & Environmental Matters (Note 5)		
Total Capitalization and Other Liabilities	$3,910,568	$3,563,285

See Notes to Condensed Consolidated Financial Statements.
(Concluded)

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Three Months Ended September 30, 2014	Three Months Ended September 30, 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
(Unaudited) Thousands of Dollars			(Unaudited) Thousands of Dollars	
		Operating Revenues		
$316,387	$310,632	Electric Retail Sales	$760,192	$739,147
37,053	26,563	Electric Wholesale Sales	111,692	90,503
33,971	34,044	Other Revenues	92,658	93,603
387,411	371,239	Total Operating Revenues	964,542	923,253
		Operating Expenses		
89,199	82,065	Fuel	225,163	247,417
49,902	42,477	Purchased Energy	125,423	89,815
5,222	4,940	Transmission and Other PPFAC Recoverable Costs	12,683	7,535
(5,376)	(7,992)	Increase (Decrease) to Reflect PPFAC Recovery Treatment	(20,167)	(5,079)
138,947	121,490	Total Fuel and Purchased Energy	343,102	339,688
112,667	79,335	Operations and Maintenance	273,784	239,170
31,966	30,311	Depreciation	93,857	87,729
6,973	6,118	Amortization	21,449	24,393
11,960	10,808	Taxes Other Than Income Taxes	35,800	32,916
302,513	248,062	Total Operating Expenses	767,992	723,896
84,898	123,177	Operating Income	196,550	199,357
		Other Income (Deductions)		
7	6	Interest Income	181	14
2,024	1,466	Other Income	6,123	3,904
(7,170)	(2,776)	Other Expense	(11,979)	(7,493)
(504)	731	Appreciation (Depreciation) in Fair Value of Investments	375	1,864
(5,643)	(573)	Total Other Income (Deductions)	(5,300)	(1,711)
		Interest Expense		
15,579	13,848	Long-Term Debt	45,326	42,412
1,202	6,323	Capital Leases	9,048	18,821
104	82	Other Interest Expense	557	(86)
(850)	(644)	Interest Capitalized	(2,878)	(1,671)
16,035	19,609	Total Interest Expense	52,053	59,476
63,220	102,995	Income Before Income Taxes	139,197	138,170
23,576	38,828	Income Tax Expense	51,656	41,737
$39,644	$64,167	Net Income	$87,541	$96,433

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Three Months Ended September 30, 2014	Three Months Ended September 30, 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
(Unaudited) Thousands of Dollars			(Unaudited) Thousands of Dollars	
		Comprehensive Income		
$39,644	$64,167	Net Income	$87,541	$96,433
		Other Comprehensive Income		
		Net Changes in Fair Value of Cash Flow Hedges:		
697	700	net of income tax expense of $450 and $458		
		net of income tax expense of $1,117 and $1,412	1,672	2,156
		Supplemental Executive Retirement Plan (SERP) Benefit Amortization:		
25	68	net of income tax expense of $16 and $42		
		net of income tax expense of $46 and $127	74	205
722	768	Total Other Comprehensive Income, Net of Taxes	1,746	2,361
$40,366	$64,935	Total Comprehensive Income	$89,287	$98,794

See Notes to Condensed Consolidated Financial Statements.

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TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2014	2013
	(Unaudited)	
	Thousands of Dollars	
Net Income	$87,541	$96,433
Adjustments to Reconcile Net Income To Net Cash Flows from Operating Activities		
Depreciation Expense	93,857	87,729
Amortization Expense	21,449	24,393
Amortization of Deferred Debt-Related Costs included in Interest Expense	1,959	1,831
Use of Renewable Energy Credits for Compliance	15,129	11,766
Deferred Income Taxes	53,991	53,381
Pension and Retiree Expense	10,236	14,909
Pension and Retiree Funding	(12,989)	(26,118)
Share-Based Compensation Expense	5,010	2,239
Allowance for Equity Funds Used During Construction	(4,983)	(2,923)
LFCR Revenue	(8,350)	—
Decrease to Reflect PPFAC Recovery	(20,167)	(5,079)
Fortis Acquisition Direct Customer Benefit	18,870	—
PPFAC Reduction - 2013 TEP Rate Order	—	3,000
Changes in Assets and Liabilities which Provided (Used) Cash Exclusive of Changes Shown Separately		
Accounts Receivable	(45,758)	(41,227)
Materials and Fuel Inventory	(274)	14,955
Accounts Payable	(472)	(8,678)
Income Taxes	(25)	(10,681)
Interest Accrued	(3,849)	1,008
Taxes Other Than Income Taxes	18,745	17,405
Other	(8,652)	19,836
Net Cash Flows – Operating Activities	221,268	254,179
Cash Flows from Investing Activities		
Capital Expenditures	(227,153)	(180,451)
Purchase of Intangibles—Renewable Energy Credits	(22,047)	(17,552)
Return of Investments in Springerville Lease Debt	—	9,104
Restricted Cash Released	—	4,500
Other, net	12,883	4,656
Net Cash Flows—Investing Activities	(236,317)	(179,743)
Cash Flows from Financing Activities		
Proceeds from Borrowings Under Revolving Credit Facility	190,000	78,000
Repayments of Borrowings Under Revolving Credit Facility	(155,000)	(78,000)
Proceeds from Issuance of Long-Term Debt	149,168	—
Payments of Capital Lease Obligations	(165,145)	(99,621)
Dividends Paid to UNS Energy	—	(20,000)
Payment of Debt Issue/Retirement Costs	(1,652)	(1,022)
Other, net	551	1,250
Net Cash Flows—Financing Activities	17,922	(119,393)

Net Increase (Decrease) in Cash and Cash Equivalents	2,873	(44,957)
Cash and Cash Equivalents, Beginning of Year	25,335	79,743
Cash and Cash Equivalents, End of Period	$28,208	$34,786

See Note 8 for supplemental cash flow information.
See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDER'S EQUITY

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
	(Unaudited) Thousands of Dollars				
Balances at December 31, 2013	$888,971	$(6,357)	$49,185	$(5,876)	$925,923
Net Income			87,541		87,541
Other Comprehensive Income, net of taxes				1,746	1,746
Other	2,568				2,568
Balances at September 30, 2014	$891,539	$(6,357)	$136,726	$(4,130)	$1,017,778

See Notes to Condensed Consolidated Financial Statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION
Tucson Electric Power Company (TEP) is a regulated utility that generates, transmits and distributes electricity to approximately 415,000 retail electric 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. In addition, TEP operates Springerville Generating Station (Springerville) Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agricultural Improvement and Power District (SRP). 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), which is a leader in the North American electric and gas utility business.
FORTIS ACQUISITION OF UNS ENERGY
On December 11, 2013, UNS Energy, the parent of TEP, announced that it had entered into an Agreement and Plan of Merger (Merger) to be acquired by Fortis for $60.25 per share of UNS Energy common stock in cash. The acquisition contemplated by this agreement was completed effective August 15, 2014.
Prior to completion of the Merger, UNS Energy obtained the approval of its shareholders, the Federal Energy Regulatory Commission (FERC), and the Arizona Corporation Commission (ACC). The ACC's approval was subject to certain stipulations, including, but not limited to, the following:

- TEP will provide credits on retail customers' bills totaling $19 million over five years: approximately $6 million in year one and $3 million annually in years two through five. The monthly bill credits will be applied each year from October through March effective October 1, 2014;
- TEP, along with UNS Energy and its other affiliated subsidiaries, will adopt certain ring-fencing and corporate governance provisions;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for a period of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital. The ratios used to determine the dividend restrictions will be calculated each calendar year and reported to the ACC annually beginning on April 1, 2016; and
- Fortis making an equity investment totaling $220 million to UNS Energy and its regulated subsidiaries, including TEP. Following the close of the Merger, Fortis exceeded the investment requirement by contributing $37 million to UNS Energy on August 15, 2014 and $200 million to UNS Energy on October 10, 2014. On October 10, 2014, UNS Energy contributed $175 million of the investment to TEP.

As a result of the Merger being completed, TEP recorded approximately $15 million through August 2014 as its allocated share of merger-related expenses, in addition to the customer bill credits discussed above. Merger-related expenses include investment banker fees, legal expenses, and accelerated expenses for certain share-based compensation awards.
SHARE-BASED COMPENSATION EXPENSE
Completion of the Merger resulted in accelerated vesting and expense recognition of all outstanding non-vested UNS Energy share-based awards that would otherwise have been recognized over remaining vesting periods through February 2017. TEP recognized approximately $2 million of expense in the third quarter of 2014 due to the accelerated vesting of the awards. TEP recorded total share-based compensation expense of $4 million for the three months ended September 30, 2014 and $1 million for the three months ended September 30, 2013. For the nine months ended September 30, 2014 and 2013, TEP recorded $5 million and $3 million of share-based compensation expense, respectively. In August 2014, UNS Energy settled all outstanding share-based compensation awards in cash.
BASIS OF PRESENTATION
We prepared our condensed consolidated financial statements according to generally accepted accounting principles in the United States of America (GAAP) and the Securities and Exchange Commission's (SEC) interim reporting requirements. These condensed consolidated financial statements exclude some information and footnotes required by GAAP and the SEC for annual financial statement reporting. These condensed consolidated financial statements

should be read in conjunction with the consolidated financial statements and footnotes in our 2013 Annual Report on Form 10-K.

The condensed consolidated financial statements are unaudited, but, in management's opinion, include all recurring adjustments necessary for a fair presentation of the results for the interim periods presented. Because weather and other factors cause seasonal fluctuations in sales, our quarterly results are not indicative of annual operating results. TEP did not reflect the impacts of acquisition accounting in its financial statements. All adjustments of assets and liabilities to fair value and the resultant goodwill associated with the Merger were recorded by FortisUS Inc., a wholly owned subsidiary of Fortis.

As a result of the Fortis Merger, TEP has elected to change its method of reporting cash flows from the direct to the indirect method to conform to the presentation method elected by Fortis. Certain amounts from prior periods have been reclassified to conform to the current period presentation.

REVISION OF PRIOR PERIOD BALANCE SHEETS

TEP revised its December 31, 2013 balance sheet to correct an error in the classification of capital lease obligations and related deferred income taxes. The correction increased current capital lease obligations and decreased noncurrent capital lease obligations by $18 million and increased current deferred tax assets and noncurrent deferred tax liabilities by $7 million. We do not believe the misclassification was material to the previously issued financial statements.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2014, we adopted accounting guidance that:

- requires an entity to recognize and disclose in the financial statements its obligation from a joint and several liability arrangement as the sum of the amount the entity agreed with its co-obligors that it will pay and any additional amount the entity expects to pay on behalf of its co-obligors. The adoption of this guidance did not have a material impact on our disclosures, financial condition, results of operations, or cash flows.
- impacts the financial statement presentation of unrecognized tax benefits when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. Although adoption and prospective application of this guidance impacted how such items are classified on our balance sheets, such change was not material. Additionally, there were no material changes in our results of operations or cash flows.

NOTE 2. REGULATORY MATTERS

The ACC and the FERC each regulate portions of the utility accounting practices and rates of TEP.

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

COST RECOVERY MECHANISMS

Purchased Power and Fuel Adjustment Clause

In April 2014, the ACC approved a Purchased Power and Fuel Adjustment Clause (PPFAC) rate for TEP of 0.10 cents per kWh for the period May through September 2014 and 0.50 cents per kWh for the period October 2014 through March 2015. TEP's PPFAC rate was a credit of approximately 0.14 cents per kWh for the period July 2013 through April 2014.

San Juan Mine Fire Insurance Proceeds

In September 2011, a fire at the underground mine providing coal to San Juan Generating Station (San Juan) caused interruptions to mining operations and resulted in increased fuel costs. The 2013 TEP Rate Order required TEP to defer incremental fuel costs of $10 million from recovery under the PPFAC pending final resolution of an insurance claim by the San Juan Coal Company and distribution of insurance proceeds to San Juan participants. As of September 30, 2014, TEP has received insurance settlement proceeds of $8 million and expects to receive substantially all of the outstanding balance in the fourth quarter. The proceeds offset the deferred costs and are reflected in our cash flow statements as an other operating cash receipt. TEP expects to recover any remaining fuel costs, not reimbursed by insurance, through its PPFAC.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Environmental Compliance Adjustor

The 2013 TEP Rate Order provided an Environmental Compliance Adjustor (ECA) to recover the return on and of qualified investments to comply with environmental standards required by federal or other governmental agencies. The ECA rate of 0.0049 cents per kWh became effective on May 1, 2014. TEP expects to recognize ECA revenues of less than $1 million in 2014.

Energy Efficiency Standards

TEP is required to implement cost-effective Demand Side Management (DSM) programs to comply with the ACC's Energy Efficiency (EE) Standards. The EE Standards provide for a DSM surcharge to recover, from retail customers, the costs to implement DSM programs as well as a performance incentive. In the first nine months of 2014, TEP recorded a DSM performance incentive of $2 million that is included in Electric Retail Sales in the TEP Income Statement.

Lost Fixed Cost Recovery Mechanism

The Lost Fixed Cost Recovery (LFCR) mechanism provides recovery of certain non-fuel costs that would go unrecovered due to lost retail kWh sales as a result of implementing ACC approved EE programs and distributed generation (DG) targets. For recovery of lost fixed costs, TEP is required to file an annual LFCR adjustment request with the ACC for costs related to the prior year, and recovery is subject to a year-over-year cap of 1% of the company's total retail revenues.

TEP recorded, in Electric Retail Sales, LFCR revenues of $8 million in the first nine months of 2014 related to reductions in retail kWh sales for 2013 and 2014. We recognize LFCR revenue when verifiable regardless of when the lost retail kWh sales occur.

The ACC approved TEP's annual LFCR recovery request for lost fixed costs incurred in 2013 of approximately $5 million. The approved rates, of approximately 0.41% of retail revenue for EE and approximately 0.31% of retail revenue for DG, became effective August 2014.

NOTE 3. RELATED PARTY TRANSACTIONS

TEP engages in various transactions with affiliated subsidiaries of UNS Energy including UNS Electric, Inc., (UNS Electric), UNS Gas, Inc. (UNS Gas) and Southwest Energy Solutions, Inc. (SES) (collectively, UNS Energy affiliates). These transactions include sales and purchases of power, common cost allocations, and the provision of corporate and other labor related services. Additionally, TEP and UNS Electric are planning the joint purchase of a generating station unit. See Note 6.

The following table summarizes related party transactions:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Wholesale Sales - TEP to UNS Electric [1]	$2	$—	$3	$1
Wholesale Sales - UNS Electric to TEP [1]	2	—	3	1
Control Area Services - TEP to UNS Electric [2]	1	1	2	3
Common Costs - TEP to UNS Energy Affiliates [3]	3	3	10	9
Supplemental Workforce - SES to TEP [4]	4	4	12	11
Corporate Services and Other Labor Charges - TEP to UNS Energy Affiliates [5]	3	4	7	10
Corporate Services - UNS Energy Affiliates to TEP [5]	—	—	1	1

(1) TEP and UNS Electric sell power to each other at prevailing market prices.

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

(3)

Common costs (systems, facilities, etc.) are allocated on a cost-causative basis and recorded as revenue by TEP. Management believes this method of allocation is reasonable.

(4) SES provides supplemental workforce and meter-reading services to TEP. Amounts are based on costs of services performed, and management believes that the charges for the services are reasonable.

(5) All Corporate Services (finance, accounting, tax, legal and information technology) and other labor services are directly assigned to the benefiting entity at a fully burdened cost when possible; other costs are allocated using the Massachusetts' Formula, an industry accepted method of allocating common costs to affiliated entities.

At September 30, 2014 and December 31, 2013, our Balance Sheets include the following intercompany balances:

	Balances at	
	September 30, 2014	December 31, 2013
	Millions of Dollars	
Receivables from Related Parties		
UNS Electric	$2	$3
UNS Gas	1	2
UNS Energy	—	1
Total Due from Related Parties	$3	$6
Payables to Related Parties		
SES	$3	$2
UNS Electric	1	—
UNS Energy	—	7
Total Due to Related Parties	$4	$9

NOTE 4. DEBT AND CAPITAL LEASE OBLIGATIONS

We summarize below the significant changes to our debt and capital lease obligations from those reported in our 2013 Annual Report on Form 10-K.

SPRINGERVILLE COAL HANDLING FACILITIES CAPITAL LEASE PURCHASE COMMITMENT

In April 2014, TEP notified the owner participants and their lessors that TEP has elected to purchase their undivided ownership interests in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million upon the expiration of the lease term in April 2015. Due to TEP’s purchase commitment, in April of 2014, TEP recorded an increase to both Utility Plant Under Capital Leases and Current Obligations Under Capital Leases on its balance sheet in the amount of $109 million, which represented the present value of the total purchase commitment.

TEP previously agreed with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities Leases were not renewed, TEP would exercise the purchase option under those contracts. Upon TEP's purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million, and Tri-State is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. No amounts have been recorded for these commitments from SRP and Tri-State at September 30, 2014.

2014 UNSECURED NOTES ISSUED

In March 2014, TEP issued $150 million of 5.0% unsecured notes due March 2044. TEP may redeem the notes prior to September 15, 2043, with a make-whole premium plus accrued interest. After September 15, 2043, TEP may redeem the notes at par plus accrued interest. TEP used the net proceeds to repay approximately $90 million on the outstanding borrowings under the revolving credit facility with the remaining proceeds used for general corporate purposes. The unsecured notes contain a limitation on the amount of secured debt that TEP may have outstanding.

TEP CREDIT AGREEMENT

The TEP Credit Agreement consists of a $200 million revolving credit and LOC facility together with an $82 million LOC facility to support tax-exempt bonds. As of September 30, 2014, there is $149 million available under the revolving credit

facility. The TEP Credit Agreement expires in November 2016. As of October 20, 2014, TEP had $185 million available under its revolving credit facility.

TEP provided, in the second quarter of 2014, a LOC for $15 million to the seller of Gila River Unit 3 to satisfy a condition of the purchase agreement. TEP's borrowing capacity under the TEP Credit Agreement is reduced by $15 million until the Gila River transaction closes and the LOC is terminated. See Note 6.

COVENANT COMPLIANCE

At September 30, 2014, we were in compliance with the terms of our loan and credit agreements.

NOTE 5. COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL MATTERS

COMMITMENTS

In addition to those reported in our 2013 Annual Report on Form 10-K, TEP entered into the following long-term commitments through September 30, 2014:

	2014	2015	2016	2017	2018	Thereafter	Total
	Millions of Dollars						
Fuel, Including Transportation	$—	$9	$9	$10	$10	$42	$80
Purchased Power	—	18	—	—	—	—	18
Renewable Power Purchase Agreements (PPA)(2)	6	5	5	5	5	60	86
Capital Lease Obligations(1)	—	120	—	—	—	—	120
Total Purchase Commitments	$6	$152	$14	$15	$15	$102	$304

(1) In April 2014, TEP entered into agreements to purchase certain Springerville Coal Handling Facilities leased interests. See Note 4.

(2) In July 2014, TEP entered into a 20-year PPA with a renewable energy generation facility that achieved commercial operation in July 2014. TEP is obligated to purchase 100% of the output from this facility. The amounts in the table also reflect updated estimated annual production for existing contracts which increased the minimum annual payment obligations.

CONTINGENCIES

Planned Purchase of Gas-Fired Generation Facility

In 2013, TEP and UNS Electric, an affiliate of TEP, entered into an agreement to purchase a gas-fired generation facility. See Note 6.

Claims Related to San Juan Generating Station

San Juan Coal Company (SJCC) operates an underground coal mine in an area where certain gas producers have oil and gas leases with the federal government, the State of New Mexico, and private parties. These gas producers allege that SJCC’s underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan Generating Station (San Juan), which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot estimate the impact of any future claims by these gas producers on the cost of coal at San Juan.

In August 2013, the Bureau of Land Management (BLM) proposed regulations that, among other things, redefine the term “underground mine” to exclude high-wall mining operations and impose a higher surface mine coal royalty on high-wall mining. SJCC utilized high-wall mining techniques at its surface mines prior to beginning underground mining operations in January 2003. If the proposed regulations become effective, SJCC may be subject to additional royalties on coal delivered to San Juan between August 2000 and January 2003 totaling approximately $5 million of which TEP’s proportionate share would approximate $1 million. TEP cannot predict the final outcome of the BLM’s proposed regulations.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against Arizona Public Service Company (APS) and the other Four Corners Generating Station (Four Corners) participants alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. In January 2012, EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners. Among other things, the plaintiffs seek to have the court issue an order to cease operations at Four Corners until any required PSD permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint. In August 2014, APS submitted a counteroffer with revised settlement terms. The joint participants have agreed to have the matter stayed until November 2014 to make continued progress toward a final agreement that would resolve this matter without further litigation.

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. TEP's estimated share of the settlement offer submitted by APS in August 2014 is less than $1 million. TEP cannot predict the final outcome of the claims relating to Four Corners, and, due to the general and non-specific nature of the claims and the indeterminate scope and nature of the injunctive relief sought for this claim, TEP cannot determine estimates of the range of costs at this time.

In May 2013, the New Mexico Taxation and Revenue Department issued a notice of assessment for coal severance tax, penalties, and interest totaling $30 million to the coal supplier at Four Corners. In December 2013, the coal supplier and Four Corners' operating agent filed a claim contesting the validity of the assessment on behalf of the participants in Four Corners, who will be liable for their share of any resulting liabilities. TEP's share of the assessment based on its ownership of Four Corners is approximately $1 million. The New Mexico Taxation and Revenue Department and APS started settlement negotiations in July 2014. TEP cannot predict the outcome or timing of resolution of this claim.

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final 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 $44 million upon expiration of the coal supply agreements, which expire between 2017 and 2031. The reclamation liability (present value of future liability) recorded was $21 million at September 30, 2014 and $18 million at December 31, 2013.

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

TEP's PPFAC allows us to pass through most fuel costs, including final reclamation costs, to 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.

Discontinued Transmission Project

TEP and UNS Electric had initiated a project to jointly construct a 60-mile transmission line from Tucson, Arizona to Nogales, Arizona in response to an order by the ACC to UNS Electric to improve the reliability of electric service in Nogales. At this time, TEP and UNS Electric will not proceed with the project based on the cost of the proposed 345-kV line, the difficulty in reaching agreement with the United States Forest Service on a path for the line, and concurrence by the ACC that recent transmission additions by TEP and UNS Electric support elimination of this project. TEP and UNS Electric plan to keep the path approved in the line siting matter in contemplation of using a greater part of the route to serve future customers and to address reliability needs. As part of the 2013 TEP Rate Order, TEP agreed to seek recovery of the project costs from the FERC before seeking rate recovery from the ACC. In 2012, TEP wrote off $5 million of the capitalized costs believed not probable of recovery and recorded a regulatory asset of $5 million for the balance deemed probable of recovery in TEP's next FERC rate case.

Performance Guarantees

The participants in each of the remote generating stations in which TEP participates, including TEP, have guaranteed certain performance obligations of the other participants. Specifically, in the event of payment default of a participant, the non-defaulting participants have agreed to bear a proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generating capacity of the defaulting participants. As of September 30, 2014, there have been no such payment defaults under any of the remote generating station agreements. TEP's joint participation agreements expire in 2016 through 2046.

ENVIRONMENTAL MATTERS

Environmental Regulation

The Environmental Protection Agency (EPA) limits the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx), particulate matter, mercury and other emissions released into the atmosphere by power plants. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its ratepayers.

Hazardous Air Pollutant Requirements

In February 2012, the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from power plants. Based on the EPA's final Mercury and Air Toxics (MATS) rules, additional emission control equipment will be required by April 2015. TEP, as operator of Springerville and Sundt, and the operator of Navajo have received extensions until April 2016 to comply with the MATS rules. TEP's share of the estimated costs to comply with the MATS rules includes the following:

Estimated Mercury Emissions Control Costs:	Navajo	Springerville(1)
	Millions of Dollars	
Capital Expenditures	$1	$5
Annual O&M Expenses	1	1

(1) Total capital expenditures and annual O&M expenses represent amounts for both Springerville Units 1 & 2, with estimated costs split equally between the two units. TEP will own 49.5% of Springerville Unit 1 upon close of the lease option purchases in January 2015; after the completion of such purchases, third party owners will be responsible for 50.5% of environmental costs attributable to Springerville Unit 1. TEP will continue to be responsible for 100% of environmental costs attributable to Springerville Unit 2.

TEP expects Four Corners, Sundt, and San Juan's current emission controls to be adequate to comply with the EPA's MATS rules. A study determined that Four Corners' emission controls are adequate. Therefore, TEP expects no additional capital expenditures or O&M expenses will be incurred to comply. Although expected to be compliant, Sundt would be required to install additional monitoring equipment, at an estimated cost of less than $1 million, to continue to burn coal after the MATS rules become effective.

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as Best Available Retrofit Technology (BART) for certain industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. The rules call 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 the Navajo Indian Reservation, they are not subject to state oversight; the EPA oversees regional haze planning for these power plants. In the western U.S., Regional Haze BART determinations have focused on controls for NOx, often resulting in a requirement to install selective catalytic reduction (SCR). Complying with the EPA’s BART rules, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. BART provisions of Regional Haze Rules requiring emission control upgrades do not apply to Springerville because the BART rules apply to plants built prior to Springerville. TEP cannot predict the ultimate outcome of these matters. TEP's estimated costs involved in meeting these rules are:

Estimated NOx Emissions Control Costs:	Navajo (1)	San Juan (2)	Four Corners (3)	Sundt (4)

	Millions of Dollars			
Capital Expenditures	$42	$35	$35	$12
Annual O&M Expenses	1	1	2	5-6

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(1) In August 2014, the EPA published a final rule approving a better-than-BART plan wherein: one unit at Navajo will be shut down by 2020; SCR (or the equivalent) will be installed on the remaining two units by 2030; and conventional coal-fired generation will cease by December 2044. In addition, the installation of SCR technology could increase particulates which may require that baghouses be installed. TEP owns 7.5% of Navajo. TEP's share of the capital cost of baghouses in addition to the SCR costs reflected in the table above is approximately $43 million with O&M on the baghouses expected to be less than $1 million per year.

(2) In October 2014, the EPA published a final rule approving a state plan covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017 and the installation of selective non-catalytic reduction (SNCR) on Units 1 and 4 by January 2016. Corresponding to that action, the EPA withdrew the previously applicable FIP addressing the same requirements. Prior to the shutdown of any units in San Juan, PNM must obtain New Mexico Public Regulation Commission approval. If Unit 2 is retired early, TEP expects to request ACC approval to recover all costs associated with the early closure of the unit. TEP owns 50% of San Juan Unit 2. At September 30, 2014, the net book value of TEP's share in San Juan Unit 2 was $111 million.

(3) In December 2013, APS, on behalf of the co-owners of Four Corners, notified the EPA that they have chosen an alternative BART compliance strategy; as a result, APS closed Units 1, 2, and 3 in December 2013 and has agreed to the installation of SCR on Units 4 & 5 by July 2018. TEP owns 7% of Four Corners Units 4 and 5.

(4) In June 2014, the EPA issued a final rule that would require TEP to either (i) install SNCR and dry sorbent injection technology on Unit 4 by mid-2017 or (ii) eliminate the use of coal by the end of 2017 as a better-than-BART alternative. TEP is required to notify the EPA of its decision by March 2017. At September 30, 2014, the net book value of the Sundt coal handling facilities was $17 million. If the coal handling facilities are retired early, TEP expects to request ACC approval to recover all the remaining costs of the coal handling facilities.

NOTE 6. PLANNED PURCHASE OF GAS-FIRED GENERATION FACILITY

In December 2013, TEP and UNS Electric, an affiliate of TEP, entered into a purchase agreement with a subsidiary of Entegra to purchase Gila River Unit 3 for $219 million, subject to certain closing adjustments. Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 MW, is located in Gila Bend, Arizona. TEP expects to purchase a 75% undivided interest in Gila River Unit 3 (413 MW) for approximately $164 million, and UNS Electric expects to purchase the remaining 25% undivided interest (137 MW) for approximately $55 million. In October 2014, the FERC issued an order authorizing the transaction. The closing of the transaction remains subject to certain other closing conditions and finalizing various closing documents. TEP and UNS Electric expect the transaction to close in December 2014.

In June 2014, TEP provided a letter of credit (LOC) for $15 million to the seller of Gila River Unit 3 to satisfy a condition of the purchase agreement. The seller is entitled to draw upon the LOC and apply such amount as liquidated damages if it has validly terminated the purchase agreement as a result of misrepresentations by TEP and UNS Electric or the failure of TEP and UNS Electric to close the transaction when the closing conditions have been satisfied. Upon the close of the transaction, the LOC will be canceled. In August 2014, Entegra filed a prepackaged Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the District of Delaware. In September 2014, Entegra's Chapter 11 bankruptcy plan was confirmed. TEP does not expect the bankruptcy to impact the purchase of Gila River Unit 3.

NOTE 7. EMPLOYEE BENEFIT PLANS

Net periodic benefit plan cost includes the following components:

	Pension Benefits		Other Retiree Benefits	
	Three Months Ended September 30,			
	2014	2013	2014	2013
	Millions of Dollars			

Service Cost	$2	$3	$1	$1
Interest Cost	4	4	—	—
Expected Return on Plan Assets	(5)	(5)	—	—
Actuarial Loss Amortization	1	2	—	—
Net Periodic Benefit Cost	$2	$4	$1	$1

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Pension Benefits		Other Retiree Benefits	
	Nine Months Ended September 30,			
	2014	2013	2014	2013
	Millions of Dollars			
Service Cost	$7	$8	$3	$3
Interest Cost	12	11	2	2
Expected Return on Plan Assets	(16)	(14)	(1)	(1)
Actuarial Loss Amortization	3	6	—	—
Net Periodic Benefit Cost	$6	$11	$4	$4

NOTE 8. SUPPLEMENTAL CASH FLOW INFORMATION
NON-CASH TRANSACTIONS
In April 2014, TEP recorded an increase of $109 million to both Utility Plant Under Capital Leases and Current Obligations Under Capital Leases due to TEP's commitment to purchase leased interests in April 2015. See Note 4.
In August 2013, TEP recorded an increase of $39 million to both Utility Plant Under Capital Leases and Capital Lease Obligations due to TEP's commitment to purchase leased interests in Springerville Unit 1 in January 2015.
In March 2013, TEP issued $91 million of tax-exempt bonds and used the proceeds to redeem debt using a trustee. Since the cash flowed through a trust account, the issuance and redemption of debt resulted in a non-cash transaction.

NOTE 9. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS
We categorize our assets and liabilities accounted for at fair value into the three-level hierarchy based on inputs used to determine the fair value. Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in an active market. Level 2 inputs include quoted prices for similar assets or liabilities, quoted prices in non-active markets, and pricing models whose inputs are observable, directly or indirectly. Level 3 inputs are unobservable and supported by little or no market activity. Transfers between levels are recorded at the end of a reporting period. There were no transfers between levels in the periods presented.
FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS
The following tables present, by level within the fair value hierarchy, TEP’s assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets[5]	Net Amount
	September 30, 2014 Millions of Dollars					
Assets						
Cash Equivalents[1]	$10	$10	$—	$—	$—	$10
Restricted Cash[1]	2	2	—	—	—	2
Rabbi Trust Investments[2]	25	—	25	—	—	25
Energy Contracts - Regulatory Recovery[3]	1	—	1	—	(1)	—
Total Assets	38	12	26	—	(1)	37
Liabilities						
Energy Contracts - Regulatory Recovery[3]	(5)	—	(2)	(3)	1	(4)
Energy Contracts - Cash Flow Hedge[3]	(1)	—	—	(1)	—	(1)
Interest Rate Swaps[4]	(4)	—	(4)	—	—	(4)
Total Liabilities	(10)	—	(6)	(4)	1	(9)
Net Total Assets (Liabilities)	$28	$12	$20	$(4)	$—	$28

	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets[5]	Net Amount
	December 31, 2013 Millions of Dollars					
Assets						
Cash Equivalents[1]	$—	$—	$—	$—	$—	$—
Restricted Cash[1]	2	2	—	—	—	2
Rabbi Trust Investments[2]	22	—	22	—	—	22
Energy Contracts - Regulatory Recovery[3]	2	—	1	1	(1)	1
Total Assets	26	2	23	1	(1)	25
Liabilities						
Energy Contracts - Regulatory Recovery[3]	(2)	—	—	(2)	1	(1)
Energy Contracts - Cash Flow Hedge[3]	(1)	—	—	(1)	—	(1)
Interest Rate Swaps[4]	(7)	—	(7)	—	—	(7)
Total Liabilities	(10)	—	(7)	(3)	1	(9)
Net Total Assets (Liabilities)	$16	$2	$16	$(2)	$—	$16

(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 balance sheets. Restricted Cash is included in Investments and Other Property – Other on the balance sheets.

(2) Rabbi Trust Investments include amounts related to deferred compensation and Supplement Executive Retirement Plan (SERP) benefits held in mutual and money market funds valued at quoted prices traded in active markets. These investments are included in Investments and Other Property – Other on the balance sheets.

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

(4) Interest Rate Swaps still held are valued based on the 6-month London Interbank Offered Rate (LIBOR). An interest rate swap valued based on the Securities Industry and Financial Markets Association Municipal swap index matured in September 2014. These interest rate swaps are included in Derivative Instruments on the balance sheets.

(5) All energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk. We have presented the effect of offset by counterparty; however, we present derivatives on a gross basis on the balance sheets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DERIVATIVE INSTRUMENTS

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

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

For both power and gas prices we obtain quotes from brokers, major market participants, exchanges, or industry publications and rely on our own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe that the market information provided is reflective of market conditions as of the time and date indicated.

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

We estimate the fair value of our gas options using a Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, interest rates, and forward price curves. In the first half of 2013, we also used this pricing model to value our power options.

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

The inputs and our assessments of the significance of a particular input to the fair value measurements require judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. We review the assumptions underlying our price curves monthly.

Cash Flow Hedges

We enter into interest rate swaps to mitigate the exposure to volatility in variable interest rates on debt. The interest rate swap agreements expire through January 2020. We also have a power purchase swap to hedge the cash flow risk associated with a long-term power supply agreement. The power purchase swap agreement expires in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities and amounts reclassified to earnings are reported in the statements of other comprehensive income and Note 11. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $2 million.

Financial Impact of Energy Contracts

We record unrealized gains and losses on energy contracts that are recoverable through the PPFAC on the balance sheets as a regulatory asset or a regulatory liability rather than reporting the transaction in the income statements or in the statements of other comprehensive income, as shown in following tables:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets)/Liabilities	$(6)	$(1)	$(4)	$(2)

Realized gains and losses on settled contracts are fully recoverable through the PPFAC. At September 30, 2014, we have energy contracts that will settle through the third quarter of 2017.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivative Volumes
The volumes associated with our energy contracts were as follows:

	September 30, 2014	December 31, 2013
Power Contracts GWh	842	779
Gas Contracts GBtu	20,595	9,615

Level 3 Fair Value Measurements
The following table provides quantitative information regarding significant unobservable inputs in TEP's Level 3 fair value measurements:

	Valuation Approach	Fair Value at September 30, 2014 Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input	
		Millions of Dollars				
Forward Power Contracts	Market approach	$—	$(3)	Market price per MWh	$27.50	$43.50
Gas Option Contracts	Option model	—	(1)	Market price per MMbtu	$3.67	$4.24
				Gas volatility	24.88%	40.62%
Level 3 Energy Contracts		$—	$(4)			

	Valuation Approach	Fair Value at December 31, 2013 Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input	
		Millions of Dollars				
Forward Power Contracts	Market approach	$—	$(3)	Market price per MWh	$27.00	$48.25
Gas Option Contracts	Option model	1	—	Market price per MMbtu	$3.88	$4.32
				Gas volatility	25.05%	35.07%
Level 3 Energy Contracts		$1	$(3)			

Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude of the change and the direction of the change for each input. The impact of changes to fair value, including changes from unobservable inputs, are subject to recovery or refund through the PPFAC mechanism and are reported as a regulatory asset or regulatory liability, or as a component of other comprehensive income, rather than in the income statement.
The following tables present a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended September 30, 2014	2013
	Millions of Dollars	
Balances at June 30	$—	$(1)
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(4)	(1)

Settlements	—	—
Balances at September 30	$(4)	$(2)
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/(Liabilities) Still Held at the End of the Period	$(2)	$—

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Nine Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Balances at December 31	$(2)	$—
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(3)	(2)
Settlements	1	—
Balances at September 30	$(4)	$(2)
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/(Liabilities) Still Held at the End of the Period	$(2)	$(1)

CREDIT RISK

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

We have contractual agreements for energy procurement and hedging activities that contain certain provisions requiring each company to post collateral under certain circumstances. These circumstances include: exposures in excess of unsecured credit limits provided to the Regulated Utilities; credit rating downgrades; or a failure to meet certain financial ratios. In the event that such credit events were to occur, we would have to provide certain credit enhancements in the form of cash or LOCs to fully collateralize our exposure to these counterparties.

We consider the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position after incorporating collateral posted by counterparties and allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts.

Material adverse changes could trigger credit risk-related contingent features. At September 30, 2014, the value of derivative instruments in a net liability position under contracts with credit risk-related contingent features, including contracts under the normal purchase normal sale exception, was $17 million. At September 30, 2014 , TEP had no cash collateral posted and less than $1 million LOCs as credit enhancements with its counterparties and did not hold any collateral from its counterparties. The additional collateral to be posted if credit-risk contingent features were triggered would be $17 million.

FINANCIAL INSTRUMENTS NOT CARRIED AT FAIR VALUE

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

- The carrying amounts of our current maturities of long-term debt and amounts outstanding under our credit agreements approximate the fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For Investment in Lease Equity, we estimate the price at which an investor would realize a target internal rate of return. Our estimates include: the mix of debt and equity an investor would use to finance the purchase; the cost of debt; the required return on equity; and income tax rates. The estimate assumes a residual value based on an appraisal of Springerville Unit 1 conducted in 2011. No impairment has been recorded as TEP expects to recover the full carrying value in retail rates.
- For Long-Term Debt, we use quoted market prices, when available, or calculate the present value of remaining cash flows at the balance sheet date. When calculating present value, we use current market rates for bonds with similar

characteristics such as credit rating and time-to-maturity. We consider the principal amounts of variable rate debt outstanding to be reasonable estimates of the fair value. We also incorporate the impact of our own credit risk using a credit default swap rate.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The carrying values recorded on the balance sheets and the estimated fair values of our financial instruments include the following:

		September 30, 2014		December 31, 2013	
	Fair Value Hierarchy	Carrying Value	Fair Value	Carrying Value	Fair Value
		Millions of Dollars			
Assets:					
Investment in Lease Equity	Level 3	$36	$26	$36	$25
Liabilities:					
Long-Term Debt	Level 2	1,372	1,444	1,223	1,214

NOTE 10. INCOME TAXES

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

	Three Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Federal Income Tax Expense at Statutory Rate	$22	$36
State Income Tax Expense, Net of Federal Deduction	3	5
Federal/State Tax Credits	(2)	(1)
Other	1	(1)
Total Federal and State Income Tax Expense	$24	$39

	Nine Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Federal Income Tax Expense at Statutory Rate	$49	$48
State Income Tax Expense, Net of Federal Deduction	6	6
Federal/State Tax Credits	(4)	(2)
Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset	—	(11)
Other	1	1
Total Federal and State Income Tax Expense	$52	$42

Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset

Renewable energy assets are eligible for investment tax credits. We reduce the income tax basis of those qualifying assets by half of the related investment tax credit. Historically, the difference between the income tax basis of the assets and the book basis under GAAP was recorded as a deferred tax liability with an offsetting charge to income tax expense in the year the qualifying asset was placed in service. In June 2013, we recorded a regulatory asset and corresponding reduction of income tax expense of $11 million to recover previously recorded income tax expense through future rates as a result of the 2013 TEP Rate Order. The regulatory asset will be amortized as income tax expense as the qualifying assets are depreciated.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

NOTE 11. RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME BY COMPONENT

The reclassifications from Accumulated Other Comprehensive Income (AOCI) by component are as follows:

Details About Accumulated Other Comprehensive Income Components	Amount Reclassified from Other Comprehensive Income				Affected Line Item in the Income Statement
	Three Months Ended September 30,		Nine Months Ended September 30,		
	2014	2013	2014	2013	
	Thousands of Dollars				
Realized Losses on Cash Flow Hedges					
Interest Rate Swaps - Debt	$(291)	$(296)	$(882)	$(871)	Interest Expense Long-Term Debt
Interest Rate Swaps - Capital Leases	(451)	(612)	(1,649)	(1,820)	Interest Expense Capital Leases
Commodity Contracts	(478)	(556)	(621)	(747)	Purchased Energy/Purchased Power
Income Tax Benefit	546	579	1,238	1,360	
Realized Losses on Cash Flow Hedges, Net of Taxes	(674)	(885)	(1,914)	(2,078)	
Amortization of SERP					
Prior Service Cost and Net Loss	(40)	(110)	(119)	(332)	Other Expense
Income Tax Benefit	15	42	45	127	
Amortization, Net of Taxes	(25)	(68)	(74)	(205)	
Total Reclassifications from Other Comprehensive Income	$(699)	$(953)	$(1,988)	$(2,283)	

NOTE 12. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In April 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update that limits the circumstances under which a disposal may be reported as a discontinued operation and requires new disclosures. This guidance will be effective in the first quarter of 2015. We do not expect the adoption of this guidance to have an impact on the presentation of our financial statements or our disclosures.

In May 2014, the FASB issued an accounting standards update that will eliminate the transaction- and industry-specific revenue recognition guidance under current U.S. GAAP and replace it with a principles based approach for determining revenue recognition. We will be required to adopt the new guidance retrospectively for annual and interim periods beginning January 1, 2017; early adoption is not permitted. We are evaluating the impact to our financial statements and disclosures.

In August 2014, the FASB issued guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods beginning January 1, 2017; early adoption is permitted. TEP does not expect the adoption of this guidance to have an impact on its disclosures.

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ITEM 2. – MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

- outlook and strategies;
- operating results during the third quarter and first nine months of 2014 compared with the same periods of 2013;
- factors affecting our results and outlook;
- liquidity, capital needs, capital resources, and contractual obligations;
- dividends; and
- critical accounting estimates.

OVERVIEW

Tucson Electric Power Company (TEP) is a vertically integrated, regulated utility that generates, transmits and distributes electricity to approximately 415,000 retail electric 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. In addition, TEP operates Springerville Generating Station (Springerville) Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agricultural Improvement and Power District (SRP). 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) which is the largest investor-owned gas and electric distribution utility in Canada.

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

FORTIS ACQUISITION OF UNS ENERGY

On December 11, 2013, UNS Energy, the parent of TEP, announced that it had entered into an Agreement and Plan of Merger (Merger) to be acquired by Fortis for $60.25 per share of UNS Energy Common Stock in cash. The acquisition contemplated by this agreement was completed effective August 15, 2014.

Prior to completion of the Merger, UNS Energy obtained the approval of its shareholders, the Federal Energy Regulatory Commission (FERC), and the Arizona Corporation Commission (ACC). The ACC's approval was subject to certain stipulations, including, but not limited to, the following:

- TEP will provide credits on retail customers' bills totaling approximately $19 million over five years: $6 million in year one and $3 million annually in years two through five. The monthly bill credits will be applied each year from October through March effective October 1, 2014;
- TEP, along with UNS Energy and its other affiliated subsidiaries, will adopt certain ring-fencing and corporate governance provisions;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for a period of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital. The ratios used to determine the dividend restrictions will be calculated each calendar year and reported to the ACC annually beginning on April 1, 2016; and
- Fortis making an equity investment totaling $220 million to UNS Energy and its regulated subsidiaries, including TEP. Following the close of the Merger, Fortis exceeded the investment requirement by contributing $37 million to UNS Energy on August 15, 2014 and $200 million to UNS Energy on October 10, 2014. On October 10, 2014, UNS Energy contributed $175 million of the investment to TEP.

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As a result of the Merger being completed, TEP recorded approximately $15 million through August 2014 as its allocated share of merger-related expenses, in addition to the customer bill credits discussed above. Merger-related expenses include investment banker fees, legal expenses, and accelerated expenses for certain share-based compensation awards.

OUTLOOK AND STRATEGIES

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

- Completing the purchases of Gila River Unit 3 and certain interests in Springerville Unit 1, which are both key components of our long-term diversification strategy for our generation portfolio. The focus of our resource strategy is to provide long-term rate stability for our customers, mitigate environmental impacts, comply with regulatory requirements, and leverage our existing utility infrastructure.
- Developing strategic responses to new environmental regulations and potential new legislation, including proposed carbon emission standards to reduce greenhouse gas emissions from existing power plants. We are evaluating TEP's existing mix of generation resources and defining steps to achieve environmental objectives that protect the financial stability of our utility business.
- Strengthening the underlying financial condition of TEP by achieving constructive regulatory outcomes, improving our capital structure and our credit ratings, and promoting economic development in our service territory.
- Focusing on our core utility business through operational excellence, investing in utility rate base, emphasizing customer service, and maintaining a strong community presence.
- Developing strategic responses to the evolving utility business that includes renewable energy, distributed generation (DG), and energy efficiency (EE) that protect the financial stability of our business while providing benefits for our customers.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations for the three and nine month periods ended September 30, 2014 and 2013.

Third quarter of 2014 compared with the third quarter of 2013

TEP reported net income of $40 million in the third quarter of 2014 compared with net income of $64 million in the third quarter of 2013. The following factors affected the period over period change in TEP’s results:

- a $39 million pre-tax increase in Base O&M that includes: $19 million for retail customer bill credits agreed to as a condition of closing the Merger; $14 million for TEP's allocated share of merger-related expenses including acquisition transaction fees and accelerated share-based compensation expense recognized under change in control provisions; and $6 million primarily due to higher maintenance expenses at a jointly owned generating station and increased incentive compensation;
- a $3 million pre-tax decrease in retail margin revenues due to a 1.3% decrease in retail kWh sales; and
- a $2 million pre-tax increase in depreciation and amortization expense due to an increase in utility plant in service; offset by
- a $4 million pre-tax decrease in interest expense primarily due to a reduction in the balance of capital lease obligations; and
- a $15 million decrease in income tax expense primarily due to lower pre-tax income. The effective tax rate was approximately 37% in each period.

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Nine months ended September 30, 2014 compared with the nine months ended September 30, 2013

TEP reported net income of $88 million in the first nine months of 2014 compared with net income of $96 million in the first nine months of 2013. The following factors affected the period over period change in TEP’s results:

- a $39 million pre-tax increase in Base O&M that includes: $19 million for retail customer bill credits agreed to as a condition of closing the Merger; $15 million for TEP's allocated share of merger-related expenses including acquisition transaction fees and accelerated share-based compensation expense recognized under change in control provisions; and $5 million primarily due to higher maintenance expenses at a jointly owned generating station and increased incentive compensation;
- a $5 million pre-tax increase in depreciation and amortization expense resulting from an increase in asset base in the current period, offset by the impact of lower average depreciation rates as approved in the TEP 2013 Rate Order;
- a $3 million pre-tax increase in taxes other than income taxes due in part to an increase in property tax rates and higher property values; partially offset by
- a $32 million increase in Retail Margin Revenues, primarily due to a non-fuel base rate increase that was effective on July 1, 2013 and includes $8 million of LFCR revenues recorded in the first nine months of 2014 related to reductions in retail kWh sales due to EE programs and DG implemented in 2014 and 2013. See Factors Affecting Results of Operations, 2013 TEP Rate Order, below, and Note 2;
- a $3 million non-recurring pre-tax charge to fuel and purchase energy expense in June 2013 as a result of the 2013 TEP Rate Order;
- a $3 million pretax increase in the margin on long-term wholesale sales due in part to an increase in the market price for wholesale power;
- a $7 million pre-tax decrease in interest expense largely due to a reduction in the balance of capital lease obligations; and
- a $10 million increase in income tax expense based on relatively flat period over period pre-tax earnings due primarily to the impact of an $11 million tax benefit related to a regulatory asset recorded in June 2013 to recover previously recorded income tax expense through future rates. See Note 10.

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Utility Sales and Revenues

The table below provides a summary of retail kWh sales, revenues, and weather data during the third quarter of 2014 and 2013:

	Three Months Ended September 30,		Increase (Decrease)	
	2014	2013	Amount	Percent[1]
Energy Sales, kWh (in Millions):				
Electric Retail Sales:				
Residential	1,334	1,354	(20)	(1.5)%
Commercial	642	652	(10)	(1.5)%
Industrial	602	621	(19)	(3.1)%
Mining	287	275	12	4.4%
Other	7	7	—	—%
Total Electric Retail Sales	2,872	2,909	(37)	(1.3)%
Retail Margin Revenues (in Millions):				
Residential	$100	$102	$(2)	(2.0)%
Commercial	61	63	(2)	(3.2)%
Industrial	30	31	(1)	(3.2)%
Mining	11	11	—	—%
Other	—	—	—	NM
Total by Customer Class	202	207	(5)	(2.4)%
LFCR Revenues	2	—	2	NM
Total Retail Margin Revenues (Non-GAAP)[2]	204	207	(3)	(1.4)%
Fuel and Purchased Power Revenues	101	94	7	7.4%
RES, DSM, and ECA Revenues	11	11	—	—%
Total Retail Revenues (GAAP)	$316	$312	$4	1.3%
Average Retail Margin Rate (Cents / kWh):[1]				