TUCSON ELECTRIC POWER CO
Form 10-K
February 18, 2016

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

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

For the fiscal year ended December 31, 2015
OR

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

For the transition period from to .
Commission File Number 1-5924
TUCSON ELECTRIC POWER COMPANY
(Exact name of registrant as specified in its charter)

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

88 East Broadway Boulevard, Tucson, AZ 85701
(Address of principal executive offices)(Zip Code)
Registrant's telephone number, including area code: (520) 571-4000
Securities registered pursuant to Section 12(b) of the Exchange Act: None
Securities registered pursuant to Section 12(g) of the Exchange Act:
Common Stock, without par value
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.
Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).
Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No ¨

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ¨	Accelerated Filer ¨	Non-accelerated Filer	x	Smaller Reporting Company ¨

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates: None
As of February 17, 2016, Tucson Electric Power Company had 32,139,434 shares of common stock, no par value, outstanding, all of which were held by UNS Energy Corporation, an indirect wholly owned subsidiary of Fortis Inc.

Documents incorporated by reference: None

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DEFINITIONS

The abbreviations and acronyms used in the 2015 Form 10-K are defined below:

2010 Credit Agreement	The 2010 Credit Agreement consisted of a $200 million revolving credit and letter of credit facility together with an $82 million LOC facility to support tax-exempt bonds; terminated in October 2015 when replaced by the 2015 Credit Agreement
2010 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
2014 Credit Agreement	The 2014 Credit Agreement consisted of a $130 million term loan commitment and a $70 million revolving credit commitment; terminated in June 2015
2015 Credit Agreement	The 2015 Credit Agreement provides for a $250 million revolving credit and letter of credit facility with a sublimit of $50 million; the credit agreement matures in 2020 and replaced the 2010 Credit Agreement
2015 TEP Rate Case	A pending general rate case filed with the ACC by TEP in November 2015 requesting new rates effective January 1, 2017
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
Base Rates	The portion of 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 power costs, energy efficiency program costs, certain environmental compliance costs, and a portion of renewable energy costs
Cooling Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures
DSM	Demand Side Management
EE Standards	Energy Efficiency Standards
FERC	Federal Energy Regulatory Commission
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada, whose principal executive offices are located at Fortis Place, Suite 1100, 5 Springdale Street, St. John's, NL A1E 0E4
Four Corners	Four Corners Generating Station
GAAP	Generally Accepted Accounting Principles in the United States
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(s)
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LOC	Letter of Credit
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station

PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
ppb	Parts per billion

REC	Renewable Energy Credit
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 Springerville Units 1 and 2
Springerville Common Facilities Leases	Leveraged lease arrangements relating to an undivided one-half interest in 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
Third-Party Owners	Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners)
Tri-State	Tri-State Generation and Transmission Association, Inc.
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy
UNS Energy	UNS Energy Corporation, the parent company of TEP, whose principal executive offices are located at 88 East Broadway Boulevard, Tucson, Arizona 85701
UNS Gas	UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy

FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. Tucson Electric Power Company (TEP) 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 Annual Report on Form 10-K. 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, believes, estimates, expects, intends, may, plans, predicts, projects, would, and similar expressions. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All such forward-looking statements, whether written or oral, and whether made by or on behalf of TEP, are expressly qualified by these cautionary statements and any other cautionary statements which may accompany the forward-looking statements. In addition, TEP disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report, except as may otherwise be required by the federal securities laws.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed therein. We express our 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 I, Item 1A. Risk Factors; Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations; and other parts of this report. These factors include: state and federal regulatory and legislative decisions and actions; 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; changes in energy consumption by retail customers; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets; the performance of the stock market and changing interest rate environment, which affect the value of our pension and other retiree benefit plan assets and the related contribution requirements and expense; the inability to make additions to our existing high voltage transmission system; unexpected increases in O&M expense; resolution of pending litigation matters; changes in accounting standards; changes in 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; the ability to obtain coal from our suppliers; cyber attacks or challenges to our information security; and the performance of TEP's generating plants.

PART I

ITEM 1. BUSINESS

GENERAL

Tucson Electric Power Company (TEP) and its predecessor companies have served the greater Tucson metropolitan area for over 100 years. TEP was incorporated in the State of Arizona in 1963. TEP is a regulated electric utility company serving approximately 417,000 retail customers. TEP’s service territory covers 1,155 square miles and includes a population of approximately one million people in Pima County, as well as parts of Cochise County. TEP's principal business operations include generating, transmitting, and distributing electricity to its retail customers. In addition to retail sales, TEP sells electricity, transmission, and ancillary services to other utilities, municipalities, and energy marketing companies on a wholesale basis. TEP is subject to comprehensive state and federal regulation. The regulated electric utility operation is TEP's only segment.

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

REGULATED UTILITY OPERATIONS

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

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

CUSTOMERS

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

	2015			2014			2013		
Electric Sales - GWh									
Residential	3,724	28	%	3,727	29	%	3,867	30	%
Commercial	2,124	15	%	2,170	17	%	2,187	17	%
Industrial (Non-mining)	2,063	15	%	2,098	16	%	2,114	17	%
Mining	1,109	8	%	1,137	9	%	1,079	9	%
Other	33	—	%	33	—	%	32	—	%
Total Electric Retail Sales	9,053	66	%	9,165	71	%	9,279	73	%
Electric Wholesale Sales - Long-Term	750	5	%	618	5	%	605	5	%
Electric Wholesale Sales - Short-Term	3,928	29	%	3,082	24	%	2,859	22	%
Total Electric Sales	13,731	100	%	12,865	100	%	12,743	100	%
Average Number of Retail Customers:									
Residential	376,439	90	%	374,204	90	%	370,925	90	%
Commercial	38,253	9	%	38,079	9	%	37,783	9	%
Industrial (Non-mining)	588	—	%	604	—	%	622	—	%
Mining	4	—	%	4	—	%	4	—	%
Other	1,857	1	%	1,858	1	%	1,843	1	%
Total Retail Customers	417,141	100	%	414,749	100	%	411,177	100	%

Retail Customers

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

Local, regional, and national economic factors impact the growth in the number of customers in TEP’s service territory. In each of the past five years, TEP’s average number of retail customers increased by less than 1%. TEP expects the number of retail customers to increase at a rate of approximately 1% in 2016 based on estimated population growth in its service territory.

TEP’s retail sales volume in 2015 was approximately 9,053 gigawatt-hours (GWh), which is a decrease of 3% from 2011 levels. During the past five years, local economic conditions combined with state requirements to reduce retail sales through energy efficiency and distributed generation have resulted in lower sales volumes and lower use per customer.

Two of TEP’s largest retail customers are in the copper mining industry. TEP’s GWh sales to mining customers depend on a variety of factors including commodity prices, the electricity rate paid by mining customers, and the mines’ development of their own electric generation resources. TEP’s GWh sales to mining customers decreased by 2% in 2015 as a result of mining curtailments due to declining commodity prices. In 2016, TEP expects additional curtailments to certain mining customers based on announced plans and current commodity prices. TEP cannot predict how long the commodity prices will remain low or the impact prices will have on mining production.

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

Wholesale Sales

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

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

Long-Term Wholesale Sales

Long-term wholesale contracts cover periods of one year or greater. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers. In 2015, TEP’s primary long-term contracts were with Salt River Project Agriculture Improvement and Power District (SRP), Shell Energy North America (Shell), the Navajo Tribal Utility Authority (NTUA), and TRICO Electric Cooperative (TRICO). The SRP contract expires in May 2016, the Shell contract expires in December 2017, the NTUA contract expires in December 2022, and the TRICO contract expires in December 2024.

In November 2015, TEP entered into a long-term wholesale sales contract with Navopache Electric Cooperative (Navopache). Delivery of power begins January 1, 2017 and expires in December 2041.

Short-Term Wholesale Sales

Forward contracts commit TEP to sell a specified amount of capacity or energy at a specified price over a given period of time, typically for one-month or three-month periods. TEP also engages in short-term sales by selling energy in the daily or hourly markets at fluctuating spot market prices and making other non-firm energy sales. The majority of our revenues from short-term wholesale sales offset fuel and purchased power costs and are passed through to TEP’s retail customers. TEP uses short-term wholesale sales as part of its hedging strategy to reduce customer exposure to fluctuating power prices.

Competition

Retail Customers

TEP is the primary electric service provider to retail customers within its service territory and operates under a certificate of public convenience and necessity as regulated by the ACC. TEP is subject to competition from customer-sited distributed generation, energy efficiency, and other emerging technologies. TEP is experiencing increases in the levels of customer-sited solar arrays and the use of net energy metering, which allows self-generating retail customers to use their excess generation to offset a portion of their future electricity consumption at the full retail rate.

Wholesale Sales

The Federal Energy Regulatory Commission (FERC) regulates rates for wholesale power sales and transmission services. TEP's wholesale activity primarily consists of Short-Term Wholesale Sales to manage fuel and purchased power supplies to serve retail customer energy requirements and Long-Term Wholesale Sales to optimize generation capacity. As a result of its wholesale activity, TEP competes with other utilities, power marketers and independent power producers in the wholesale markets.

GENERATING FACILITIES

As of December 31, 2015 TEP owned 2,501 megawatts (MW) of nominal generating capacity, as set forth in the following table. Nominal capacity is based on unit design net output.

Generating Source	Unit No.	Location	Date In Service	Resource Type	Capacity MW	Operating Agent	TEP's Share %	TEP's Share MW [1]
Springerville Station	1	Springerville, AZ	1985	Coal	387	TEP	49.5	192
Springerville Station	2	Springerville, AZ	1990	Coal	406	TEP	100	406
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	785	APS	7.0	55
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	75.0	413
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100	104
Sundt Station [2]	4	Tucson, AZ	1967	Gas	156	TEP	100	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100	50
DeMoss Petrie		Tucson, AZ	2001	Gas	75	TEP	100	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100	94
Springerville Solar Station		Springerville, AZ	2002-2014	Solar	16	TEP	100	16
Tucson Solar Projects		Tucson, AZ	2010-2014	Solar	13	TEP	100	13
Ft. Huachuca Project		Ft. Huachuca, AZ	2014	Solar	17	TEP	100	17
Total TEP Capacity [3]								2,501

(1) Capacity measured in direct current (DC).

(2) Sundt Station Unit 4 is a multi-fuel generating facility that can be operated on either coal or natural gas as a primary fuel source. In August 2015, TEP exhausted its existing coal supply at Sundt Station Unit 4 and plans to continue operating Sundt Station Unit 4 with natural gas as a primary fuel source. The table above reflects the nominal generating capacity assuming the unit is fueled by natural gas. Refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Environmental Matters of this Form 10-K for additional information related to environmental matters impacting Unit 4 of the H. Wilson Sundt Generating Station (Sundt).

(3) Excludes 913 MW of additional resources, which consist of certain capacity purchases and interruptible retail load.

Springerville Generating Station

TEP has a 49.5% ownership interest in Unit 1 of the Springerville Generating Station (Springerville Unit 1) and operates the remaining interests in Springerville Unit 1 on behalf of third parties, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners). The Owner Trustees and Co-Trustees are responsible for their share of operating and capital costs for the facility. See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Third-Party Owners.

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

TEP's other interests in the Springerville Generating Station (Springerville) include: (i) 49.5% undivided interest in certain common facilities used by Springerville Unit 1; and (ii) an 83% ownership interest in the Springerville Coal Handling Facilities.

Springerville Common Facilities Leases

The leveraged lease arrangements relating to a 50% undivided interest in certain Springerville Common Facilities (Springerville Common Facilities Leases) used by Springerville Unit 2, which expire in 2017 and 2021, have fair market value renewal options as well as fixed-price purchase options. The fixed prices to acquire the leased interests in the Springerville Common Facilities are $38 million in 2017 and $68 million in 2021.

See Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources for additional information regarding the capital leases.

Springerville Units 3 and 4

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

Sundt Generating Station

Sundt and the internal combustion turbines located in Tucson are designated as must-run generation facilities. Must-run generation units are required to run in certain circumstances to maintain distribution system reliability and to meet local load requirements.

Renewable Energy Resources

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

Owned Renewable Resources

As of December 31, 2015, TEP owned 46 MW of photovoltaic (PV) solar generating capacity. In 2016, TEP plans to complete an additional solar project adding 5 MW of PV solar generating capacity. The solar generating facilities are located on properties held under easements and leases. In December 2015, TEP also acquired a 5 MW concentrated solar project which does not increase capacity but displaces the equivalent amount of steam produced by burning fossil fuel.

Renewable Power Purchase Agreements

As of December 31, 2015, TEP has renewable PPAs for 175 MW of capacity measured in direct current (DC) from solar resources, 80 MW of capacity measured in alternating current (AC) from wind resources and 4 MW of capacity measured in AC from a landfill gas generation plant. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future period.

Power Purchases

TEP purchases power from other utilities and power marketers. TEP may enter into contracts to purchase: (i) energy under long-term contracts to serve retail load and long-term wholesale contracts; (ii) capacity or energy during periods of planned outages or for peak summer load conditions; and (iii) energy for resale to certain wholesale customers under load and resource management agreements.

TEP typically uses generation from its gas-fired units, supplemented by power purchases, to meet the summer peak demands of its retail customers. Some of these power purchases are price-indexed to natural gas. Due to its increasing seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure with fixed price contracts for a maximum of three years. TEP also purchases energy in the daily and hourly markets to meet higher than anticipated demands, to cover unplanned generation outages, or when doing so is more economical than generating its own energy.

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

PEAK DEMAND AND FUTURE RESOURCES

Peak Demand

(in MW)	2015	2014	2013	2012	2011
Retail Customers	2,222	2,218	2,230	2,290	2,334
Firm Sales to Other Utilities	638	673	484	286	322
Coincident Peak Demand (A)	2,860	2,891	2,714	2,576	2,656
Total Generating Resources	2,452	2,240	2,240	2,267	2,262
Other Resources [1]	913	932	775	683	1,009
Total TEP Resources (B)	3,365	3,172	3,015	2,950	3,271
Total Margin (B) – (A)	505	281	301	374	615
Reserve Margin (% of Coincident Peak Demand)	18 %	10 %	11 %	15 %	23 %

(1) Other Resources include firm power purchases and interruptible retail and wholesale loads.

The chart above shows the relationship over a five-year period between peak demand and energy resources. Total margin is the difference between total energy resources and coincident peak demand, and the reserve margin is the ratio of margin to coincident peak demand. The reserve margin in 2015 was in compliance with reliability criteria set forth by the Western Electricity Coordinating Council, a regional council of North American Reliability Corporation (NERC).

Peak demand occurs during the summer months due to the cooling requirements of retail customers. Retail peak demand varies from year-to-year due to weather, economic conditions, and other factors. Retail peak demand has primarily declined over the five-year period due to weak economic conditions and the implementation of energy efficiency programs and distributed generation.

Forecasted retail peak demand for 2016 is 2,109 MW compared with actual peak demand of 2,222 MW in 2015. TEP’s 2016 estimated retail peak demand is based on weather patterns observed over a 10-year period and other factors, including estimates of customer usage and planned curtailment of mining customers. TEP believes existing generation capacity and PPAs are sufficient to meet expected demand in 2016 and established reserve margin criteria.

Future Resources

At December 31, 2015, approximately 49% of TEP's generating capacity was fueled by coal. Existing and proposed federal environmental regulations, as well as potential changes in state regulation, may increase the cost of operating coal-fired generating facilities. TEP is executing strategies and evaluating additional steps to reduce its dependency on coal generation while still meeting its peak load requirements. In August 2015, TEP exhausted its existing coal supply at Unit 4 of the H. Wilson Sundt Generating Station (Sundt Unit 4). TEP expects to continue operating Sundt Unit 4 on natural gas as a primary fuel source.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations for additional information regarding TEP's generating facilities.

FUEL SUPPLY

Fuel and Purchased Power Summary

Resource information is provided below:

	Average Cost per kWh (cents per kWh)			Percentage of Total kWh Resources					
	2015	2014	2013	2015		2014		2013	
Coal	2.44	2.50	2.66	60	%	68	%	75	%
Gas	3.35	4.99	4.57	19	%	9	%	8	%
Purchased Power	4.05	4.79	4.83	21	%	23	%	17	%
All Sources	3.31	3.64	3.54	100	%	100	%	100	%

Coal

The coal used for electric generation is low-sulfur, bituminous or sub-bituminous coal from mines in Arizona and New Mexico. The table below provides information on the existing coal contracts that supply our generating stations. The average cost of coal per million metric British thermal unit (MMBtu), including transportation, was $2.34 in 2015, $2.43 in 2014, and $2.57 in 2013.

Station	Coal Supplier	2015 Coal Consumption (tons in 000s)	Contract Expiration	Avg. Sulfur Content	Coal Obtained From
Springerville [(1)]	Peabody CoalSales	2,676	2020	1.0%	Lee Ranch Mine/El Segundo Mine
Four Corners [(2)]	BHP Billiton	378	2031	0.7%	Navajo Mine
San Juan [(3)]	San Juan Coal Co.	1,079	2022	0.8%	San Juan Mine
Navajo	Peabody CoalSales	510	2019	0.6%	Kayenta Mine

(1) Peabody has a pending sale of the Lee Ranch Mine/El Segundo Mine to Bowie Resources Partners.

(2) Beginning in July 2016 through June 2031, the coal for Four Corners will be purchased from the Navajo Transitional Energy Company (NTEC). NTEC purchased the mine located near Four Corners from BHP Billiton and will begin overseeing the mine operation in 2016.

(3) BHP Billiton sold San Juan Coal Co. to Westmoreland Coal Company, effective January 31, 2016.

TEP Operated Generating Facilities

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

TEP no longer uses coal as a primary fuel source for Sundt Unit 4.

Coal Generating Facilities Operated by Others

TEP also participates in jointly-owned coal-fired generating facilities at the Four Corners Generating Station (Four Corners), the Navajo Generating Station (Navajo), and the San Juan Generating Station (San Juan). Four Corners, which is operated by Arizona Public Service Company (APS), and San Juan, which is operated by Public Service Company of New Mexico (PNM), are mine-mouth generating stations located adjacent to the coal reserves. Navajo, which is operated by SRP, obtains its coal supply from the nearby Kayenta coal mine and receives deliveries on a dedicated electric rail delivery system. Effective January 31, 2016, Westmoreland Coal Company purchased San Juan Coal Company (SJCC) from BHP Billiton and has also agreed to a new coal supply agreement extending through June 30, 2022. TEP expects coal reserves available to these three jointly-owned generating facilities to be sufficient for the remaining lives of the stations.

Natural Gas Supply

TEP uses generation from its facilities fueled by natural gas, in addition to energy from its coal-fired facilities and purchased power, to meet the summer peak demands of its retail customers and local reliability needs. The average cost of natural gas per MMBtu, including transportation, was $3.49 in 2015, $5.17 in 2014, and $4.55 in 2013.

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TEP purchases capacity from El Paso Natural Gas (EPNG) for transportation from the San Juan and Permian Basins to its Sundt plant under firm transportation agreements. TEP also purchases firm gas transportation for Gila River Unit 3 from EPNG and Transwestern Pipeline Co., and for Luna Generating Station (Luna) from EPNG. TEP purchases gas from Southwest Gas Corporation under a retail tariff for North Loop’s 94 MW of internal combustion turbines and receives distribution service under a transportation agreement for DeMoss Petrie, a 75 MW internal combustion turbine.

TRANSMISSION AND DISTRIBUTION

TEP's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. TEP's transmission system, together with contractual rights on other transmission systems, enables TEP to integrate and access generation resources to meet its customer load requirements. TEP's transmission and distribution systems included approximately 2,170 miles of transmission lines, and 7,557 miles of distribution lines as of December 31, 2015.

In 2015, TEP completed construction and placed into service a 500-Kilo-volt (kV) transmission line extending from the Pinal Central substation to TEP’s Tortolita substation northwest of Tucson. The transmission line was built to provide additional transmission capacity from the Palo Verde area into TEP’s northern service territory.

RATES AND REGULATION

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 debt, transactions with affiliated parties, and other utility matters. The ACC also enacts other regulations and policies that can affect business decisions and accounting practices. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

2015 Rate Case

In November 2015, TEP filed a general rate case with the ACC requesting a Base Rate increase of $110 million and various rate design changes. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this From 10-K and Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations for key provisions regarding the 2015 Rate Case.

Purchased Power and Fuel Adjustment Clause

The Purchased Power and Fuel Adjustment Clause (PPFAC) allows TEP to recover its fuel, transmission, and purchased power costs, including demand charges, and the costs of contracts for hedging fuel and purchased power costs for its retail customers. The PPFAC consists of a forward component and a true-up component.

The true-up component reconciles any over/under collected amounts from the preceding 12-month period and is credited to or recovered from customers in the subsequent year.

TEP’s PPFAC also includes the recovery of the following costs and/or credits: lime costs used to control sulfur dioxide (SO_2) emissions at Springerville; sulfur credits received from TEP’s coal suppliers; broker fees; revenues from short-term wholesale sales; and all of the proceeds from the sale of SO_2 allowances.

At December 31, 2015, TEP had over-collected fuel and purchased power costs by $18 million.

Renewable Energy Standards and Tariff

The ACC’s RES requires TEP and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. Affected utilities must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out those plans is recovered from retail customers through the RES surcharge until such costs are reflected in TEP’s Base Rates. The associated lost revenues attributable to meeting distributed generation targets will be partially recovered through the Lost Fixed Cost Recovery Mechanism (LFCR). See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

In July 2015, TEP submitted its application for the 2016 RES implementation plan that includes a budget of $57 million, which will be partially offset by applying approximately $9 million of previously recovered carryover funds. TEP proposed to recover $48 million through the RES surcharge. The budget will fund the following: the above market cost of renewable energy purchases; previously awarded performance-based incentives for customer installed distributed generation; depreciation and a return on TEP's investments in company-owned solar projects; and various other program costs. TEP expects to receive a decision on the application in the first half 2016. TEP expects to recognize approximately $9 million of revenue in 2016 as a return on company-owned solar projects.

The percentage of retail kilowatt-hour (kWh) sales attributable to the 2015 RES renewable energy requirement was 8.6%, exceeding the overall 2015 requirement of 5.0%. TEP expects to meet the 2016 RES renewable energy requirement of 6.0% of retail kWh sales. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain distributed generation Renewable Energy Credits (REC), which are used to demonstrate compliance with the distributed generation requirement, TEP has requested a waiver of the RES distributed generation requirements in its 2016 RES implementation plan.

Energy Efficiency Standards

In 2010, the ACC approved new Energy Efficiency Standards (EE Standards) designed to require electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. Since the implementation of the EE Standards, TEP’s cumulative annual energy savings are approximately 9.3% of retail kWh sales in 2015. Compliance with the EE Standards is determined through the ACC's review of the company's annual energy efficiency implementation plan.

In February 2016, the ACC approved TEP’s 2016 energy efficiency implementation plan. Under the 2016 plan, TEP has been approved to recover approximately $14 million from retail customers and will offer customers new and existing DSM programs. Energy savings realized through the programs will count toward Arizona’s EE Standards and the associated lost revenue will be partially recovered through the LFCR. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

ENVIRONMENTAL MATTERS

The EPA regulates the amount of SO_2, nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury and other by-products produced 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. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. TEP expects to recover the cost of environmental compliance from its ratepayers.

National Ambient Air Quality Standards

In October 2015, the EPA released the final rule for the 8-hour Ozone NAAQS or Ozone Standard. The EPA lowered the standard from 75 parts per billion (ppb) to 70ppb. If Pima County does not meet the standard, the county will be designated as a “non-attainment” area and will need to develop a plan to bring the air-shed into compliance. A “non-attainment” designation may slow economic growth in the region and impact our ability to site new local generation.

Implementation of the rule is scheduled as follows:

- States’ recommendation of area designations (attainment, non-attainment, or unclassified) by October 2016.
- EPA's response to states’ designation recommendation by June 2017.
- EPA's finalization of area designations by October 2017, based on 2014-2016 air quality data.

Effluent Limitation Guidelines

In September 2015, as part of the Clean Water Act the EPA published the final Effluent Limitation Guidelines setting technology standards and limitations for steam electric power plant discharges. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. TEP is evaluating the effects of this rule on its facilities including Navajo, San Juan, and Four Corners. Since the majority of TEP's facilities are zero discharge, TEP does not anticipate a significant financial impact.

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

EMPLOYEES
At December 31, 2015, TEP had 1,478 employees, of which approximately 688 were represented by the International Brotherhood of Electrical Workers (IBEW) Local No. 1116. A new collective bargaining agreement between the IBEW and TEP was entered into in January 2016 and expires in January 2019.

SEC REPORTS AVAILABLE ON TEP'S WEBSITE
TEP makes available its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practical after we electronically file or furnish them to the Securities and Exchange Commission (SEC). These reports are available free of charge through TEP’s website address at www.tep.com/about/investors/.
UNS Energy’s code of ethics, which applies to the Board of Directors and all officers and employees of UNS Energy and its subsidiaries, including TEP, and any amendments or any waivers made to the code of ethics, is also available on TEP’s website at www.tep.com/about/investors/.
TEP is providing the address of TEP’s website solely for the information of investors and does not intend the address to be an active link. Information contained at TEP’s website is not part of, or incorporated by reference into, any report or other filing filed with the SEC by TEP.

ITEM 1A. RISK FACTORS
The business and financial results of TEP are subject to a number of risks and uncertainties, including those set forth below. These risks and uncertainties fall primarily into five major categories: revenues, regulatory, environmental, financial, and operational.
REVENUES
National and local economic conditions can negatively affect the results of operations, net income, and cash flows at TEP.
Economic conditions have contributed significantly to a reduction in TEP’s retail customer growth and lower energy usage by the company’s residential, commercial, and industrial customers. As a result of weak economic conditions, TEP’s average retail customer base grew by less than 1% in each year from 2011 through 2015 compared with average increases of approximately 1% in each year from 2005 to 2009. TEP estimates that a 1% change in annual retail sales could impact pre-tax net income and pre-tax cash flows by approximately $6 million.
New technological developments and compliance with the ACC's EE Standards and RES will continue to have a significant impact on retail sales, which could negatively impact TEP’s results of operations, net income, and cash flows.
Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-owned generation, and appliances, equipment, and control systems. Continued development and use of these technologies and compliance with the ACC's EE Standards could further impact the results of operations, net income, and cash flows of TEP.
The revenues, results of operations, and cash flows of TEP are seasonal, and are subject to weather conditions and customer usage patterns, which are beyond the company’s control.
TEP typically earns the majority of its operating revenue and net income in the third quarter because retail customers increase their air conditioning usage during the summer. Conversely, TEP’s first quarter net income is typically limited by relatively mild winter weather in its retail service territory. Cool summers or warm winters may reduce customer usage, adversely affecting operating revenues, cash flows, and net income by reducing sales.
TEP is dependent on a small segment of large customers for future revenues. A reduction in the electricity sales to these customers would negatively affect our results of operations, net income, and cash flows.
TEP sells electricity to mines, military installations, and other large industrial customers. In 2015, 35% of TEP’s retail kWh sales were to 592 industrial and mining customers. Retail sales volumes and revenues from these customer classes could

decline as a result of, among other things: global, national, and local economic conditions; curtailments of customer operations due to declines in commodity prices; decisions by the federal government to close military bases; the effects of energy efficiency and distributed generation; or the decision by customers to self-generate all or a portion of their energy needs. A reduction in retail kWh sales to TEP's large customers would negatively affect our results of operations, net income, and cash flows.

REGULATORY

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

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

TEP's Retail Rates consist of Base Rates and various rate adjustors that allow for timely recovery of certain costs between rate cases. The ACC is charged with setting Retail Rates that allow TEP to recover its costs of service and an opportunity to earn a reasonable rate of return. In setting TEP's Retail Rates, the ACC could disallow the recovery of costs or not provide for the timely recovery of costs. The decisions made by the ACC on such matters impact the net income and cash flows of TEP.

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

TEP is subject to the impact of comprehensive and changing governmental regulation at the federal level that continues to change the structure of the electric and gas utility industries and the ways in which these industries are regulated. TEP is subject to regulation by the FERC. The FERC has jurisdiction over rates for electric transmission in interstate commerce and rates for wholesale sales of electric power, including terms and prices of transmission services and sales of electricity at wholesale.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power systems, including TEP, are subject to mandatory transmission standards developed and enforced by NERC and subject to the oversight of the FERC. Compliance with modified or new transmission standards may subject TEP to higher operating costs and increased capital costs. Failure to comply with the mandatory transmission standards could subject TEP to sanctions, including substantial monetary penalties.

ENVIRONMENTAL

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

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

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

Existing environmental laws and regulations may be revised and new environmental laws and regulations may be adopted or become applicable to our facilities. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on our results of operations, particularly if those costs are not fully recoverable from our customers. TEP's obligation to comply with the EPA's Best Available Retrofit Technology (BART) determinations as a participant in the San Juan, Four Corners, and Navajo plants, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to meet their obligations and willingness to continue their participation in these plants. TEP cannot predict the ultimate outcome of these matters.

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

Federal regulations limiting greenhouse gas emissions require a shift in generation from coal to natural gas and renewable generation and could increase TEP's cost of operations.
In August 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil fueled power plants. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan requires CO_2 emission reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. The CPP will require a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal generation in Arizona within the 2022 to 2030 compliance time-frame. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. TEP is unable to determine how the final CPP rule will impact its facilities until the plans are developed and approved by the EPA.
Early closure of TEP's coal-fired generation plants resulting from environmental regulations could result in TEP recognizing impairments in respect of such plants and increased cost of operations if recovery of our remaining investments in such plants and the costs associated with such early closures were not permitted through rates charged to customers.
TEP's coal-fired generating stations may be required to be closed before the end of their useful lives in response to recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If any of the coal-fired generation plants, or coal handling facilities, from which TEP obtains power are closed prior to the end of their useful life, TEP could be required to recognize an impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning, reclamation and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any of such generating stations may force TEP to incur higher costs for replacement capacity and energy. TEP may not be permitted full recovery of these costs in the rates it charges its customers. As of December 31, 2015, approximately 49% of TEP's generating capacity is fueled by coal.
FINANCIAL
The Third-Party Owners of Springerville Unit 1 have and may continue to refuse to pay some, or all, of their pro-rata share of the costs and expenses associated with Springerville Unit 1.
TEP owns 49.5% of Springerville Unit 1 and two separate third-parties own the remaining 50.5%. Starting in January 2015, TEP is obligated to operate Springerville Unit 1 for these Third-Party Owners under existing agreements. TEP and the Third-Party Owners disagree on several key aspects of these agreements, including the allocation of Springerville Unit 1 operating and maintenance expenses, capital improvement costs, and transmission rights. In addition, since late 2014 the Third-Party Owners have filed separate complaints at the FERC, in New York State court, and with the American Arbitration Association that include allegations that TEP violated certain provisions of the governing agreements in relation to TEP’s operation of Springerville Unit 1. Because of these disagreements and the pending litigation, the Third-Party Owners have and may continue to refuse to pay some or all of their pro-rata share of such Springerville Unit 1 costs and expenses. As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016. The Third-Party Owners’ share of estimated 2016 operations and maintenance costs for Springerville Unit 1 is approximately $27 million and their share of estimated 2016 capital expenditures is approximately $9 million.
Volatility or disruptions in the financial markets, or unanticipated financing needs, could: increase our financing costs; limit our access to the credit markets; affect our ability to comply with financial covenants in our debt agreements; and increase our pension funding obligations. Such outcomes may adversely affect our liquidity and our ability to carry out our financial strategy.
We rely on access to the bank markets and capital markets as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. Market disruptions such as those experienced in 2008 and 2009 in the United States and abroad may increase our cost of borrowing or adversely affect our ability to access sources of liquidity needed to finance our operations and satisfy our obligations as they become due. These disruptions may include turmoil in the financial services industry, including substantial uncertainty surrounding particular lending institutions and counterparties we do business with, unprecedented volatility in the markets where

our outstanding securities trade, and general economic downturns in our utility service territories. If we are unable to access credit at competitive rates, or if our borrowing costs dramatically increase, our ability to finance our operations, meet our short-term obligations, and execute our financial strategy could be adversely affected.

Changing market conditions could negatively affect the market value of assets held in our pension and other retiree plans and may increase the amount and accelerate the timing of required future funding contributions.

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

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

As of December 31, 2015, there were outstanding approximately $309 million aggregate principal amount of tax-exempt bonds that financed pollution control facilities at TEP’s generating units. Should certain of TEP’s generating units be retired and dismantled prior to the stated maturity dates of the related tax-exempt bonds, it is possible that some or all of the bonds financing such facilities would be subject to mandatory early redemption by TEP. Of the total amount outstanding, $37 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $272 million principal amount of the bonds have early redemption dates or final maturities ranging from 2019 to 2022.

In addition, as of December 31, 2015, there were outstanding approximately $307 million aggregate principal amount of tax-exempt bonds that financed local furnishing facilities. Depending on changes that may occur to the regional generation mix in the desert southwest, to the regional bulk transmission network, or to the demand for retail energy in TEP’s local service area, it is possible that TEP would no longer qualify as a local furnisher of energy within the meaning of the Internal Revenue Code. In recent years, reductions in retail demand in the winter months have made it increasingly difficult for TEP to continue to qualify as a local furnisher of electricity. If TEP could no longer qualify as a local furnisher of energy, all of TEP’s tax-exempt local furnishing bonds would be subject to mandatory early redemption by TEP or defeasance to the earliest possible redemption date. Of the total tax-exempt local furnishing bonds outstanding, $100 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $207 million principal amount of the bonds have early redemption dates ranging from 2020 to 2023.

TEP’s net income and cash flows can be adversely affected by rising interest rates.

At December 31, 2015, TEP had $137 million of tax-exempt variable rate debt obligations. The interest rates are set weekly or monthly. The average weekly interest rates (including Letters of Credit (LOCs) and remarketing fees) ranged from 0.93% - 1.42% in 2015. The average monthly interest rates ranged from 0.79% - 0.87%. A 100 basis point increase in the average interest rates on this debt over a twelve-month period would increase TEP’s interest expense by approximately $1 million.

TEP is also subject to risk resulting from changes in the interest rate on its borrowings under the 2015 Credit Agreement. Such borrowings may be made on a spread over London Interbank Offer Rate (LIBOR) or an Alternate Base Rate.

If short-term interest rates rise, the resulting increase in the cost of variable rate borrowings would negatively impact our results of operations, net income, and cash flows. Likewise, if capital market conditions result in higher long-term interest rates, TEP’s borrowing costs would increase on any new long-term debt needed to finance capital expenditures or to refinance existing long-term debt.

OPERATIONAL

The operation of electric generating stations, and transmission and distribution systems, involves risks that could result in reduced generating capability or unplanned outages that could adversely affect TEP’s results of operations, net income, and cash flows.

The operation of electric generating stations, and transmission and distribution systems, involves certain risks, including equipment breakdown or failure, fires, weather, and other hazards, interruption of fuel supply, and lower than expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of our business. If TEP’s generating stations and transmission and distribution systems operate below expectations, TEP’s operating results could be adversely affected and/or TEP's capital spending could be increased.

TEP receives power from certain generating facilities that are jointly owned and operated by third parties. Therefore, TEP may not have the ability to affect the management or operations at such facilities which could adversely affect

TEP's results of operations, net income, and cash flows.

Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities. As a result of this reliance on other operators, TEP may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have no ability or a limited ability to make determinations on how best to manage the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed in the face of requirements relating to environmental compliance which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP.

We may be subject to physical attacks.

As operators of critical energy infrastructure, we may face a heightened risk of physical attacks on our electric systems. Our electric generation, transmission, and distribution assets and systems are geographically dispersed and are often in rural or unpopulated areas which make them especially difficult to adequately detect, defend from, and respond to such attacks.

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

We may be subject to cyber attacks.

We may face a heightened risk of cyber attacks. Our information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes. Our operations technology systems have direct control over certain aspects of the electric system and, in addition, our utility business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

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

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

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or liens existing at the time the easements were acquired.

Springerville is located on property held by TEP under a term patent with the State of Arizona. TEP, under separate sale and leaseback arrangements, leases a 50% undivided interest in the Springerville Common Facilities (which do not include land).

Four Corners and Navajo are located on properties held under easements from the United States and under leases from the Navajo Nation. TEP, individually and in conjunction with PNM in connection with San Juan, has acquired land rights, easements and leases for the plant, transmission lines and a water diversion facility located on land owned by the Navajo

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Nation. TEP also has acquired easements for transmission facilities related to San Juan, Four Corners, and Navajo located on reservation lands of the Zuni, Navajo, and Tohono O'odham Nations. TEP, in conjunction with PNM and Samchully Power & Utilities 1 LLC, holds an undivided ownership interest in the property on which Luna is located. TEP's rights under these various easements and leases may be subject to defects such as:

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

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

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

- The Solar Zone of the University of Arizona Tech Park in Pima County, Arizona; and
- Bright Tucson Community Solar Blocks in Pima County, Arizona.

In December 2014, TEP placed in service an additional photovoltaic facility in Cochise County, Arizona, for which TEP entered into a 30-year easement agreement. The easement is to facilitate the operations of a solar photovoltaic renewable energy generation system on behalf of the Department of the Army, located at Fort Huachuca in Cochise County.

See Item 1. Business, General for additional information regarding generating facilities.

ITEM 3. LEGAL PROCEEDINGS

Springerville Unit 1 Proceedings

Upon the termination of the Springerville Unit 1 Leases on January 1, 2015, 50.5% of Springerville Unit 1, or 195 MW of capacity, continued to be owned by third parties, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners). TEP is not obligated to purchase any of the Third-Party Owners' Springerville Unit 1 power.

Commencing on January 1, 2015, with the termination of the leases, TEP is obligated to operate the unit for the Third-Party Owners under existing agreements. In 2014, TEP and the Third-Party Owners engaged in discussions regarding the post-lease operation of Springerville Unit 1 and related cost sharing arrangements, but did not reach agreement on several key points.

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

On December 19, 2014, the Third-Party Owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County (New York Action). In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged, and the court's subsequent ruling on the motions, the Third-Party Owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases and that TEP has breached the lease transaction documents by refusing to pay certain of the Third-Party Owners' claimed expenses. The third amended complaint seeks $71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The Third-Party Owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015, the Third-Party Owners filed a motion for summary judgment on their claim that TEP has failed to pay certain of the Third-Party Owners' claimed expenses.

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

In April 2015, TEP filed a demand for arbitration with the American Arbitration Association (AAA) seeking an award of the Owner Trustees and Co-Trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015, the Third-Party Owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The Third-Party Owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the Third-Party Owners' fees and expenses. TEP and the Third-Party Owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015, the Third-Party Owners filed an amended arbitration demand adding claims that TEP has converted the Third-Party Owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. In October 2015, the arbitration panel granted TEP's motion for interim relief, ordering the Owner Trustees and Co-Trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners' motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling, when economical, the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 14, 2015. The arbitration hearing is scheduled for July 2016.

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

As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1, and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time. TEP intends to vigorously defend itself against the claims asserted by the Third-Party Owners and to vigorously pursue the claims it has asserted against the Owner Trustees and Co-Trustees.

TEP and the Third-Party Owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations for additional information regarding Springerville Unit 1.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Market Information

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

Dividends

TEP paid dividends to UNS Energy of $50 million in 2015 and $40 million in 2014 and 2013.

TEP can pay dividends if it maintains compliance with its 2015 Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement which all contain substantially the same financial covenants. At December 31, 2015, TEP was in compliance with the terms of all financial covenants and agreements.

The ACC's approval of the acquisition of UNS Energy by Fortis, in August 2014, contained a condition restricting subsidiary dividend payments to UNS Energy by TEP to no more than 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital as accounted for in accordance with GAAP. The ratios used to determine the dividend restrictions will be calculated for each calendar year and reported to the ACC annually beginning on April 1, 2016. As of December 31, 2015, TEP's dividend payments were still restricted as the 50 percent of total capital threshold had not yet been reached.

ITEM 6. SELECTED FINANCIAL DATA

(in thousands)	2015	2014	2013	2012	2011
Income Statement Data					
Operating Revenues	$1,306,544	$1,269,901	$1,196,690	$1,161,660	$1,156,386
Net Income	127,794	102,338	101,342	65,470	85,334
Balance Sheet Data					
Total Utility Plant, Net	$3,558,229	$3,425,190	$2,944,455	$2,750,421	$2,650,652
Total Assets (1)	4,249,478	4,119,830	3,490,085	3,413,638	3,247,647
Long-Term Debt, Net (1)	$1,451,720	$1,361,828	$1,213,367	$1,213,246	$1,072,037
Non-Current Capital Lease Obligations	55,324	69,438	131,370	262,138	352,720
Cash Flow Data					
Net Cash Flows From Operating Activities	$364,934	$313,663	$346,191	$267,919	$268,294
Net Cash Flows From Investing Activities	(502,891)	(517,638)	(259,662)	(227,881)	(312,011)
Net Cash Flows From Financing Activities	119,471	252,810	(140,937)	11,987	51,452
Other Data					
Ratio of Earnings to Fixed Charges (2)	3.74	2.56	2.67	2.10	2.40

(1) Total Assets and Long-term Debt, Net were adjusted to reflect the reclassifications made as a result of the recently adopted accounting pronouncements. See Note 1 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding recently adopted accounting pronouncements.

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

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

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

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

- outlook and strategies;
- operating results during 2015 compared with the same periods of 2014, and 2014 compared with 2013;
- factors affecting our results and outlook;
- liquidity, capital needs, capital resources, and contractual obligations;
- dividends; and
- critical accounting estimates.

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

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

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

OUTLOOK AND STRATEGIES

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

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

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2015 Operational and Financial Highlights

The year ended December 31, 2015 included the following notable items:

- In January 2015, TEP purchased an additional 24.8% undivided ownership interest in Springerville Unit 1, bringing its total ownership interest to 49.5%;
- In January 2015, TEP purchased existing unsecured tax-exempt industrial development revenue bonds in the amount of $130 million using funds borrowed from the term loan portion of the 2014 Credit Agreement;
- In February 2015, TEP issued and sold $300 million of unsecured notes;
- In April 2015, TEP purchased an additional 86.7% undivided ownership interest in the Springerville Coal Handling Facilities, and in May 2015, TEP sold a 17.05% undivided ownership interest in the Springerville Coal Handling Facilities to SRP;
- In June 2015, TEP terminated the 2014 Credit Agreement;
- In June 2015, TEP received an equity contribution of $180 million from UNS Energy;
- In October 2015, TEP entered into a new unsecured credit agreement (2015 Credit Agreement) that provides for a $250 million revolving credit and letter of credit (LOC) facility. The new credit agreement matures in 2020 and replaces the 2010 Credit Agreement;
- In November 2015, TEP filed a general rate case with the ACC that requests, among other things, a Base Rate increase of $110 million. The application also requests that new rates become effective no later than January 1, 2017; and
- In December 2015, TEP completed construction and placed into service a 500-kV transmission line extending from the Pinal Central substation to TEP’s Tortolita substation northwest of Tucson.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations for the years ended December 31, 2015, 2014 and 2013. The significant items affecting net income are presented on an after-tax basis.

2015 compared with 2014

TEP reported net income of $128 million in 2015 compared with $102 million in 2014. The increase of $26 million, or 25%, was primarily due to:

- $16 million in lower O&M resulting primarily from acquisition related costs and outages at Springerville Units 1 and 2 that were incurred in 2014, partially offset by higher O&M related to Gila River, labor costs, and outside services;
- $6 million in higher transmission revenue resulting primarily from an increase in sales volume on favorably priced contracts; and
- $4 million in lower interest expense primarily due to a reduction in the balance of capital lease obligations.

2014 compared with 2013

TEP reported net income of $102 million in 2014 compared with $101 million in 2013. The increase of $1 million, or 1%, was primarily due to:

- $25 million in higher revenues including a non-fuel Base Rate increase that was effective on July 1, 2013, an increase in LFCR revenues, higher long-term wholesale revenues due in part to an increase in the average market price and higher transmission revenue; and
- $7 million in lower interest expense, primarily due to a reduction in the balance of capital lease obligations.

The increase was partially offset by:

- $22 million in higher O&M for acquisition related costs, higher generating plant maintenance expense, and increased rent expense associated with the Navajo lease amendment;

- $5 million in higher income taxes primarily generated by a non-recurring $11 million tax benefit recorded in June 2013 to recover previously recorded income tax expense as a result of the 2013 TEP Rate Order. This amount is partially offset by a $2 million increase in the valuation allowance in 2013 and a $3 million increase in investment tax credits recorded in 2014. See Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes; and
- $4 million in higher depreciation and amortization expenses, resulting primarily from an increase in asset base in the current year.

Utility Sales and Revenues

The table below provides a summary of retail kWh sales, revenues, and weather data during 2015, 2014 and 2013:

	Year Ended		Increase (Decrease)		Year Ended	Increase (Decrease)	
	2015	2014	Percent[1]		2013	Percent[1]	
Electric Retail Sales (kWh in millions)							
Residential	3,724	3,727	(0.1	)%	3,867	(3.6	)%
Commercial	2,124	2,170	(2.1	)%	2,187	(0.8	)%
Industrial	2,063	2,098	(1.7	)%	2,114	(0.8	)%
Mining	1,109	1,137	(2.5	)%	1,079	5.4	%
Public Authorities	33	33	—	%	32	3.1	%
Total Electric Retail Sales	9,053	9,165	(1.2	)%	9,279	(1.2	)%
Retail Margin Revenues (in millions)							
Residential	$281	$280	0.4	%	$271	3.3	%
Commercial	185	188	(1.6	)%	181	3.9	%
Industrial	103	104	(1.0	)%	97	7.2	%
Mining	38	38	—	%	34	11.8	%
Public Authorities	2	2	—	%	2	—	%
Total by Customer Class	609	612	(0.5	)%	585	4.6	%
LFCR Revenues	12	11	9.1	%	2	*	
DSM Performance Bonus	3	2	50.0	%	1	100.0	%
Other Retail Margin Revenues	5	1	*		—	*	
Total Retail Margin Revenues (Non-GAAP) [1]	629	626	0.5	%	588	6.5	%
Fuel and Purchased Power Revenues	344	303	13.5	%	300	1.0	%
DSM and RES Surcharge Revenues	49	41	19.5	%	46	(10.9	)%
Total Retail Revenues (GAAP)	$1,022	$970	5.4	%	$934	3.9	%
Average Retail Margin Rate (Cents / kWh) [2]							
Residential	7.55	7.51	0.5	%	7.02	7.0	%
Commercial	8.71	8.66	0.6	%	8.28	4.6	%
Industrial	4.99	4.96	0.6	%	4.61	7.6	%
Mining	3.43	3.34	2.7	%	3.14	6.4	%
Public Authorities	5.61	6.06	(7.4	)%	5.56	9.0	%
Total Average Margin Rate by Customer Class	6.73	6.68	0.7	%	6.30	6.0	%
Total Average Retail Margin Rate [3]	6.95	6.80	2.2	%	6.31	7.8	%
Average Fuel and Purchased Power Rate	3.80	3.31	14.8	%	3.24	2.2	%
Average DSM and RES Rate	0.54	0.48	12.5	%	0.52	(7.7	)%
Total Average Retail Rate	11.29	10.59	6.6	%	10.07	5.2	%
Weather Data							
Cooling Degree Days							
Year Ended December 31,	1,576	1,557	1.2	%	1,631	(4.5	)%
10-Year Average	1,520	1,515	*		1,491	*	
Heating Degree Days							
Year Ended December 31,	1,072	930	15.3	%	1,449	(35.8	)%
10-Year Average	1,317	1,335	*		1,404	*	

* Not meaningful

(1) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude: (i) revenues collected

from retail customers that are

directly offset by expenses recorded in other line items; and (ii) revenues collected from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues from kWh sales, LFCR Revenues, DSM Performance Bonus, and certain other retail margin revenues available to cover the non-fuel operating expenses of our core utility business.

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

(3) Total Average Retail Margins Rates include revenues related to LFCR Revenues, DSM Performance Bonus, and Other Retail Margin Revenues included in the Total Retail Margin Revenues.

Retail Revenues were higher in 2015 compared with 2014 primarily due to the increase in the PPFAC rate and higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to higher LFCR revenues, DSM Performance Bonus, and Other Retail Margin Revenues related to adjustor mechanisms.

Retail Revenues were higher in 2014 compared with 2013 primarily due to higher Retail Margin Revenues and increased LFCR revenues. The increase in Retail Margin Revenues resulted from a non-fuel Base Rate increase effective July 1, 2013. These increases were partially offset by lower sales volume due to milder weather.

Wholesale Sales and Transmission Revenues

	Year Ended December 31,		
(in millions)	2015	2014	2013
Long-Term Wholesale Revenues	$36	$28	$26
Transmission Revenues	27	16	15
Short-Term Wholesale Revenues	104	114	92
Total Electric Wholesale Sales	$167	$158	$133

Long-Term Wholesale Revenues increased by $8 million, or 29%, in 2015 compared with 2014 primarily due to new wholesale agreements partially offset by unfavorable wholesale market prices. Transmission Revenues increased by $11 million, or 69%, in 2015 compared with 2014 primarily due to a new long-term transmission agreement with UNS Electric related to Gila River and contract renewals resulting in favorable pricing.

Long-Term Wholesale Revenues increased by $2 million, or 8%, in 2014 compared with 2013 primarily due to favorable market prices for wholesale power. There were no significant changes in transmission revenues in 2014 compared to 2013.

The majority of revenues from short-term wholesale sales are related to ACC jurisdictional assets and are credited against the fuel and purchased power costs eligible for recovery in the PPFAC.

Other Revenues

	Year Ended December 31,		
(in millions)	2015	2014	2013
Springerville Units 3 and 4 Revenue (1)	$91	$112	$102
Other Revenue	27	29	28
Total Other Revenue	$118	$141	$130

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

In addition to reimbursements related to Springerville Units 3 and 4, TEP's other revenues include inter-company revenues from its affiliates, UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy, (UNS Gas) and UNS Electric, for corporate services provided by TEP, and miscellaneous service-related revenues such as rent on power pole attachments, damage claims, and customer late fees. See Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding related party transactions.

There were no significant changes in Other Revenue in 2015 compared with 2014, as well as no significant changes in Other Revenue in 2014 compared with 2013.

Operating Expenses

Generating Output and Fuel and Purchased Power Expense

TEP's fuel and purchased power expense and energy resources for 2015, 2014, and 2013 are detailed below:

	Generation and Purchased Power (kWh)			Fuel and Purchased Power Expense		
(in millions)	2015	2014	2013	2015	2014	2013
Coal-Fired Generation	8,584	9,271	10,254	$209	$232	$273
Gas-Fired Generation	2,723	1,210	1,007	91	60	46
Utility Owned Renewable Generation	65	48	38	—	—	—
Reimbursed Fuel Expense for Springerville Units 3 and 4 (1)	—	—	—	5	5	7
Total Generation	11,372	10,529	11,299	305	297	326
Total Purchased Power	3,079	3,195	2,329	125	153	112
Transmission and Other PPFAC Recoverable Costs	—	—	—	25	18	12
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	—	40	(11)	(12)
Total Generation and Purchased Power	14,451	13,724	13,628	$495	$457	$438
Less Line Losses and Company Use	(719)	(859)	(885)			
Total Energy Sold	13,732	12,865	12,743			

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

Fuel and Purchased Power Expense increased by $38 million, or 8%, in 2015 compared with 2014 primarily due to an increase in the PPFAC charge and additional generation and transmission costs associated with Gila River Unit 3. The increase was partially offset by favorable purchased power costs (see table below) and decreased coal generation at Springerville Unit 1 as a result of the lease expiration in January 2015.

Fuel and Purchased Power Expense increased by $19 million, or 4%, in 2014 compared with 2013 primarily due to the increase in purchased power volumes resulting from outages at Springerville and Sundt generating stations in 2014. The increase was partially offset by a decrease in generation expense as a result of the outages.

See the table below for information on the average fuel cost of generated and purchased kWh:

(cents per kWh)	2015	2014	2013
Coal	2.44	2.50	2.66
Gas	3.35	4.99	4.57
Purchased Power	4.05	4.79	4.83
All Sources	3.31	3.64	3.54

Operations and Maintenance Expense

The table below summarizes the items included in Operations and Maintenance (O&M) expense:

(in millions)	2015	2014	2013
Reimbursed Expenses - Springerville Units 3 and 4 (1)	$65	$84	$70
Reimbursed Expenses - Customer Funded Renewable Energy and DSM Programs (2)	25	23	26
Other Operating and Maintenance Expense (3)	255	272	239
Total Operations and Maintenance Expense	$345	$379	$335

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

(2) These expenses are being collected from customers and the corresponding amounts are recorded in retail revenue.

(3) The Third-Party Owners' share of expenses related to Springerville Unit 1 is included in Other Operating and Maintenance Expense.

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Operating and Maintenance expenses decreased by $34 million, or 9%, in 2015 compared with 2014. Springerville Units 3 and 4 expenses, which are reimbursed by third party owners, decreased primarily due to outages incurred in 2014. Other Operating and Maintenance Expense decreased primarily due to acquisition related costs and outages at Springerville Units 1 and 2 that occurred in 2014, partially offset by higher O&M related to Gila River, labor costs and outside services.

Operating and Maintenance expenses increased by $44 million, or 13%, in 2014 compared with 2013. Springerville Units 3 and 4 expenses, which are reimbursed by third party owners, increased primarily due to outages incurred in 2014. Other Operating and Maintenance Expense increased primarily due to acquisition related costs and outages at Springerville Units 1 and 2 that occurred in 2014.

FACTORS AFFECTING RESULTS OF OPERATIONS

2015 Rate Case

In November 2015, TEP filed a general rate case with the ACC to: (i) update and improve its rate design and tariffs to provide more accurate price signals and a more equitable allocation of its fixed costs to its customers; (ii) provide TEP with an opportunity to recover its full cost of service, including an appropriate return on its rate base investments; and (iii) enable TEP to continue to provide safe and reliable service. The rate application is based on a test year ended June 30, 2015. The filing requests that new rates be implemented by January 1, 2017.

The key provisions of the rate case include:

- a Base Rate increase of $110 million, or 12%, compared with adjusted test year revenues;
- a 7.34% return on original cost rate base of $2.1 billion;
- a capital structure for rate making purposes of approximately 50% common equity and 50% long-term debt;
- a cost of equity of 10.35% and an average cost of debt of 4.32%;
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of San Juan Unit 2 and the Sundt Coal Handling Facilities due to early retirement;
- a request for authority to begin using the Third-Party Owners' portion of Springerville Unit 1 that is available to TEP for dispatch to serve retail customer needs and to recover the related operating costs through the PPFAC; and
- rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service.

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

Generating Resources

At December 31, 2015, approximately 49% of TEP's generating capacity was fueled by coal. Existing and proposed federal environmental regulations, as well as potential changes in state regulation, may increase the cost of operating coal-fired generating facilities. TEP is executing strategies and evaluating additional steps to reduce its dependency on coal generation.

In August 2015, TEP exhausted its existing coal supply at Unit 4 of the H. Wilson Sundt Generating Station (Sundt Unit 4). Currently, TEP is operating Sundt Unit 4 on natural gas as a primary fuel source.

TEP's ability to further reduce its coal-fired generating capacity will depend on several factors, including, but not limited to:

- The impact of the Clean Power Plan on current coal-fired generating facilities; and
- The ability to resolve Springerville Unit 1 legal proceedings relating to the Third-Party Owners.

See Part I, Item 1. Business, General for additional information regarding TEP's generating facilities.

Springerville Unit 1

TEP leased Unit 1 of the Springerville Generating Station and an undivided one-half interest in certain Springerville Common Facilities (collectively Springerville Unit 1) under seven separate lease agreements (Springerville Unit 1 Leases) that were accounted for as capital leases. The leases expired in January 2015. At that time, TEP purchased a leased interest comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million. Following this purchase, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. The remaining 50.5% of Springerville Unit 1, or 195 MW of capacity, is owned by Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners). TEP is not obligated to purchase any of the Third-Party Owners' generating output. TEP is obligated to operate the unit for the Third-Party Owners. Owner Trustees and Co-Trustees are obligated to compensate TEP for their pro rata share of expenses for the unit. TEP estimates the Third-Party Owners' share of 2016 operations and maintenance expense will be $27 million and their estimated share of 2016 capital expenditures will be $9 million.

In April 2015, TEP filed a demand for arbitration seeking an award of the Owner Trustees and Co-Trustees' share of unreimbursed expense and capital expenditures for Springerville Unit 1. In October 2015, the arbitration panel granted TEP's motion for interim relief, ordering the Owner Trustees and Co-Trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners' motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling, when economical, the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 14, 2015. As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and Part I, Item 3. Legal Proceedings for additional information regarding the legal proceedings relating to the Third-Party Owners.

Potential Plant Retirements

TEP's 2014 Integrated Resource Plan (IRP), which was acknowledged by the ACC in April 2015, reflected plans to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) by 2018. TEP's 2014 IRP included retiring certain coal-fired generating facilities at San Juan Generating Station (San Juan) and coal handling facilities at the H. Wilson Sundt Generating Station (Sundt) earlier than their current estimated useful lives. These facilities currently do not have the requisite emission control equipment to meet proposed Environmental Protection Agency (EPA) regulations. TEP plans to seek regulatory recovery for amounts that would not otherwise be recovered if and when any assets are retired. TEP plans to file a preliminary IRP in March 2016 and is required to file its next IRP by April 2017.

See Part I, Item 1. Business, Environmental Matters for additional information regarding the impact of environmental matters on plant operations.

Springerville Coal Handling Facilities Capital Lease Purchase

TEP previously leased interests in the coal handling facilities at the Springerville Generating Station (Springerville Coal Handling Facilities) under two separate lease agreements (Springerville Coal Handling Facilities Leases). The lease agreements had an initial term that expired in April 2015 and provided TEP the option to renew the leases or to purchase the leased interests at the aggregate fixed price of $120 million. In April 2015, TEP exercised its option to purchase the facilities.

Upon the expiration of the lease term, TEP purchased an 86.7% undivided ownership interest in the Springerville Coal Handling Facilities bringing TEP's total ownership interest to 100%. With the completion of the purchase, SRP was obligated to buy a 17.05% undivided interest in the Springerville Coal Handling Facilities from TEP for approximately $24 million. This transaction was completed in May 2015. Tri-State, is obligated to either: 1) buy a 17.05% undivided interest in the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. Tri-State has until April 2016 to exercise its purchase option.

Sales to Mining Customers

TEP's largest mining customer is taking initial steps to curtail production in 2016 due to the decline in commodity prices. TEP cannot predict the extent to which this customer will curtail production, how long commodity prices will remain low, or the

total impact the prices will have on mining production in the future. At December 31, 2015, mining customers made up 8% of TEP's total electric sales.
The proposed Rosemont Copper Mine near Tucson, Arizona is in the permitting stage. If the Rosemont Copper Mine is constructed and reaches full production, it will become TEP's largest retail customer with an estimated load of approximately 85 to 120 MW.

Interest Rates

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

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

Cash flows may vary during the year, with cash flows from operations typically the lowest in the first quarter and highest in the third quarter due to TEP’s summer peaking load. As a result of the varied seasonal cash flow, we will use, as needed, our revolving credit facility to assist in funding business activities. We believe that we have sufficient liquidity under our revolving credit facilities to meet short-term working capital needs and to provide credit enhancement as necessary under energy procurement and hedging agreements.

Available Liquidity

(in millions)	As of December 31, 2015
Cash and Cash Equivalents	$56
Amount Available under Revolving Credit Facility [(1)]	250
Total Liquidity	$306

(1) TEP's revolving credit facility, which matures in 2020, provides for a $250 million revolving credit commitment with a LOC sublimit of $50 million.

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

Summary of Cash Flow

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

	Year Ended		Increase (Decrease)	Year Ended	Increase (Decrease)
(in millions)	2015	2014	Percent	2013	Percent
Operating Activities	$365	$314	16.2 %	$346	(9.2)%
Investing Activities	(503)	(518)	(2.9)%	(260)	99.2 %
Financing Activities	120	253	(52.6)%	(141)	279.4 %
Net Increase (Decrease) in Cash	(18)	49	(136.7)%	(55)	189.1 %
Cash, Beginning of Year	74	25	196.0 %	80	(68.8)%
Cash, End of Year	$56	$74	(24.3)%	$25	196.0 %

Cash Flows for both 2015 and 2014 included unusually large capital expenditures. These capital requirements were met with a combination of equity contributions from UNS Energy and long-term borrowings as discussed in Financing Activities below.

In 2015, we issued long-term debt and used the proceeds to repay revolving and term loans under our credit agreements and pay a portion of the purchase price for interests in the Springerville Coal Handling Facilities. In addition, we received an equity contribution from UNS Energy and used the proceeds to repay the outstanding balances under our revolving credit facilities and redeem long-term variable rate tax-exempt bonds which were called for redemption in June 2015.

In 2014, we received an equity contribution from UNS Energy and used the proceeds to pay for the purchase of both Gila River Unit 3 and Springerville Unit 1 leased assets.

Operating Activities

2015 compared with 2014

In 2015, net cash flows from operating activities increased by $51 million compared to 2014 primarily due to:

- $39 million of higher cash receipts from retail and wholesale sales, net of fuel and purchased power costs paid driven primarily by an increase in the average PPFAC rate; and
- $34 million in lower cash paid for acquisition-related costs and incentive compensation primarily due to the 2014 acquisition.

The increase in net cash flows from operating activities was partially offset by $16 million of higher cash paid for pension and retiree funding.

2014 compared with 2013

In 2014, net cash flows from operating activities decreased by $32 million compared to 2013 primarily due to:

- $27 million of higher cash paid for acquisition-related costs and incentive compensation primarily due to the 2014 acquisition; and
- $6 million of higher cash paid for capital lease interest.

Investing Activities

2015 compared with 2014

In 2015, net cash flows used for investing activities decreased by $15 million compared with 2014 primarily due to:

- $164 million purchase, in December 2014, of a 75% interest in Gila River Unit 3; and
- $20 million purchase, in December 2014, of a 10.6% interest in Springerville Unit 1.

The decrease in net cash flows used for investing activities was partially offset by:

- $120 million purchase, in April 2015, of an additional 86.7% undivided ownership interest in the Springerville Coal Handling Facilities partially offset by $24 million of cash received for the sale, in May 2015, of a 17.05% undivided ownership interest in the Springerville Coal Handling Facilities to SRP;
- $46 million purchase, in January 2015, of an additional 24.8% undivided ownership interest in Springerville Unit 1 increasing our total ownership interest to 49.5%;
- $11 million in lower cash receipts for contributions in aid of construction received; and
- $10 million of higher capital expenditures to fund system reinforcement through replacements and betterments.

2014 compared with 2013

In 2014, net cash flows used for investing activities increased by $258 million compared with 2013 primarily due to:

- $164 million purchase, in December 2014, of a 75% interest in Gila River Unit 3;
- $71 million of higher capital expenditures to fund the construction of new solar projects and improvements to our generating facilities; and
- $20 million purchase, in December 2014, of a 10.6% interest in Springerville Unit 1.

Financing Activities

2015 compared with 2014

In 2015, net cash flows from financing activities decreased by $133 million compared with 2014 primarily due to:

- $209 million in higher cash payments due to the purchase of $130 million in fixed rate tax-exempt long-term debt in January 2015, and the retirement of $79 million in variable rate tax-exempt bonds in August 2015;
- $170 million in lower proceeds borrowed and higher repayments under TEP's revolving credit facilities;
- $45 million in lower cash proceeds from UNS Energy's equity contributions; and
- $10 million in higher cash dividend payments.

The decrease in net cash flows from financing activities was partially offset by:

- $152 million in lower cash payments due to the expiration of capital lease obligations in 2015; and
- $150 million in higher cash proceeds from the issuance of long-term debt, in February 2015.

2014 compared with 2013

In 2014, net cash flows from financing activities increased by $394 million compared with 2013 primarily due to:

- $225 million in higher cash proceeds from UNS Energy's equity contributions made to complete the purchases for interest in Gila River Unit 3 and Springerville Unit 1;
- $149 million in higher cash proceeds from the issuance of long-term debt; and
- $85 million in higher cash borrowings (net of repayments) under TEP's revolving credit facilities.

The increase in net cash flows from financing activities was partially offset by $66 million in higher cash payments of capital lease obligations.

External Sources of Liquidity

Short-Term Investments

TEP's short-term investment policy governs the investment of excess cash balances. We regularly review and update this policy in response to market conditions. At December 31, 2015, TEP's short-term investments included highly-rated and liquid money market funds.

Access to Revolving Credit Facilities

We have access to working capital through a revolving credit agreement with lenders. The 2015 Credit Agreement provides for a $250 million revolving credit commitment and LOC facility, due in October 2020. The LOC sublimit is $50 million. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. No amounts were drawn under the 2015 Credit Agreement at December 31, 2015.

In June 2015, the 2014 Credit Agreement was terminated. In October 2015, the 2010 Credit Agreement was terminated.

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

Debt Financing

We use debt financing to 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 April 2015, we filed a financing application with the ACC. The application requests extending and expanding the existing financing authority to TEP 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) extending current interest rate hedging authority. The ACC issued an order granting such authority in January 2016.

As discussed in Part I, Item 1A. Risk Factors of this Form 10-K, we may need to redeem or defease certain tax-exempt bonds outstanding. To the extent that is required, we would need to issue new taxable debt or enter into a new bank financing.

We have no new financing planned for 2016. TEP has, from time to time, refinanced or repurchased portions of its outstanding debt before scheduled maturity. Depending on market conditions, TEP may refinance other debt issuances or make additional debt repurchases in the future. For details on changes to or maturities on long-term debt, see Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Debt Restrictive Covenants

The 2015 Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement contain pricing based on TEP’s credit ratings. A change in TEP’s credit ratings can cause an increase or decrease in the amount of interest TEP pays on its borrowings, and the amount of fees it pays for its LOCs and unused commitments. Also, under certain agreements, should TEP fail to maintain compliance with covenants, lenders could accelerate the maturity of all amounts outstanding. At December 31, 2015, TEP was in compliance with these covenants.

TEP conducts its wholesale marketing and risk management activities under certain master agreements whereby TEP may be required to post credit enhancements in the form of cash or a LOC due to exposures exceeding unsecured credit limits provided to TEP, changes in contract values, a change in TEP’s credit ratings, or if there has been a material change in TEP’s creditworthiness. As of December 31, 2015, TEP had posted less than $1 million in LOCs for credit enhancement with wholesale counterparties.

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.

Credit Ratings

Our credit ratings affect our access to capital markets and supplemental bank financing. At December 31, 2015, TEP’s credit ratings for senior unsecured debt were A3 from Moody’s and BBB+ from both Standard & Poor’s and Fitch. As of February 2016, at TEP's request for commercial reasons, Fitch withdrew its rating on TEP.

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

Dividends

TEP declared and paid $50 million in dividends to UNS Energy in 2015 and $40 million in 2014 and 2013.

The ACC's approval of the acquisition of UNS Energy by Fortis, in August 2014, contained a condition restricting subsidiary dividend payments to UNS Energy by TEP to no more than 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital as accounted for in accordance with GAAP. The ratios used to determine the dividend restrictions will be calculated for each calendar year and reported to the ACC annually beginning on April 1, 2016. As of December 31, 2015, TEP had not yet reached the 50 percent of total capital and was therefore still restricted by the condition contained in the ACC's approval order.

Capital Expenditures

TEP's routine capital expenditures include funds used for system reinforcement, replacements and betterments, and costs to comply with environmental rules and regulations. In 2015, total capital expenditures of $500 million, included the purchase of an undivided ownership interest in Springerville Unit 1 and the remaining ownership interest in the Springerville Coal Handling facilities. In 2014, total capital expenditures of $507 million, included the purchase of interest in Gila River Unit 3 and an undivided ownership interest in Springerville Unit 1. Construction for a new 500-kilovolt (kV) transmission line in Pinal County that began in December 2014 and concluded in late 2015, totaled $79 million.

With the exception of 2017, we expect capital requirements to remain stable from 2016 through 2020. TEP's forecasted capital expenditures are summarized below:

(in millions)	2016	2017	2018	2019	2020
Generation Facilities:					
Environmental Compliance	$39	$27	$11	$2	$2
Renewable Energy	27	27	27	27	27
Springerville Common Lease Purchase	—	38	—	—	—
Other Generation Facilities	34	82	31	36	39
Total Generation Facilities	100	174	69	65	68
Transmission and Distribution	122	112	159	154	163
General and Other (1)	52	46	56	57	54
Total Capital Expenditures	$274	$332	$284	$276	$285

(1) General and Other primarily includes cost for information technology as well as fleet, facilities and communication equipment.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors. We expect to pay for forecasted capital expenditures with cash on hand, internally generated funds, and short-term revolver borrowings.

Contractual Obligations

The following chart displays TEP’s contractual obligations by maturity and by type of obligation as of December 31, 2015:

		Payments Due by Period			
(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-Term Debt					
Principal (1)	$1,466	$—	$100	$117	$1,249
Interest (2)	769	59	120	116	474
Capital Lease Obligations (3)	77	17	30	30	—
Operating Leases: (4)					
Land Easements and Rights-of-Way	82	1	2	2	77
Operating Leases Other	9	1	2	2	4
Purchase Obligations:					
Fuel, Including Transportation (5)(6)	580	78	125	90	287
Purchased Power	28	28	—	—	—
Transmission	38	6	12	7	13
Renewable Purchase Power Agreements (7)(8)	1,054	61	122	121	750
RES Performance-Based Incentives (9)	107	8	16	16	67
Acquisition of Springerville Common Facilities (10)	106	—	38	—	68
Other Long-Term Liabilities: (11) (12)					
Restricted and Performance-Based Stock Units	2	—	2	—	—
Pension & Other Post Retirement Obligations (13)	77	16	11	13	37
Total Contractual Obligations	$4,395	$275	$580	$514	$3,026

(1) $37 million of TEP’s variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019. Although the variable rate bond matures in 2032, the above table reflects a redemption or repurchase of such bond in 2019 as though the LOC terminates without replacement upon expiration of the 2010 Reimbursement Agreement. TEP's 2013 tax-exempt variable rate IDRBs, which have an aggregate principal amount of $100 million and mature in 2032, are subject to mandatory tender for purchase in 2018. Total long-term debt is not reduced by $11 million of related unamortized debt issuance costs or $3 million of unamortized original issue discount.

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

(3) Effective with commercial operation of Springerville Unit 3 in July 2006 and Unit 4 in December 2009, Tri-State and SRP began reimbursing TEP for various operating costs related to the common facilities on an ongoing basis. The common facilities included assets leased by TEP under the Springerville Common and Springerville Coal Handling Facilities Leases. Upon expiration of the Springerville Coal Handling Lease in April 2015, TEP purchased the interests in those assets. SRP then purchased an undivided interest in those coal handling assets from TEP. Tri-State and SRP each continue to reimburse TEP for their shares of common assets owned or leased by TEP. TEP was reimbursed for $11 million of operation costs in 2015, and absent a purchase of an interest in the coal handling facilities by Tri-State, will be reimbursed $10 million of operation costs in 2016. Capital Lease Obligations do not reflect any reduction associated with this reimbursement. Our capital lease obligation balances decline over time as scheduled capital lease payments are made by TEP.

(4) TEP's operating lease expense is primarily for rail cars, office facilities, land easements, and rights-of-way with varying terms, provisions, and expiration dates.

(5) Contemporaneously with the sale of SJCC's stock in January 2016, the existing coal sale agreement terminated and a new Coal Supply Agreement (CSA) became effective. The new CSA is between SJCC and PNM and continues through June 30, 2022. TEP is not a party to the new CSA, but has minimum purchase obligations under restructured ownership agreements at San Juan. Estimated future payments, not included in the table above, are $21 million in 2016, $23 million in 2017, $24 million in 2018 and 2019, $23 million in 2020, and $22 million through the end of the contract.

(6) Excludes TEP’s liability for final environmental reclamation at the coal mines which supply the Navajo, San Juan and Four Corners generating stations as the timing of payment has not been determined. See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding TEP’s share of reclamation costs.

(7) TEP enters into long-term renewable power purchase agreements which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries.

(8) In February 2016, a facility achieved commercial operation status. The related contract expires in 2036. Estimated future payments, not included in the table above, are $3 million in each of 2016 through 2020 and $43 million through the end of the contract.

(9) TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance-Based Incentives (PBIs) and are paid in contractually agreed upon intervals (usually quarterly) based on metered renewable energy production. PBIs are recoverable through the RES tariff. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding TEP's RES tariff.

(10) The Springerville Common Facilities Leases have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025. Instead of extending the leases, TEP may exercise its fixed-price purchase options.

(11) Excludes asset retirement obligations of $33 million expected to occur through 2066.

(12) Excludes unrecognized tax benefits of $5 million. At this time we are unable to make a reasonably reliable estimate of the timing of payments in individual years in connection with these tax liabilities.

(13) These obligations represent TEP’s expected contributions to pension plans in 2016, expected benefit payments for its unfunded Supplemental Executive Retirement Plan (SERP), and expected retiree benefit costs to cover medical and life insurance claims as determined by the plans’ actuaries. Due to the significant impact that returns on plan assets and changes in discount rates might have on payment obligation amounts, other contributions are excluded beyond 2016.

We expect to pay for forecasted capital expenditures with cash on hand, internally generated funds, and short-term revolver borrowings.

Off Balance Sheet Arrangements

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

Income Tax Position

Prior year tax legislation and the Consolidated Appropriations Act of 2016, include provisions that make qualified property placed in service between 2010 and 2019 eligible for bonus depreciation for tax purposes. In addition, the IRS issued new guidance related to the treatment of expenditures to maintain, replace, or improve property. These provisions are an acceleration of tax benefits TEP otherwise would have received over 20 years and have created net operating loss carryforwards that can be used to offset future taxable income. As a result, TEP did not pay any federal or state income taxes in 2015 and does not expect to make any payments until 2020.

Environmental Matters

The EPA regulates the amount of sulfur dioxide (SO_2), nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury and other by-products produced by 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. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. Complying with these changes may reduce operating efficiency. TEP capitalized $33 million in 2015, $11 million in 2014, and $5 million in 2013 in costs to comply with environmental rules and regulations. In addition, we recorded O&M expenses of $6 million in 2015, $5 million in 2014, and $8 million in 2013. 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 Standards (MATS) rules, additional emission control equipment would have been required by April 2015. TEP, as operator of the Springerville and Sundt generating stations, and the operators of Navajo and Four Corners received extensions until April 2016 to comply with the MATS rules.

In June 2015, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals decision in Michigan v. EPA to uphold the MATS rules requiring power plants to control mercury and other emissions. The Supreme Court held that the EPA did not adequately consider “cost” before determining that MATS was “appropriate and necessary.” The D.C. Circuit Court of Appeals remanded the rules to the EPA for further consideration.

At this time, despite the U.S. Supreme Court ruling, the MATS rules remain in force and effect. TEP will proceed with its planned MATS compliance activity at each of our facilities. Additionally, Arizona has an Arizona-specific mercury rule in place that will become effective and applicable to our Arizona facilities in the event the Federal rule is struck down. Our compliance strategy is intended to ensure compliance with both the Federal and the State rule, as applicable.

TEP's share of the estimated mercury emission control costs to comply with the MATS rules includes the following:

(in millions)	Navajo	Springerville[(1)]
Capital Expenditures	$1	$5
Annual O&M Expenses	$1	$1
Compliance Year	2016	2016

(1) Total capital expenditures and annual O&M expenses represent amounts for Springerville Units 1 and 2, with estimated costs split equally between the two units. In January 2015, TEP completed the purchase of 24.8% of Springerville Unit 1, bringing its total ownership interest to 49.5%. With the completion of the purchase, the Third-Party Owners are 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 no additional capital expenditures or O&M expenses will be incurred to comply with the MATS rules at Four Corners, Sundt, and San Juan Generating Stations.

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as 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 power plants.

In the western U.S., Regional Haze BART determinations have focused on controls for NO_x, often resulting in a requirement to install Selective Catalytic Reduction (SCR). Complying with the BART rule, 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. The BART provisions do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s, after the time frame as designated by the rules. Other provisions of the

Regional Haze Rules requiring further emission reductions are not likely to impact Springerville operations until after 2018. TEP cannot predict the ultimate outcome of these matters.

TEP's estimated NO_x emissions control costs involved in meeting these rules are:

(in millions)	Navajo	San Juan	Four Corners	Sundt
Capital Expenditures	$28	$12	$44	$12
Annual O&M Expenses	$1	$1	$2	$6
Compliance Year	2030	2016	2018	2017

Navajo

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

San Juan

In October 2014, the EPA published a final rule approving a revised State Implementation Plan (SIP) covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017 and the installation of Selective Non-Catalytic Reduction (SNCR) on Units 1 and 4 by February 2016. TEP owns 50% of Units 1 and 2 at San Juan. The SIP approval references a New Source Review permit issued by the New Mexico Environment Department in November 2013 which, among other things, calls for balanced draft upgrades on San Juan Unit 1 to reduce particulate matter emissions. PNM, the operator of San Juan, is currently installing SNCR. Balanced draft modifications to San Juan Unit 1were completed in June 2015. TEP’s share of the balanced draft upgrades was approximately $22 million. In December 2015, PNM obtained New Mexico Public Regulation Commission approval to shut down Units 2 and 3 at San Juan.

At December 31, 2015, the net book value of TEP's share in San Juan Unit 2, including construction work in progress, was $104 million. Consistent with the 2013 Rate Order, TEP has requested authorization from the ACC to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case.

Four Corners

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

Sundt

In June 2014, the EPA issued a final rule that would require TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Unit 4 of the H. Wilson Sundt Generating Station (Sundt) continues to use coal as a fuel source; or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. Under the rule, TEP is required to notify the EPA of its decision by March 2017.

At December 31, 2015, the net book value of the Sundt coal handling facilities was $16 million. In August 2015, TEP exhausted its existing coal supply at Sundt and has been operating Sundt with natural gas as a primary fuel source. TEP expects to retire the Sundt coal handling facilities earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case. The estimated NO_x emissions control costs in the table above will not be expended if Sundt's coal handling facilities are retired early.

Greenhouse Gas Regulation

In August 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil fueled power plants. 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. States are required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. States that receive an extension must submit a final completed plan to the EPA by September 2018. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. TEP cannot predict the ultimate outcome of these matters.

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

TEP's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016, the Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP rule. TEP will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling. TEP anticipates that the ruling will likely delay the requirement to submit a plan or request an extension under the CPP by September 2016.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste under Subtitle D of the Resource Conservation and Recovery Act for disposal in landfills and/or surface impoundments while allowing for the continued recycling of coal ash. TEP does not own or operate any impoundments. Under the rule, the Springerville Generating Station (Springerville) ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP’s share of the cost at Springerville is estimated to be $2 million, the majority of which is expected to be capital expenditures. TEP currently estimates its share of the costs to be $5 million at Four Corners, $3 million at Navajo, and less than $1 million at San Juan, the majority of which are expected to be capital expenditures.

See Capital Expenditures above for TEP's actual and forecasted environmental-related cost.

CRITICAL ACCOUNTING POLICIES

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

Accounting for Regulated Operations

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

At December 31, 2015, regulatory liabilities net of regulatory assets totaled $96 million at TEP. There are no current or expected proposals or changes in the regulatory environment that impact our ability to apply accounting guidance for regulated operations. If we conclude, in a future period, that our operations no longer meet the criteria in this guidance, we would reflect our regulatory pension assets in AOCI and recognize the impact of other regulatory assets and liabilities in the income statement, both of which would be material to our financial statements. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory matters.

Accounting for Asset Retirement Obligations

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

TEP identified legal obligations to retire generation plant assets specified in land leases for its jointly-owned Navajo and Four Corners Generating Stations. The land on which these stations reside is leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at expiration of the leases. TEP also has certain environmental obligations at the Luna, San Juan, Sundt and Springerville Generating Stations. TEP estimates that its share of the AROs to remove the Navajo and Four Corners facilities and settle the Luna, San Juan, Sundt, Gila River and Springerville environmental obligations will be approximately $157 million at the retirement dates. Additionally, TEP entered into ground lease agreements with certain land owners for the installation of photovoltaic (PV) assets. The provisions of the PV ground leases require TEP to remove the PV facilities upon expiration of the leases. TEP's ARO related to the PV assets is estimated to be approximately $30 million at the retirement dates. No other legal obligations to retire generation plant assets were identified.

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

The total net present value of TEP's ARO liability was $32 million at December 31, 2015. ARO liabilities are reported in Regulatory and Other Liabilities—Other on the Consolidated Balance Sheets. See Note 3 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding AROs.

Additionally, the authorized depreciation rates for TEP include a component designed to accrue the future costs of retiring assets for which no legal obligations exist. The accumulated balances at December 31, 2015 represent non-legal asset retirement obligation accruals, less actual removal costs incurred, net of salvage proceeds realized, and are included in Regulatory and Other Liabilities, Regulatory Liabilities on the Consolidated Balance Sheets. See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Pension and Other Retiree Benefit Plan Assumptions

TEP records plan assets, obligations, and expenses related to pension and other retiree benefit plans based on actuarial valuations, which include key assumptions on discount rates, expected returns on plan assets, compensation increases, and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. The effect of modifications is generally recorded or amortized over future periods. We believe that the assumptions used in recording obligations are reasonable based on prior experience, market conditions, and the advice of plan actuaries. Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K discusses the assumptions used in the calculation of pension plan and other retiree plan obligations.

TEP is required to recognize the underfunded status of its defined benefit pension and other retiree plans as a liability. The underfunded status is the difference between the fair value of the plans assets and the projected benefit obligation for pension plans or accumulated retiree benefit obligation for other retiree benefit plans. As the funded status, discount rates, and actuarial facts change, the liability will vary significantly in future years. TEP records the underfunded amount for its pension and other retiree obligations as a liability and a regulatory asset to reflect expected recovery of pension and other retiree obligations through the rates charged to retail customers.

At December 31, 2015, TEP discounted its future pension plan obligations at rates between 4.5% and 4.6% and its other retiree plan obligations at a rate of 4.2%. The discount rate for future pension plan and other retiree plan obligations is determined annually based on the rates currently available on high-quality, non-callable, long-term bonds. The discount rate is based on a corporate yield curve using an average yield between the 60th and 90th percentile of AA-graded U.S. corporate bonds with future cash flows that match the timing and amount of expected future benefit payments. For TEP's pension plans, a 25-basis point change in the discount rate would increase or decrease the Projected Benefit Obligation (PBO) by approximately $15 million and the plan expense by $1 million. For TEP's other retiree benefit plan, a 25-basis point change in the discount rate would increase or decrease the Accumulated Postretirement Benefit Obligation (APBO) by approximately $2 million.

We measured service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. As discussed in Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K, at the end of 2015, we changed our approach to determine the service and interest cost components of pension and other postretirement benefit expense for future years. For 2016, we elected to measure service and interest costs by applying the specific spot rates along that yield curve to the plan's liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. The use of this approach reduces 2016 service and interest cost by $4 million with a corresponding increase to regulatory assets. This change does not affect the measurement of our plan obligations nor the funded status of our plans.

TEP calculates the market-related value of pension plan assets using the fair value of the assets on the measurement date. TEP assumed that its pension plans' assets would generate a long-term rate of return of 7% at December 31, 2015. In establishing its assumption as to the expected return on assets, TEP reviews the asset allocation and develops return assumptions for each asset class based on advice from an investment consultant and the pension's actuary that includes both historical performance analysis and forward-looking views of the financial markets. Pension expense decreases as the expected rate of return on assets increases. A 25-basis point change in the expected return on assets would impact pension expense in 2015 by $1 million.

TEP adopted the RP-2014 mortality table projected with improvement scale MP-2015 with 15 year convergence and 0.75% long term rate to measure December 31, 2015 pension obligations, whereas RP-2000 mortality table with Scale BB was utilized for the December 31, 2014 measurement.

TEP used a current year health care cost trend rate of 7.6% in valuing its retiree benefit obligation at December 31, 2015. This rate reflects both market conditions and historical experience. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage point change in assumed health care cost trend rates would increase the retiree benefit obligation by approximately $6 million and decrease the retiree benefit obligation by approximately $5 million. In addition, a one-percentage point change in assumed health care cost trend rates would change the related 2016 plan expense by approximately $1 million.

In 2016, TEP will incur pension costs of approximately $11 million and other retiree benefit costs of approximately $5 million. TEP expects to charge approximately $13 million of these costs to O&M expense, and $3 million to capital. TEP expects to make pension plan contributions of $10 million in 2016. In 2009, TEP established a VEBA trust to fund its other retiree benefit plan. In 2016, TEP expects to make benefit payments to retirees under the retiree benefit plan of approximately $5 million and contributions to the VEBA trust of approximately $1 million, net of distributions.

Accounting for Derivative Instruments and Hedging Activities

Commodity Derivative Contracts

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

For all commodity derivative instruments that do not meet the normal purchase or normal sale scope exception, we recognize derivative instruments as either assets or liabilities on the Consolidated Balance Sheets and measure those instruments at fair value. Unrealized gains and losses on commodity derivative contracts entered into for retail customer load are recorded as either a regulatory asset or regulatory liability on the balance sheet based on our ability

to recover the costs of hedging activities entered into to mitigate energy price risk for retail customers. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets through the PPFAC mechanism.
The market prices used to determine fair values for TEP’s derivative instruments at December 31, 2015, are estimated based on various factors including broker quotes, exchange prices, over the counter prices, and time value.

TEP manages the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using a standardized agreement, which allows for the netting of current period exposures to and from a single counterparty.

Interest Rate Swaps

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates tied to LIBOR on the Springerville Common Facilities Lease. As of December 31, 2015, approximately $29 million of variable rate lease debt for the Springerville Common Facilities Lease had been hedged through an interest rate swap agreement through January 2020.

Revenue Recognition

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

Plant Asset Depreciable Lives

TEP has significant investments in electric generation assets and electric transmission and distribution assets. We calculate depreciation expense based on our estimate of the useful lives of our plant assets and expected net removal costs. The useful lives of plant assets are further detailed in Note 3 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Changes to depreciation estimates resulting from a change of estimated service life or removal costs could have a significant impact on the amount of depreciation expense recorded in the income statement. The ACC approves depreciation rates for all generation and distribution assets. Depreciation rates for such assets cannot be changed without the ACC's approval. TEP's transmission assets are subject to the jurisdiction of the FERC. See Note 1 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding depreciation rates.

Income Taxes

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

A valuation allowance is established against deferred tax assets for which management believes it is more likely than not that the deferred asset will not be realized. In making this judgment, management evaluates all available evidence and gives more weight to objective verifiable evidence. At December 31, 2015, TEP had a $4 million valuation allowance. See Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

TEP's primary market risks include fluctuations in interest rates, returns on marketable securities, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. We 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.

See Forward-Looking Information for additional information.

Risk Management Committee

We have a Risk Management Committee responsible for the oversight of commodity price risk and credit risk related to the wholesale energy marketing and power procurement activities of TEP. Our Risk Management Committee, which meets on a quarterly basis and as needed, consists of officers from the finance, accounting, legal, wholesale marketing, and generation operations departments of TEP. To limit TEP's exposure to commodity price risk, the Risk Management Committee sets trading and hedging policies and limits, which are reviewed frequently to respond to constantly changing market conditions. To limit TEP's exposure to credit risk, the Risk Management Committee reviews counterparty credit exposure as well as credit policies and limits.

Interest Rate Risk

Long-Term Debt

TEP is exposed to interest rate risk resulting from changes in interest rates on certain of its variable rate debt obligations. TEP had $137 million in tax-exempt variable rate debt outstanding at December 31, 2015. The outstanding debt included one series of bonds for which interest rates are reset weekly and one series of bonds for which interest rates are reset monthly. The weighted average weekly rate (including LOC fees and remarketing fees) was 1.24% in 2015 and 1.46% in 2014. The average weekly interest rate ranged from 0.93% - 1.42% in 2015 and 1.40% - 1.75% in 2014. The monthly rate is based on a percentage of an index equal to one-month LIBOR plus a credit spread. The average monthly rate was 0.81% in 2015 and 0.87% in 2014. The monthly rate ranged from 0.79% - 0.87% in 2015 and 0.85% - 0.95% in 2014.

Although short-term interest rates were low and stable in 2015 and 2014, TEP may still be subject to volatility in its tax-exempt variable rate debt. A 100 basis point increase in average interest rates on this debt, over a twelve month period, would result in a decrease in TEP's pre-tax net income of approximately $1 million.

TEP can manage its exposure to variable interest rate risk by entering into interest rate swaps and financing transactions to rebalance its mix of variable rate and fixed rate long-term debt. TEP has a fixed-for-floating interest rate swap in place to hedge floating interest rate risk associated with a portion of its Springerville Common Facilities lease debt. The notional amount of the swap is $29 million at December 31, 2015. The notional amount of lease debt that was unhedged as of December 31, 2015 was $13 million. TEP did not have any other interest rate swaps at December 31, 2015.

Interest Rate Swap

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

(in millions)	2015	2014	2013
Net Unrealized Gains	$1	$2	$4

Revolving Credit Facilities

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

Marketable Securities Risk

The majority of TEP’s pension plan assets, as well as assets associated with other employee benefit obligations, are investments in equity and debt securities. These investments are exposed to price fluctuations in equity markets and changes in interest rates. Of the assets held for employee benefit obligations, the pension plan assets comprise the largest portion. The pension plan assets will help fund defined retirement benefits for substantially all of our employees. Declines in the values of these assets could increase required employer contributions, which would adversely affect cash flows. Declines in values could also increase the reported pension expense, adversely affecting TEP’s results of operations.

Commodity Price Risk

TEP is exposed to commodity price risk primarily relating to changes in the market price of electricity, natural gas, and coal. This risk is mitigated through hedging practices and a PPFAC mechanism which fully recovers the actual retail fuel and purchased power costs incurred on a timely basis from TEP’s retail customers. The PPFAC mechanism has a forward component and a true-up component. The forward component of the PPFAC rate is based on forecasted fuel and purchased power costs. The true-up component reconciles actual fuel and purchased power costs with the amounts collected in the prior year and any amounts under/over-collected will be collected from/credited to customers. If the actual price of power is higher than the forecasted PPFAC rate, TEP's operating cash flows are reduced by the price difference until the subsequent 12-month period when the true-up component is adjusted to allow the recovery of this difference.

Purchases and Sales of Energy

To manage its exposure to energy price risk, TEP enters into forward contracts to buy or sell energy at a specified price and future delivery period. Generally, TEP commits to future sales based on expected excess generating capability, forward prices and generation costs, using a diversified market approach to provide a balance between long-term, mid-term, and spot energy sales. TEP generally enters into forward purchases during its summer peaking period to ensure it can meet its load and reserve requirements, and account for other contracts and resource contingencies. TEP also enters into limited forward purchases and sales to optimize its resource portfolio and take advantage of geographical differences in price. These positions are managed on both a volumetric and dollar basis and are closely monitored using risk management policies and procedures overseen by the Risk Management Committee. For example, the risk management policies provide that TEP should not take a short physical position in the third quarter and must have owned generation backing up all physical forward sales positions at the time the sale is made. TEP’s risk management policies also place limits on the duration of transactions in both gas and power.

TEP enters into some forward contracts considered to be normal purchases and sales of electric energy and are therefore not accounted for as derivatives. TEP records revenues on its “normal sales” and expenses on its “normal purchases” in the period in which the energy is delivered. TEP also enters into forward contracts that are not considered to be “normal purchases and sales” and therefore are accounted for as derivatives. When TEP has derivative forward contracts, it marks them to market using actively quoted prices obtained from brokers for power traded over-the-counter at Palo Verde and at other southwestern U.S. trading hubs. TEP believes that these broker quotations used to calculate the mark-to-market values represent accurate measures of the fair values of TEP’s positions because of the short-term nature of TEP’s positions, as limited by risk management policies, and the liquidity in the short-term market.

Long-Term Wholesale Sales

TEP has several long-term wholesale agreements for the sale of energy. Sales under some of these agreements are based on indexed energy prices. Changes in the price of power affect TEP's revenue and income from these agreements.

Natural Gas

TEP is also subject to commodity price risk from changes in the price of natural gas. In addition to energy from its coal-fired facilities, TEP typically uses power purchases, supplemented by generation from its gas-fired units to meet the summer peak demands of its retail customers and to meet local reliability needs. Some of these purchased power contracts are indexed to natural gas prices. Short-term and spot power purchase prices are also closely correlated to natural gas prices. Due to its increasing gas and purchased power usage, TEP hedges a portion of its total natural gas exposure from plant fuel, gas-indexed power purchases, and spot market purchases with various instruments up to

three years in advance. TEP purchases its remaining gas fuel and power needs in the spot and short-term markets.
As required by fair value accounting rules, for the year ended December 31, 2015, TEP considered the impact of non-performance risk in the measurement of fair value of its derivative assets and derivative liabilities net of collateral posted.

To adjust the value of its commodity derivatives to fair value, TEP adjusted regulatory assets or regulatory liabilities as follows:

(in millions)	2015	2014	2013
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$6	$(18)	$—

The table below displays the valuation methodologies and maturities of TEP's power and gas derivative contracts by source of fair value:

	Unrealized Gain (Loss) of TEP's Hedging Activities			
	Maturity 0 – 6 months	Maturity 6 – 12 months	Maturity over 1 yr.	Total Unrealized Gain (Loss)
(in millions)	December 31, 2015			
Prices Actively Quoted	$(7)	$(1)	$(2)	$(10)
Prices Based on Models and Other Valuation Methods	(1)	—	—	(1)
Total	$(8)	$(1)	$(2)	$(11)

Sensitivity Analysis of Derivatives

TEP uses sensitivity analysis to measure the impact of favorable and unfavorable changes in market prices on the fair value of its derivative forward contracts. TEP records unrealized gains and losses as either a regulatory asset or regulatory liability. As contracts settle, the unrealized gains and losses are reversed and realized gains or losses are recorded to the PPFAC. For TEP's non-cash flow power hedges, a 10% change in the market price of power would affect unrealized positions reported as a regulatory asset or regulatory liability by approximately $1 million; for gas swaps and collar contracts, a 10% change in the market price of energy would affect unrealized positions reported as a regulatory asset or liability by approximately $3 million.

Coal

TEP is subject to commodity price risk from changes in the price of coal used to fuel its coal-fired generating plants. This risk is mitigated through the use of long term coal supply agreements with limited price volatility.

TEP's coal supply contract for Springerville Units 1 and 2 expires in 2020, at which time a new coal purchase agreement will be negotiated. TEP expects coal reserves from the Lee Ranch - El Segundo mine, which supplies Springerville Units 1 and 2 to be sufficient to supply the estimated requirements for the units presently estimated remaining lives. The current coal price is determined by the cost of Powder River Basin coal delivered to Springerville Unit 3 subject to a floor and ceiling.

TEP participates in jointly-owned generating facilities at Four Corners, Navajo, and San Juan, where coal supplies are received under contracts administered by the operating agents. The coal contracts at Four Corners and Navajo expire in 2031 and 2019, respectively. The new coal supply contract with Westmoreland for San Juan, effective January 31, 2016, expires in 2022. At December 31, 2015, TEP had contracts to purchase coal for use at the jointly-owned facilities and expected its estimated average annual cost for the next three years to be $51 million and $22 million thereafter through 2031. Contemporaneous with the new San Juan coal supply contract in January 2016, additional estimated minimum purchase obligations are $21 million in 2016, $23 million in 2017, $24 million in 2018 and 2019, $23 million in 2020, and $22 million through the end of the contract.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources and Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Credit Risk

TEP is exposed to credit risk in its energy-related marketing activities related to potential non-performance by counterparties. We manage the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using standard agreements which allow for the netting of current period exposures to and from a single counterparty. We calculate counterparty credit exposure by adding any outstanding receivable (net of amounts payable if a netting agreement exists) to the mark-to-market value of any forward contracts. If exposure exceeds credit limits or contractual collateral thresholds, we may request that a counterparty provide credit enhancement in the form of cash collateral or an LOC.

TEP has entered into short-term and long-term transactions with several financial institution counterparties with terms of one month through three years. As of December 31, 2015, the credit exposure to TEP from financial institution counterparties was less than $1 million.

As of December 31, 2015, TEP's total credit exposure related to its wholesale marketing and gas hedging activities was approximately $10 million. TEP did not have any exposure to non-investment grade counterparties.
At December 31, 2015, TEP posted no cash collateral and less than $1 million in LOCs as credit enhancements with its counterparties, and did not hold any collateral from its counterparties.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

TEP's management is responsible for establishing and maintaining adequate internal control over financial reporting. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of TEP's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the 2013 COSO Internal Control – Integrated Framework.

Based on management's assessment using those criteria, management has concluded that, as of December 31, 2015, TEP's internal control over financial reporting was effective.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Tucson Electric Power Company as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in stockholder’s equity and cash flows for each of the two years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tucson Electric Power Company at December 31, 2015 and 2014, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Ernst & Young LLP

Calgary, Canada

February 18, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholder of Tucson Electric Power Company

In our opinion, the consolidated statements of income, comprehensive income, changes in stockholder’s equity and cash flows for the year ended December 31, 2013 present fairly, in all material respects, the results of operations and cash flows of Tucson Electric Power Company and its subsidiaries for the year ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers
LLP

PricewaterhouseCoopers LLP

Phoenix, Arizona

February 25, 2014, except for the effects of the revision discussed in Note 1 (not presented herein) to the consolidated financial statements appearing under Item 8 of the Company’s 2014 annual report on Form 10-K, as to which the date is August 14, 2014

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

	Year Ended December 31,		
	2015	2014	2013
Operating Revenues			
Electric Retail Sales	$1,021,543	$970,145	$934,357
Electric Wholesale Sales	167,020	158,323	132,500
Other Revenues	117,981	141,433	129,833
Total Operating Revenues	1,306,544	1,269,901	1,196,690
Operating Expenses			
Fuel	305,559	297,537	325,903
Purchased Power	124,764	152,922	112,452
Transmission and Other PPFAC Recoverable Costs	24,798	18,179	12,233
Increase (Decrease) to Reflect PPFAC Recovery Treatment	39,787	(11,194)	(12,458)
Total Fuel and Purchased Power	494,908	457,444	438,130
Operations and Maintenance	345,356	378,877	335,321
Depreciation	138,093	126,520	118,076
Amortization	19,261	28,567	31,294
Taxes Other Than Income Taxes	49,623	47,805	43,498
Total Operating Expenses	1,047,241	1,039,213	966,319
Operating Income	259,303	230,688	230,371
Other Income (Deductions)			
Interest Income	93	208	120
Other Income	6,647	8,598	5,770
Other Expense	(2,833)	(12,735)	(10,715)
Appreciation (Depreciation) in Value of Investments	(142)	1,371	2,833
Total Other Income (Deductions)	3,765	(2,558)	(1,992)
Interest Expense			
Long-Term Debt	61,159	60,577	56,378
Capital Leases	3,994	10,249	25,140
Other Interest Expense	1,134	810	87
Interest Capitalized	(2,732)	(3,755)	(2,554)
Total Interest Expense	63,555	67,881	79,051
Income Before Income Taxes	199,513	160,249	149,328
Income Tax Expense	71,719	57,911	47,986
Net Income	$127,794	$102,338	$101,342

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

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

	Year Ended December 31,		
	2015	2014	2013
Comprehensive Income			
Net Income	$127,794	$102,338	$101,342
Other Comprehensive Income (Loss)			
Net Changes in Fair Value of Cash Flow Hedges:			
Net of Income Tax (Expense) Benefit of ($821), ($1,140), and ($1,793)	1,261	1,675	2,738
Supplemental Executive Retirement Plan Adjustments:			
Net of Income Tax (Expense) Benefit of ($63), $1,068, and ($572)	101	(1,725)	916
Total Other Comprehensive Income (Loss), Net of Tax	1,362	(50)	3,654
Total Comprehensive Income	$129,156	$102,288	$104,996

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

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

	Year Ended December 31,		
	2015	2014	2013
Cash Flows from Operating Activities			
Net Income	$127,794	$102,338	$101,342
Adjustments to Reconcile Net Income To Net Cash Flows from Operating Activities:			
Depreciation Expense	138,093	126,520	118,076
Amortization Expense	19,261	28,567	31,294
Amortization of Debt Issuance Costs	3,043	2,626	2,452
Provision for Springerville Unit 1 - Third-Party Owners Unrealized Revenue	22,627	—	—
Use of Renewable Energy Credits for Compliance	19,731	17,818	15,990
Deferred Income Taxes	72,026	59,024	58,100
Pension and Retiree Expense	18,588	13,648	19,878
Pension and Retiree Funding	(30,682)	(14,388)	(27,636)
Allowance for Equity Funds Used During Construction	(5,352)	(6,677)	(4,526)
LFCR and DSM Revenues	(14,646)	(12,937)	(2,575)
Increase (Decrease) to Reflect PPFAC Recovery Treatment	39,787	(11,194)	(12,458)
Fortis Acquisition Direct Customer Benefit	—	18,870	—
Change in Current Assets and Current Liabilities:			
Accounts Receivable	(25,690)	(14,261)	824
Materials, Supplies, and Fuel Inventory	(8,758)	666	16,145
Accounts Payable	(23,149)	10,712	334
Regulatory Liabilities	(2,977)	8,388	3,331
Other, Net	15,238	(16,057)	25,620
Net Cash Flows—Operating Activities	364,934	313,663	346,191
Cash Flows from Investing Activities			
Capital Expenditures	(333,841)	(323,524)	(252,848)
Purchase of Gila River Unit 3	—	(163,938)	—
Purchase of Springerville Coal Handling Facilities Lease Assets	(120,312)	—	—
Purchase of Springerville Unit 1 Lease Assets	(45,753)	(19,608)	—
Proceeds from Sale of Springerville Coal Handling Facilities	23,656	—	—
Purchase of Intangibles - Renewable Energy Credits	(29,184)	(28,334)	(23,280)
Return of Investments in Springerville Lease Debt	—	—	9,104
Contributions in Aid of Construction	4,517	15,903	3,959
Other, Net	(1,974)	1,863	3,403
Net Cash Flows—Investing Activities	(502,891)	(517,638)	(259,662)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facilities	148,000	275,000	78,000
Repayments of Borrowings Under Revolving Credit Facilities	(233,000)	(190,000)	(78,000)
Proceeds from Borrowings Under Term Loan	130,000	—	—
Repayments of Borrowings Under Term Loan	(130,000)	—	—
Proceeds from Issuance of Long-Term Debt	299,019	149,168	—
Repayments of Long-Term Debt	(208,600)	—	—
Dividends Paid to Parent	(50,000)	(40,000)	(40,000)
Payments of Capital Lease Obligations	(13,464)	(165,145)	(99,621)
Payment of Debt Issue/Retirement Costs	(3,942)	(1,856)	(1,865)
Contribution from Parent	180,000	225,000	—

Other, Net	1,458	643	549
Net Cash Flows—Financing Activities	119,471	252,810	(140,937)
Net Increase (Decrease) in Cash and Cash Equivalents	(18,486)	48,835	(54,408)
Cash and Cash Equivalents, Beginning of Period	74,170	25,335	79,743
Cash and Cash Equivalents, End of Period	$55,684	$74,170	$25,335

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

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

	December 31, 2015	2014
ASSETS		
Utility Plant		
Plant in Service	$5,618,435	$5,175,148
Utility Plant Under Capital Leases	131,705	667,157
Construction Work in Progress	102,028	109,070
Total Utility Plant	5,852,168	5,951,375
Less Accumulated Depreciation and Amortization	(2,194,301)	(2,052,216)
Less Accumulated Amortization of Capital Lease Assets	(99,638)	(473,969)
Total Utility Plant, Net	3,558,229	3,425,190
Investments and Other Property	39,569	37,599
Current Assets		
Cash and Cash Equivalents	55,684	74,170
Accounts Receivable, Net	136,682	131,799
Fuel Inventory	34,600	36,368
Materials and Supplies	94,003	86,750
Regulatory Assets	51,841	69,383
Derivative Instruments	1,808	1,633
Assets Held for Sale, Net	21,550	—
Other	25,904	21,010
Total Current Assets	422,072	421,113
Regulatory and Other Assets		
Regulatory Assets	212,312	223,192
Derivative Instruments	430	300
Other	16,866	12,436
Total Regulatory and Other Assets	229,608	235,928
Total Assets	$4,249,478	$4,119,830

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

(Continued)

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

	December 31, 2015	December 31, 2014
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity:		
Common Stock (No Par Value, 75,000,000 Shares Authorized, 32,139,434 Shares Outstanding at December 31, 2015 and 2014)	$1,296,539	$1,116,539
Capital Stock Expense	(6,357)	(6,357)
Accumulated Earnings	189,317	111,523
Accumulated Other Comprehensive Loss	(4,564)	(5,926)
Total Common Stock Equity	1,474,935	1,215,779
Preferred Stock (No Par Value, 1,000,000 Shares Authorized, None Outstanding at December 31, 2015 and 2014)	—	—
Capital Lease Obligations	55,324	69,438
Long-Term Debt, Net	1,451,720	1,361,828
Total Capitalization	2,981,979	2,647,045
Current Liabilities		
Current Obligations Under Capital Leases	14,114	173,822
Borrowings Under Revolving Credit Facilities	—	85,000
Accounts Payable	86,274	113,413
Accrued Taxes Other than Income Taxes	37,577	36,110
Accrued Employee Expenses	27,718	15,679
Accrued Interest	14,246	21,021
Regulatory Liabilities	53,077	38,847
Customer Deposits	20,349	20,339
Derivative Instruments	12,174	18,874
Other	7,533	9,673
Total Current Liabilities	273,062	532,778
Regulatory and Other Liabilities		
Deferred Income Taxes, Net	468,024	389,540
Regulatory Liabilities	307,286	321,186
Pension and Other Postretirement Benefits	120,336	138,319
Derivative Instruments	4,067	6,288
Other	94,724	84,674
Total Regulatory and Other Liabilities	994,437	940,007
Commitments and Contingencies		
Total Capitalization and Other Liabilities	$4,249,478	$4,119,830

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

(Concluded)

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

	Common Stock	Capital Stock Expense	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances at December 31, 2012	$888,971	$(6,357)	$ (12,157)	$ (9,530)	$ 860,927
Net Income			101,342		101,342
Other Comprehensive Income (Loss), Net of Tax				3,654	3,654
Dividends Declared to Parent			(40,000)		(40,000)
Balances at December 31, 2013	888,971	(6,357)	49,185	(5,876)	925,923
Net Income			102,338		102,338
Other Comprehensive Income (Loss), Net of Tax				(50)	(50)
Dividends Declared to Parent			(40,000)		(40,000)
Contribution from Parent	225,000				225,000
Other	2,568				2,568
Balances at December 31, 2014	1,116,539	(6,357)	111,523	(5,926)	1,215,779
Net Income			127,794		127,794
Other Comprehensive Income (Loss), Net of Tax				1,362	1,362
Dividends Declared to Parent			(50,000)		(50,000)
Contribution from Parent	180,000				180,000
Balances at December 31, 2015	$1,296,539	$(6,357)	$ 189,317	$ (4,564)	$ 1,474,935

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

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NOTES TO 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 417,000 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. TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis Inc. (Fortis).

References in these notes to "we" and "our" are to TEP.

FORTIS ACQUISITION OF UNS ENERGY

UNS Energy, the parent of TEP, was acquired by Fortis for $60.25 per share of UNS Energy common stock in cash, effective August 15, 2014. The Arizona Corporation Commission's (ACC) 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;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital; and
- Fortis making an equity investment of at least $220 million to UNS Energy and its regulated subsidiaries, including TEP. Following the UNS Energy acquisition, Fortis exceeded the investment requirement by contributing $287 million to UNS Energy through December 31, 2014. UNS Energy then contributed $225 million to TEP.

As a result of the acquisition being completed, TEP recorded approximately $15 million, through August 2014, as its allocated share of acquisition-related expenses, in addition to the customer bill credits discussed above. Acquisition-related expenses, reported in Operations and Maintenance and Other Expense, include investment banker fees, legal expenses, and accelerated expenses for certain share-based compensation awards. See Note 9 for additional information regarding share-based compensation.

BASIS OF PRESENTATION

TEP's consolidated financial statements and disclosures are presented in accordance with Generally Accepted Accounting Principles (GAAP) in the United States which includes specific accounting guidance for regulated operations. See Note 2 for additional information regarding regulatory matters. The consolidated financial statements include the accounts of TEP and its subsidiaries. In the consolidation process, accounts of the parent and subsidiaries are combined and intercompany balances and transactions are eliminated. TEP jointly owns several generating stations and transmission facilities with non-affiliated entities. TEP's proportionate share of jointly owned facilities is recorded as Utility Plant on the Consolidated Balance Sheets, and our proportionate share of the operating costs associated with these facilities is included on the consolidated statements of income. See Note 3 for additional information regarding Utility Plant.

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 acquisition were recorded by FortisUS Inc., a wholly owned subsidiary of Fortis.

Certain amounts from prior periods have been reclassified to conform to the current year presentation. Most notably, in 2014, TEP elected to change its method of reporting cash flows from the direct to the indirect method to conform to Fortis' presentation election.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2015, we adopted accounting guidance that:

- limits the circumstances under which a disposal may be reported as a discontinued operation and requires new disclosures. The adoption of this guidance did not have any impact on our disclosures, financial condition, results of operations, or cash flows as we did not have any activities that required application of this accounting guidance.
-

requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, rather than as deferred charges. The adoption of this standard resulted in reclassification of debt issuance costs from Other Current Assets and Other Assets to Long-Term Debt on the Consolidated Balance Sheets. TEP will continue to account for debt issuance costs related to line-of-credit arrangements as an asset. TEP reclassified $11 million at December 31, 2014 from Other Current Assets and Other Assets to Long-Term Debt to conform to the current year presentation.

- simplifies the presentation of deferred taxes by requiring deferred tax assets and liabilities to be classified as noncurrent on the balance sheet. The adoption of this standard resulted in a reclassification of deferred income taxes from Deferred Income Taxes - Current Assets to Deferred Income Taxes - Regulatory and Other Liabilities. TEP reclassified $102 million at December 31, 2014 from Deferred Income Taxes - Current Assets to Deferred Income Taxes - Regulatory and Other Liabilities to conform to the current year presentation.

USE OF ACCOUNTING ESTIMATES

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

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

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

ACCOUNTING FOR REGULATED OPERATIONS

We apply accounting standards that recognize the economic effects of rate regulation. As a result, we capitalize certain costs that would be recorded as expense or in Accumulated Other Comprehensive Income (AOCI) by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in the rates charged to retail customers or to wholesale customers through transmission tariffs. Regulatory liabilities generally represent expected future costs that have already been collected from customers or amounts that are expected to be returned to customers through future rate reductions.

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

TEP applies regulatory accounting as the following conditions exist:

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

CASH AND CASH EQUIVALENTS

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

RESTRICTED CASH

Cash balances that are restricted regarding withdrawal or usage based on contractual or regulatory considerations are reported in Investments and Other Property on the balance sheets. Restricted cash was $4 million at December 31, 2015 and $2 million at December 31, 2014.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ALLOWANCE FOR DOUBTFUL ACCOUNTS

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

	Year Ended December 31,		
(in millions)	2015	2014	2013
Beginning of Period	$5	$5	$5
Increases:			
Charged to Operating Revenues	23	—	—
Charged to Operating Expenses	2	2	2
Write-offs	(3)	(2)	(2)
End of Period	$27	$5	$5

The Allowance for Doubtful Accounts increased in 2015 due to Third-Party Owners' claims at Springerville Unit 1. See Note 7 for additional information regarding the Third-Party Owners' claims.

INVENTORY

We value materials, supplies, and fuel inventory at the lower of weighted average cost or market, unless evidence indicates that the weighted average cost (even if in excess of market) will be recovered in retail rates. We capitalize handling and procurement costs (such as labor, overhead costs, and transportation costs) as part of the cost of the inventory. Materials and Supplies consist of generation, transmission, and distribution construction and repair materials.

UTILITY PLANT

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

We record the cost of repairs and maintenance, including planned major overhauls, to Operations and Maintenance (O&M) expense in the income statement as costs are incurred.

When a unit of regulated property is retired, we reduce accumulated depreciation by the original cost plus removal costs less any salvage value. There is no income statement impact.

AFUDC and Capitalized Interest

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

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

	2015	2014	2013
Average AFUDC Rates	6.12 %	7.30 %	7.38 %

Depreciation

We compute depreciation for owned utility plant on a group method straight-line basis at depreciation rates based on the economic lives of the assets. See Note 3 for additional information regarding Utility Plant. The ACC approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Depreciation rates are based on average useful lives and include estimates for salvage value and removal costs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Below are the summarized average annual depreciation rates for all utility plant:

	2015	2014	2013
Average Annual Depreciation Rates	2.83 %	2.99 %	3.16 %

Utility Plant Under Capital Leases

TEP finances the facilities at Springerville used in common with Springerville Unit 1 and Unit 2 (Springerville Common Facilities) with capital leases. The capital lease expense incurred consists of Amortization Expense and Interest Expense—Capital Leases. See Note 3 for additional information regarding Utility Plant and Note 6 for additional information related to the lease terms.

Computer Software Costs

We capitalize costs incurred to purchase and develop internal use computer software and amortize those costs over the estimated economic life of the product. If the software is no longer useful, we immediately charge capitalized computer software costs to expense.

ASSET RETIREMENT OBLIGATIONS

TEP has identified legal Asset Retirement Obligations (AROs) related to the retirement of certain generation assets. Additionally, TEP incurred AROs related to its photovoltaic assets as a result of entering into various ground leases or easement agreements. We record a liability for a legal ARO in the period in which it is incurred if it can be reasonably estimated. When a new obligation is recorded, we capitalize the cost of the liability by increasing the carrying amount of the related long-lived asset. We record the increase in the liability due to the passage of time by recognizing accretion expense in O&M expense and depreciate the capitalized cost over the useful life of the related asset or, when applicable, the terms of the lease subject to ARO requirements. TEP defers costs associated with the majority of its legal AROs as regulatory assets based on the ACC's approval of these costs in TEP's depreciation rates.

Depreciation rates also include a component for estimated future removal costs that have not been identified as legal obligations. We recover those amounts in the rates charged to retail customers and have recorded an obligation for estimated costs of removal as regulatory liabilities.

EVALUATION OF ASSETS FOR IMPAIRMENT

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

DEFERRED FINANCING COSTS

We defer the costs to issue debt and amortize such costs to interest expense on a straight-line basis over the life of the debt as this approximates the effective interest method. Deferred debt issuance costs are presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees, and printing costs. TEP accounts for debt issuance costs related to line-of-credit arrangements as an asset.

We defer and amortize the gains and losses on reacquired debt associated with regulated operations to interest expense over the remaining life of the original debt.

OPERATING REVENUES

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

For purchased power and wholesale sales contracts that are settled financially, TEP nets the sales contracts with the purchase power contracts and reflects the net amount as Electric Wholesale Sales.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP recognizes monthly management fees in Other Revenues as the operator of 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 Agriculture Improvement and Power District (SRP). Additionally, Other Revenues include reimbursements from Tri-State and SRP for various operating expenses at Springerville and for the use of the Springerville Common Facilities and the Springerville Coal Handling Facilities. The offsetting expenses are recorded in the respective line items of the income statements based on the nature of services provided. As the operating agent for Tri-State and SRP, TEP may earn performance incentives based on unit availability which are recognized in Other Revenues in the period earned.

The ACC has authorized mechanisms for Lost Fixed Cost Recovery (LFCR) related to kilowatt-hour (kWh) sales lost due to Energy Efficiency Standards (EE Standards) and distributed generation. We recognize revenues in the period that verifiable energy savings occur. Revenue recognition related to the LFCR creates a regulatory asset until such time as the revenue is collected.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

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

RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAMS

The ACC's Renewable Energy Standard (RES) requires TEP to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. TEP must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out this plan is recovered from retail customers through the RES surcharge. The ACC has also approved recovery of operating costs, depreciation, property taxes, and a return on investments in company-owned solar projects through the RES tariff until such costs are reflected in retail customer rates.

TEP is required to implement cost-effective Demand Side Management (DSM) programs to comply with the ACC's EE Standards. The EE Standards provide for a DSM surcharge to recover, from retail customers, the costs to implement DSM programs. The EE Standards require increasing annual targeted retail kWh savings equal to 22% by 2020.

Any RES or DSM surcharge collections above or below the costs incurred to implement the plans are deferred and reflected in the financial statements as a regulatory asset or liability. TEP recognizes RES and DSM surcharge revenue in Electric Retail Sales in amounts necessary to offset recognized qualifying expenditures.

RENEWABLE ENERGY CREDITS

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

When RECs are purchased, TEP records the cost of the RECs (an indefinite-lived intangible asset) as Other Assets, and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, TEP recognizes Purchased Power expense and Other Revenues in an equal amount. See Note 2 for additional information regarding regulatory matters.

INCOME TAXES

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

Tax benefits are recognized when it is more likely than not that a tax position will be sustained upon examination by the tax authorities based on the technical merits of the position. The tax benefit recorded is the largest amount that is more than 50%

likely to be realized upon ultimate settlement with the tax authority, assuming full knowledge of the position and all relevant facts. Interest expense accruals relating to income tax obligations are recorded in Other Interest Expense.

Prior to 1990, TEP flowed through to ratepayers certain accelerated tax benefits related to utility plant as the benefits were recognized on tax returns. Regulatory Assets include income taxes recoverable through future rates, which reflects the future revenues due to TEP from ratepayers as these tax benefits reverse. See Note 2 for additional information regarding regulatory matters.

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

Income tax liabilities are allocated to TEP based on its taxable income as reported in the FortisUS Inc. consolidated tax return.

TAXES OTHER THAN INCOME TAXES

We act as conduits or collection agents for sales taxes, utility taxes, franchise fees, and regulatory assessments. As we bill customers for these taxes and assessments, we record trade receivables. At the same time, we record liabilities payable to governmental agencies on the balance sheet for these taxes and assessments. These amounts are not reflected in the income statements.

FAIR VALUE

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

DERIVATIVE INSTRUMENTS

We use various physical and financial derivative instruments, including forward contracts, financial swaps, and call and put options, to meet forecasted load and reserve requirements, to reduce our exposure to energy commodity price volatility and to hedge our interest rate risk exposure. For all derivative instruments that do not meet the normal purchase or normal sale scope exception, we recognize derivative instruments as either assets or liabilities on the Consolidated Balance Sheets and measure those instruments at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation.

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

PENSION AND OTHER RETIREE BENEFITS

We sponsor noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on years of service and average compensation. We also provide limited health care and life insurance benefits for retirees.

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

Additionally, we maintain a Supplemental Executive Retirement Plan (SERP) for senior management. Changes in SERP benefit obligations are recognized as a component of AOCI.

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

NOTE 2. REGULATORY MATTERS

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

2015 RATE CASE

In November 2015, TEP filed a general rate case with the ACC based on a test year ended June 30, 2015. The filing requests that new rates be implemented by January 1, 2017.

The key provisions of TEP's general rate case include:

- a Base Rate increase of $110 million, or 12%, compared with adjusted test year revenues;
- a 7.34% return on original cost rate base of $2.1 billion;
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of the San Juan Generating Station (San Juan) Unit 2 and the H. Wilson Sundt Generating Station (Sundt) Coal Handling Facilities due to early retirement;
- a request for authority to begin using the Third-Party Owners' portion of Unit 1 of the Springerville Generating Station (Springerville Unit 1) that is available to TEP for dispatch to serve retail customers' needs and to recover the related operating costs through the PPFAC; and
- rate design changes that would reduce the reliance on volumetric sales to recover fixed costs and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service.

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

COST RECOVERY MECHANISMS

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

Purchased Power and Fuel Adjustment Clause

TEP's PPFAC rate is adjusted annually each April 1st and goes into effect for the subsequent 12-month period unless modified by the ACC. The PPFAC rate includes: (i) a forward component which attempts to recover or refund the difference between forecasted fuel costs and those embedded in the current PPFAC and fuel 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 $18 million at December 31, 2015 and under-collected by $19 million at December 31, 2014.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The PPFAC rates during the periods reported were as follows:

Period	Cents per kWh
April 2015 through March 2016	0.68
October 2014 through March 2015 [1]	0.50
May 2014 through September 2014 [1]	0.10
July 2013 through April 2014 [2]	(0.14)
January 2013 through June 2013	0.77

(1) The ACC approved a two-step increase to shift a higher level of recovery into the winter season.

(2) The effective date of the 2012 PPFAC rate reduction was deferred to coincide with the effective date of the 2013 Rate Order.

San Juan Mine Fire Insurance Proceeds

In September 2011, a fire at the underground mine providing coal to San Juan caused interruptions to mining operations and resulted in increased fuel costs. The 2013 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 (SJCC) and distribution of insurance proceeds to San Juan participants. TEP received insurance proceeds of $1 million in 2015 and $8 million in 2014. The insurance proceeds offset the deferred fuel costs and are included in the Statements of Cash Flows as an operating activity. The remaining $1 million of unreimbursed fuel costs will be recovered through the PPFAC, in accordance with the 2013 Rate Order.

Renewable Energy Standards

The ACC’s RES requires TEP and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. Affected utilities must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge until such costs are reflected in TEP’s Base Rates. The associated lost revenues attributable to meeting distributed generation targets will be partially recovered through the LFCR.

In July 2015, TEP submitted its application for the 2016 RES implementation plan that includes a budget of $57 million, which will be partially offset by applying approximately $9 million of previously recovered carryover funds. TEP proposed to recover $48 million through the RES surcharge. The budget will fund the following: (i) the above market cost of renewable energy purchases; (ii) previously awarded performance-based incentives for customer installed distributed generation; (iii) depreciation and a return on TEP's investments in company-owned solar projects; and (iv) various other program costs. TEP expects to receive a decision on the application in the first half of 2016. TEP expects to recognize approximately $9 million of revenue in 2016 as a return on company-owned solar projects.

TEP met the overall 2015 RES renewable energy requirement of 5% of retail Kilowatt-hour (kWh) sales and expects to meet the 2016 requirement of 6% of retail kWh sales. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain distributed generation REC, which are used to demonstrate compliance with the distributed generation requirement, the company has requested a waiver of the RES distributed generation requirements in its 2016 RES implementation plan.

Energy Efficiency Standards

In 2010, the ACC approved new EE Standards designed to require electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. Since the implementation of the EE Standards, TEP’s cumulative annual energy savings are approximately 9.3% of 2015 retail kWh sales. TEP’s compliance with the EE Standards is governed by the ACC’s approval of its annual implementation plan.

The EE Standards provide for a DSM surcharge for regulated utilities to recover the costs to implement DSM programs as well as an annual performance incentive. TEP recorded $3 million in 2015, $2 million in 2014, and less than $1 million in 2013 related to performance. The performance incentive is recorded in the first quarter of the year and is included in Electric Retail Sales on the Consolidated Statements of Income.

In February 2016, the ACC approved TEP’s 2016 energy efficiency implementation plan. Under the 2016 plan, TEP has been approved to recover approximately $14 million from retail customers and will offer customers new and existing DSM programs. Energy savings realized through the programs will count toward Arizona's EE Standard and the associated lost revenue will be partially recovered through the LFCR.

Lost Fixed Cost Recovery Mechanism

The 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 energy efficiency programs and distributed generation targets. TEP records a regulatory asset and recognizes LFCR revenues when the amounts are verifiable, regardless of when the lost retail kWh sales occur. For recovery of the LFCR regulatory asset, TEP is required to file an annual LFCR adjustment request with the ACC for the LFCR revenues recognized in the prior year. The recovery is subject to a year-over-year cap of 1% of TEP's total retail revenues.

TEP recorded a regulatory asset and recognized LFCR revenues of $12 million in 2015, $11 million in 2014, and $2 million in 2013 related to reductions in retail kWh sales for the prior years. LFCR revenues are included in Electric Retail Sales on the Consolidated Statements of Income.

Appellate Review of Rate Decisions

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

REGULATORY ASSETS AND LIABILITIES

Regulatory assets are either being collected in Retail Rates or are expected to be collected through Retail Rates in a future period. With the exception of interest earned on under-recovered PPFAC costs and the ECA, we do not earn a return on regulatory assets. Regulatory liabilities represent items that we either expect to pay to customers through billing reductions in future periods or plan to use for the purpose for which they were collected from customers. Regulatory assets and liabilities recorded on the Consolidated Balance Sheets are summarized below:

	December 31,	
(in millions)	2015	2014
Regulatory Assets		
Pension and Other Retiree Benefits (Note 8)	$120	$126
Final Mine Reclamation and Retiree Health Care Costs (1)	28	29
Income Taxes Recoverable through Future Rates (2)	26	31
Property Tax Deferrals (3)	21	21
Springerville Unit 1 Leasehold Improvements - Third Party Owners (4)	21	—
LFCR and DSM	16	12
Derivatives (Note 11)	12	18
PPFAC	—	19
Springerville Purchase Deferrals (5)	—	16
Other Regulatory Assets	20	20
Total Regulatory Assets	264	292
Less Current Portion	52	69
Total Non-Current Regulatory Assets	$212	$223
Regulatory Liabilities		
Net Cost of Removal for Interim Retirements (6)	$264	$265
Deferred Investment Tax Credits (7)	32	41
RES	25	28
PPFAC	18	—
Other Regulatory Liabilities	21	26
Total Regulatory Liabilities	360	360
Less Current Portion	53	39
Total Non-Current Regulatory Liabilities	$307	$321

(1) Final Mine Reclamation and Retiree Health Care Costs represent costs associated with TEP's jointly-owned facilities at San Juan, Four Corners, and Navajo. TEP has the option to recognize its liability associated with final reclamation and retiree health care obligations at present or future value. TEP has elected to recognize these costs at future value and is permitted to fully recover these costs through the PPFAC when paid. TEP expects to make continuous payments through 2037.

(2) Income Taxes Recoverable through Future Rates are amortized over the life of the assets. See Note 1 and Note 12 for additional information regarding income taxes.

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

(4) Upon expiration of Springerville Unit 1 capital leases in January 2015, TEP recorded a regulatory asset for unamortized leasehold improvement costs that relate to third-party ownership interests. These leasehold improvements, previously recorded in Plant in Service on the Consolidated Balance Sheets, represent investments TEP made through the end of the lease term to ensure that the Springerville Unit 1 facilities continued providing

safe, reliable service to TEP's customers. In the 2013 Rate Order, TEP received ACC authorization to recover Springerville Unit 1 leasehold improvement costs over a 10-year amortization period.

(5) TEP deferred the increase in lease interest expense relating to the purchase commitments for Springerville Unit 1 and the Springerville Coal Handling Facilities to a regulatory asset because TEP believes the full purchase price is recoverable in rate base. See Note 6 for additional information regarding the Springerville leases.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(7) Accumulated Deferred Investment Tax Credit (ITC) represents federal energy credits generated after 2011 that are amortized over the tax life of the underlying asset.

IMPACTS OF REGULATORY ACCOUNTING

If we determine that we no longer meet the criteria for continued application of regulatory accounting, we would be required to write off our regulatory assets and liabilities related to those operations not meeting the regulatory accounting requirements. Discontinuation of regulatory accounting could have a material impact on our financial statements.

NOTE 3. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Utility Plant in Service by major class:

	December 31,	
(in millions)	2015	2014
Plant in Service		
Electric Generation Plant	$2,612	$2,388
Electric Transmission Plant	1,008	890
Electric Distribution Plant	1,456	1,398
General Plant	358	338
Intangible Plant - Software Costs (1) (2)	172	149
Intangible Plant - Transmission Rights and Other	7	8
Electric Plant Held for Future Use	5	4
Total Plant in Service	$5,618	$5,175
Utility Plant under Capital Leases (3)	$132	$667

(1) Unamortized computer software costs were $45 million and $31 million as of December 31, 2015 and 2014, respectively.

(2) The amortization of computer software costs was $14 million in 2015, $17 million in 2014, and $14 million in 2013.

(3) TEP purchased certain Springerville facilities leased interests in 2015 and 2014. See Note 6 for additional information regarding the Springerville leases.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Utility Plant under Capital Leases

All utility plant under capital leases is used in generation operations and amortized over the primary lease term. See Note 6 for additional information regarding capital leases. At December 31, 2015, the utility plant under capital leases represents an undivided one-half interest in certain Springerville Common Facilities. The following table shows the amount of lease expense incurred for generation-related capital leases:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Lease Expense			
Interest Expense – Included in:			
Capital Leases	$4	$10	$25
Operating Expenses – Fuel	—	1	2
Amortization of Capital Lease Assets – Included in:			
Operating Expenses – Fuel	2	6	5
Operating Expenses – Amortization	6	16	15
Total Lease Expense	$12	$33	$47

Utility plant depreciation rates and approximate average remaining service lives based on the most recent depreciation studies available for the major classes of Utility Plant in Service at December 31, 2015, were as follows:

	Annual Depreciation Rate (1)	Average Remaining Life in Years
Electric Generation Plant	3.31%	22
Electric Transmission Plant	1.48%	32
Electric Distribution Plant	2.08%	35
General Plant	5.48%	11
Intangible Plant (2)	Various	Various

(1) The depreciation rates represent a composite of the depreciation rates of assets within each major class of utility plant.

(2) The majority of TEP's investment in intangible plant represents computer software. Computer software is being amortized over its expected useful life of three to five years for smaller application software and average remaining life of three to eight years for large enterprise software.

GILA RIVER ACQUISITION

In December 2014, TEP and UNS Electric, Inc. (UNS Electric) acquired Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 megawatts (MW) located in Gila Bend, Arizona, from a subsidiary of Entegra Power Group LLC. TEP purchased a 75% undivided interest in Gila River Unit 3 (413 MW) for $164 million, and UNS Electric purchased the remaining 25% undivided interest.

TEP’s purchase of Gila River Unit 3 was intended to replace the reduction of 195 MW of output from Springerville Unit 1 and the 170 MW of capacity expected to be retired at San Juan in 2017.

The transaction was accounted for using the acquisition method of accounting which requires that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The following table summarizes the assets acquired and liabilities assumed as of the acquisition date:

(in millions)	
Utility Plant, Net	$163
Materials and Supplies	2
ARO Obligation Assumed (1)	(1)
Total Purchase Price	$164

(1)

The ARO obligation was recorded at net present value in Regulatory and Other Liabilities - Other on TEP's Consolidated Balance Sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

JOINTLY-OWNED FACILITIES

In addition to Gila River Unit 3, at December 31, 2015, TEP was a participant in the following jointly-owned generating stations and transmission systems:

(in millions)	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Book Value
San Juan Units 1 and 2	50.0%	$486	$12	$251	$247
Navajo Units 1, 2, and 3	7.5%	148	2	112	38
Four Corners Units 4 and 5	7.0%	102	9	77	34
Luna Energy Facility	33.3%	54	—	—	54
Gila River Unit 3	75.0%	198	2	56	144
Gila River Common Facilities	18.8%	25	—	7	18
Springerville Unit 1 (1)	49.5%	319	8	174	153
Springerville Coal Handling Facility (2)	65.9%	164	1	65	100
Transmission Facilities	Various	383	1	172	212
Total		$1,879	$35	$914	$1,000

(1) TEP is obligated to operate the unit for the Third-Party Owners under existing agreements. The Owner Trustees and Co-Trustees are obligated to compensate TEP for their pro rata share of expenses. See Note 6 for additional information regarding the purchase of leased interest. See Note 7 for additional information regarding Springerville Unit 1.

(2) TEP owns an additional 17.05% undivided interest in the Springerville Coal Handling Facilities classified as Assets Held for Sale on the Consolidated Balance Sheets. See Note 6 for additional information regarding the Springerville Coal Handling Facilities lease interests.

As participants in these jointly-owned facilities, we are responsible for our share of operating and capital costs for the above facilities. We account for our share of operating expenses and utility plant costs related to these facilities using proportionate consolidation.

RETIREMENTS

San Juan

In October 2014, the EPA published a final rule approving a State Implementation Plan (SIP) covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017. TEP is a participant in San Juan Unit 2. Given the closure of two units and the desire of certain participants to exit their ownership in San Juan, PNM and the other participants, including TEP, negotiated restructured ownership agreements which became effective upon the sale of San Juan Coal Company's (SJCC) stock in January 2016. As a condition of the New Mexico Public Regulatory Commission's (NMPRC) approval of the early retirement of San Juan Units 2 and 3, PNM is required to make a filing with the NMPRC in 2018 to demonstrate the ongoing economic viability of San Juan beyond 2022. Under the new restructured ownership agreements, TEP and the other remaining participants have the option to exit their remaining ownership interest in San Juan as of June 30, 2022.

At December 31, 2015, the net book value of TEP's share in San Juan Unit 2, including construction work in progress, was $104 million. Consistent with the 2013 Rate Order, TEP has requested authorization from the ACC to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case. See Note 2 for additional information regarding the 2015 Rate Case.

Sundt

In June 2014, the EPA issued a final rule that would require TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Sundt Unit 4 continues to use coal as a fuel source; or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. Under the rule, TEP is required to notify the EPA of its decision by March 2017.

At December 31, 2015, the net book value of the Sundt coal handling facilities was $16 million. In August 2015, TEP exhausted its existing coal supply at Sundt and has been operating Sundt with natural gas as a primary fuel source. TEP expects to retire the Sundt coal handling facilities earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered net book value in its 2015 Rate Case. See Note 2 for additional information regarding the 2015 Rate Case.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ASSET RETIREMENT OBLIGATIONS

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

	December 31,	
(in millions)	2015	2014
Beginning of Period	$28	$22
Liabilities Incurred	4	5
Accretion Expense or Regulatory Deferral	1	1
Revisions to the Present Value of Estimated Cash Flows [1]	(1)	—
End of Period	$32	$28

(1) Primarily related to changes in expected cost estimates, in conjunction with changes of asset retirement dates of generating facilities.

NOTE 4. ACCOUNTS RECEIVABLE

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

	December 31,	
(in millions)	2015	2014
Customer	$79	$78
Due from Affiliates (Note 5)	7	5
Unbilled	39	37
Other	39	17
Allowance for Doubtful Accounts [1]	(27)	(5)
Accounts Receivable, Net	$137	$132

(1) The Allowance for Doubtful Accounts increased in 2015 due to the Third-Party Owners' claims at Springerville Unit 1. See Note 7 for additional information regarding the Third-Party Owners' claims.

NOTE 5. RELATED PARTY TRANSACTIONS

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31,	
(in millions)	2015	2014
Receivables from Related Parties		
UNS Electric	$6	$4
UNS Gas	1	1
Total Due from Related Parties	$7	$5
Payables to Related Parties		
SES	$2	$2
UNS Electric	2	1
UNS Energy	2	—
Total Due to Related Parties	$6	$3

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

	Year Ended December 31,		
(in millions)	2015	2014	2013
Wholesale Sales - TEP to UNS Electric (1)	$8	$4	$1
Wholesale Sales - UNS Electric to TEP (1)	1	4	2
Control Area Services - TEP to UNS Electric (2)	2	3	4
Common Costs - TEP to UNS Energy Affiliates (3)	12	13	12
Supplemental Workforce - SES to TEP (4)	16	16	16
Corporate Services - UNS Energy to TEP (5)	7	14	5
Corporate Services - UNS Energy Affiliates to TEP (6)	1	1	1

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

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

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

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

(5) Costs for corporate services at UNS Energy include Fortis management fees, legal fees, and audit fees which are allocated to its subsidiaries using the Massachusetts Formula, an industry accepted method of allocating common costs to affiliated entities. TEP's allocation is approximately 81% of UNS Energy's allocated costs. In 2015, these costs included approximately $5 million in Fortis management fees, which began in January 2015 following the August 2014 acquisition. In 2014, these costs included approximately $12 million in acquisition-related costs (excluding TEP allocated labor related charges).

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

CONTRIBUTION FROM PARENT

In June 2015, UNS Energy made an equity contribution to TEP of $180 million. TEP used proceeds from the equity contribution to repay the outstanding balances under TEP's revolving credit facilities. The remaining balance of the proceeds was used to redeem bonds in August 2015 and to provide additional liquidity to TEP. See Note 6 for additional information regarding the August 2015 bond redemption. TEP received contributions of $225 million from

UNS Energy in 2014 and no contributions in 2013.

DIVIDEND PAID

TEP declared and paid $50 million in dividends to UNS Energy in 2015 and $40 million in 2014 and 2013.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The ACC's approval of the acquisition of UNS Energy by Fortis, in August 2014, contained a condition restricting subsidiary dividend payments to UNS Energy by TEP to no more than 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital as accounted for in accordance with GAAP. The ratios used to determine the dividend restrictions will be calculated for each calendar year and reported to the ACC annually beginning on April 1, 2016. As of December 31, 2015, TEP had not reached the 50 percent of total capital and was therefore still restricted by the condition contained in the ACC's approval order.

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

LONG-TERM DEBT

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

(dollars in millions)			December 31,	
Debt (1)	Interest Rate	Maturity Date (3)	2015	2014
Notes				
2011 Notes	5.15%	2021	$250	$250
2012 Notes	3.85%	2023	150	150
2014 Notes	5.00%	2044	150	150
2015 Notes	3.05%	2025	300	—
Tax Exempt Local Furnishings Bonds				
1982 Pima A Irvington Project	Reset Weekly (2)	2022	—	39
1982 Pima A TEP Projects	Reset Weekly (2)	2022	—	40
2008 Pima B	5.75%	2029	—	130
2010 Pima A	5.25%	2040	100	100
2012 Pima A	4.50%	2030	16	16
2013 Pima A	4.00%	2029	91	91
2013 Apache A	Reset Monthly (2)	2032	100	100
Tax Exempt Pollution Control Bonds				
2009 Pima A	4.95%	2020	80	80
2009 Coconino A	5.13%	2032	15	15
2010 Coconino A	Reset Weekly (2)	2032	37	37
2012 Apache A	4.50%	2030	177	177
Total Long-Term Debt			1,466	1,375
Less Unamortized Discount and Debt Issuance Costs			14	13
Total Long-Term Debt, Net			$1,452	$1,362

(1) As of December 31, 2015, all of TEP's debt is unsecured, with the exception of the 2010 Coconino A variable rate bonds, which are backed by a LOC.

(2) For variable rate debt for which rates are reset weekly, the weighted average rate (including LOC fees and remarketing fees) was 1.24% in 2015 and 1.46% in 2014. The average weekly interest rate ranged from 0.93% - 1.42% in 2015 and 1.40% - 1.75% during 2014. For variable rate debt for which rates are reset monthly, the rate is based on a percentage of an index equal to one-month London Interbank Offered Rate (LIBOR) plus a credit spread. The average monthly rate was 0.81% in 2015 and 0.87% in 2014. The monthly interest rate ranged from 0.79% - 0.87% in 2015 and 0.85% - 0.95% in 2014.

(3) The 2010 Coconino A variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019. The 2013 Apache A variable rate bonds are subject to mandatory

tender for purchase in 2018.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEBT ISSUANCES AND REDEMPTIONS

Fixed Rate Debt

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

In January 2015, TEP purchased $130 million aggregate principal amount of unsecured tax exempt Industrial Development Revenue Bonds (IDRBs) issued in June 2008 by the Industrial Development Authority (IDA) of Pima County, Arizona for the benefit of TEP. The multi-modal bonds mature in September 2029. At December 31, 2015, TEP had not remarketed the repurchased bonds and as a result the bonds were not recorded in Long-Term Debt on the Consolidated Balance Sheets.

In March 2014, TEP issued and sold $150 million of unsecured notes. TEP may redeem the notes prior to September 2043, with a make-whole premium plus accrued interest. After September 2043, TEP may redeem the notes at par plus accrued interest.

Variable Rate Debt

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

In September 2014, TEP's interest rate swap entered into in August 2009 expired. The interest rate swap had the economic effect of converting $50 million of variable rate bonds to a fixed rate of 2.40% from September 2009 to September 2014.

CREDIT AGREEMENTS

In October 2015, TEP entered into an unsecured credit agreement (2015 Credit Agreement) replacing the 2010 Credit Agreement. The 2015 Credit Agreement provides for a $250 million revolving credit commitment and LOC facility. The LOC sublimit is $50 million. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. All amounts outstanding under the facility will be due in October 2020, the termination date. The 2015 Credit Agreement allows for two one-year extensions of the facility if certain conditions are satisfied.

Interest rates and fees under the 2015 Credit Agreement are based on a pricing grid tied to TEP’s credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.00% for Eurodollar loans or Alternate Base Rate with no spread for Alternate Base Rate loans.

At December 31, 2015, TEP had no borrowings outstanding included in Current Liabilities on the Consolidated Balance Sheets. As of February 17, 2016, there was $250 million available under the 2015 Credit Agreement's revolving credit and LOC facilities.

In 2015, TEP terminated both the 2010 and 2014 Credit Agreements. The amended 2010 Credit Agreement provided for a $200 million revolving credit commitment and LOCs supporting variable-rate, tax-exempt bonds, with an expiration date of November 2016. The 2014 Credit Agreement, entered into in December 2014, provided for a $130 million term loan commitment and a $70 million revolving credit commitment, with an expiration date of November 2015. At December 31, 2014, TEP had $85 million in total borrowings outstanding under these agreements which were included in Current Liabilities on the Consolidated Balance Sheets.

2010 REIMBURSEMENT AGREEMENT

In December 2010, a $37 million LOC was issued to support certain variable rate tax-exempt bonds pursuant to the 2010 Reimbursement Agreement. The LOC had an expiration date of December 2014. In February 2014, the LOC was amended to extend the expiration date from 2014 to 2019. Fees are payable on the aggregate outstanding amount of the LOC at a rate of 0.75% per annum based on TEP's current credit ratings.

COVENANT COMPLIANCE

Certain of our credit and long-term debt agreements contain restrictive covenants, including restrictions on additional indebtedness, liens to secure indebtedness, mergers, sales of assets, transactions with affiliates, and restricted payments. At December 31, 2015, we were in compliance with the terms of our long-term debt, 2015 Credit Agreement, 2013 Covenants Agreement, and 2010 Reimbursement Agreement.

CAPITAL LEASE OBLIGATIONS

The following table details Capital Lease Obligation on TEP's Consolidated Balance Sheets:

	December 31,	
(in millions)	2015	2014
Springerville Unit 1	$—	$43
Springerville Coal Handling Facilities	—	117
Springerville Common Facilities	69	83
Total Capital Lease Obligations	69	243
Less Current Obligations Under Capital Leases	14	174
Total Capital Lease Obligations, Net	$55	$69

Springerville Unit 1 Capital Lease Purchases

In December 2014, TEP purchased a 10.6% leased interest in Springerville Unit 1 representing 41 MW of capacity for the appraised value of $20 million. In January 2015, upon expiration of the lease term, TEP purchased leased interests comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million, the appraised value. Upon purchase of the leased interests, TEP reduced Capital Lease Obligations on the Consolidated Balance Sheets for the purchase price.

With the completion of the purchases, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. TEP is obligated to operate the unit for the Third-Party Owners under existing agreements. The Owner Trustees and Co-Trustees are obligated to compensate TEP for their pro rata share of expenses. See Note 7 for more information regarding claims relating to Springerville Unit 1.

Springerville Coal Handling Facilities Lease Purchase

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

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

Tri-State, the lessee of Springerville Unit 3, is obligated to either: (i) buy a 17.05% undivided interest in the facilities for approximately $24 million; or (ii) continue to make payments to TEP for the use of the facilities. Tri-State has until April 2016 to exercise its purchase option. At December 31, 2015, Tri-State's 17.05% undivided interest in the Springerville Coal Handling Facilities is classified as Assets Held for Sale on the Consolidated Balance Sheets.

Springerville Common Facilities Leases

The Springerville Common Facilities Leases have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025. TEP may also exercise a fixed-price purchase provision. The fixed prices for the acquisition of the interests in the common facilities are $38 million in 2017 and $68 million in 2021.

TEP entered into agreements with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that contain the following conditions if the Common Facilities Leases are not renewed:

- TEP will exercise the purchase options under these contracts;
- SRP will be obligated to buy a portion of these facilities; and
- Tri-State will be obligated to either: (i) buy a portion of these facilities; or (ii) continue making payments to TEP for the use of these facilities.

TEP entered into an interest rate swap in 2006 that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease debt. The swap has the effect of fixing the benchmark LIBOR rate on a portion of the amortizing principal balance. The swap matures in January 2020 with interest on the lease debt payable at a swapped rate of

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5.77% plus an applicable margin per the lease agreement. The lease debt outstanding at December 31, 2015 consisted of a notional amount of $29 million on which interest was fixed by the swap and a notional amount of $13 million of debt that was not hedged. The applicable margin was 1.88% and 1.75% at December 31, 2015 and 2014, respectively. TEP recorded the interest rate swap as a cash flow hedge for financial reporting purposes. See Note 11 for additional information.

DEBT MATURITIES

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

(in millions)	Long-Term Debt Maturities [1]	Capital Lease Obligations	Total [2]
2016	$—	$15	$15
2017	—	16	16
2018	100	11	111
2019	37	11	48
2020	80	18	98
Total 2016 - 2020	217	71	288
Thereafter	1,249	—	1,249
Less: Imputed Interest	—	(2)	(2)
Total	$1,466	$69	$1,535

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

(2) Total long-term debt is not reduced by $11 million of related unamortized debt issuance costs and $3 million of unamortized original issue discount.

NOTE 7. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2015, TEP had the following firm, non-cancellable, minimum purchase obligations and operating leases:

(in millions)	2016	2017	2018	2019	2020	Thereafter	Total
Fuel, Including Transportation	$78	$76	$49	$49	$41	$287	$580
Purchased Power	28	—	—	—	—	—	28
Transmission	6	6	6	4	3	13	38
Renewable Power Purchase Agreements	61	61	61	61	60	750	1,054
RES Performance-Based Incentives	8	8	8	8	8	67	107
Operating Leases:							
Land Easements and Rights-of-Way	1	1	1	1	1	77	82
Operating Leases Other	1	1	1	1	1	4	9
Total Purchase Commitments	$183	$153	$126	$124	$114	$1,198	$1,898

Fuel, Including Transportation

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

clause that will affect the future cost. TEP expects to spend more than the minimum purchase obligations to meet its fuel requirements. TEP's fuel costs are recoverable from customers through the PPFAC.

Contemporaneously with the sale of SJCC's stock in January 2016, the existing coal sale agreement terminated and a new Coal Supply Agreement (CSA) became effective. The new CSA is between SJCC and PNM and continues through June 30, 2022. TEP is not a party to the new CSA, but has minimum purchase obligations under restructured ownership agreements at San Juan. Estimated future payments, not included in the table above, are $21 million in 2016, $23 million in 2017, $24 million in 2018 and 2019, $23 million in 2020, and $22 million through the end of the contract.

TEP has firm transportation agreements with capacity sufficient to meet its load requirements. These contracts expire in various years between 2016 and 2040.

Purchased Power and Transmission

TEP has agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. In general, these contracts provide for capacity payments and energy payments based on actual power taken under the contracts and expire in 2016. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table are based on projected market prices as of December 31, 2015.

TEP has agreements with other utilities to provide transmission services over lines that are part of the Western Interconnection, a regional grid in the United States. These contracts expire in various years between 2018 and 2028. TEP's purchased power and transmission costs are recoverable from customers through the PPFAC mechanism.

Renewable Power Purchase Agreements and RES Performance-Based Incentives

TEP enters into long-term renewable power purchase agreements which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. A portion of the cost of renewable energy is recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. These contracts expire in various years between 2030 and 2035.

In February 2016, a facility achieved commercial operation status. The related contract expires in 2036. Estimated future payments, not included in the table above, are $3 million in each of 2016 through 2020 and $43 million through the end of the contract.

TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance-Based Incentives (PBIs) and are paid in contractually agreed-upon intervals (usually quarterly) based on metered renewable energy production. PBIs are recoverable through the RES tariff.

See Note 2 for additional information regarding TEP's RES tariff.

Operating Leases

Our operating lease expense is primarily for rail cars, office facilities, land easements, and rights-of-way with varying terms, provisions, and expiration dates. TEP's operating lease expense totaled $3 million in 2015 and 2014 and $2 million in 2013.

CONTINGENCIES

Navajo Generating Station Lease Extension

Navajo Generating Station (Navajo) is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. The Navajo Nation signed a lease amendment in 2013 that would extend the lease from 2019 through 2044. The participants in Navajo, including TEP, have not signed the lease amendment because certain participants have expressed an interest in discontinuing their participation in Navajo. Negotiations between the participants are ongoing, and all parties will likely agree to the terms. To become effective, this lease amendment must be signed by all of the participants, approved by the Department of the Interior, and is subject to environmental reviews. Once the lease amendment becomes effective, the participants will be responsible for additional lease costs from the date the Navajo Nation signed the lease amendment. TEP owns 7.5% of Navajo. In 2015, TEP recorded additional estimated lease expense of approximately $1 million with the expectation that the lease amendment will become effective. TEP's Consolidated Balance Sheets reflect a total liability related

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to the lease amendment of $3 million and $2 million at December 31, 2015 and 2014, respectively, recorded in Regulatory and Other Liabilities—Other.

Claims Related to Springerville Generating Station Unit 1

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

On December 19, 2014, the Third-Party Owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County (New York Action). In response to motions filed by TEP to dismiss various counts and compel arbitration of certain of the matters alleged, and the court's subsequent ruling on the motions, the Third-Party Owners have amended the complaint three times, dropping certain of the allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases and that TEP has breached the lease transaction documents by refusing to pay certain of the Third-Party Owners' claimed expenses. The third amended complaint seeks $71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The Third-Party Owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action. In November 2015, the Third-Party Owners filed a motion for summary judgment on their claim that TEP has failed to pay certain of the Third-Party Owners' claimed expenses.

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

In April 2015, TEP filed a demand for arbitration with the American Arbitration Association (AAA) seeking an award of the Owner Trustees and Co-Trustees' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. In June 2015, the Third-Party Owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The Third-Party Owners' arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the Third-Party Owners' fees and expenses. TEP and the Third-Party Owners have since agreed to consolidate their arbitration demands into one proceeding. In August 2015, the Third-Party Owners filed an amended arbitration demand adding claims that TEP has converted the Third-Party Owners' water rights and certain emission reduction payments and that TEP is improperly dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. In October 2015, the arbitration panel granted TEP's motion for interim relief, ordering the Owner Trustees and Co-Trustees to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners' motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners' unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling, when economical, the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 14, 2015. The arbitration hearing is scheduled for July 2016.

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

As of December 31, 2015, TEP has billed the Third-Party Owners approximately $23 million for their pro-rata share of Springerville Unit 1 expenses and $4 million for their pro-rata share of capital expenditures, none of which had been paid as of February 17, 2016.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1, and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time. TEP intends to vigorously defend itself against the claims asserted by the Third-Party Owners and to vigorously pursue the claims it has asserted against the Third-Party Owners.

TEP and the Third-Party Owners have agreed to stay these litigation matters relating to Springerville Unit 1 in furtherance of settlement negotiations. However, there is no assurance that a settlement will be reached or that the litigation will not continue.

Claims Related to San Juan Generating Station

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

In February 2013, WildEarth Guardians (WEG) filed a Petition for Review in the U.S. District Court of Colorado against the Office of Surface Mining (OSM) challenging federal administrative decisions affecting seven different mines in four states issued at various times from 2007 through 2012. In its petition, WEG challenges several unrelated mining plan modification approvals, which were each separately approved by OSM. Of the fifteen claims for relief in the WEG Petition, two concern SJCC’s San Juan mine. WEG’s allegations concerning the San Juan mine arise from OSM administrative actions in 2008. WEG alleges various National Environmental Policy Act (NEPA) violations against OSM, including, but not limited to, OSM’s alleged failure to provide requisite public notice and participation, alleged failure to analyze certain environmental impacts, and alleged reliance on outdated and insufficient documents. WEG’s petition seeks various forms of relief, including a finding that the federal defendants violated NEPA by approving the mine plans, voiding, reversing, and remanding the various mining modification approvals, enjoining the federal defendants from re-issuing the mining plan approvals for the mines until compliance with NEPA has been demonstrated, and enjoining operations at the seven mines. SJCC intervened in this matter. SJCC was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now proceeding. The parties have requested the court to stay this matter until April 2016, in furtherance of settlement negotiations. If WEG ultimately obtains the relief it has requested, such a ruling could require significant expenditures to reconfigure operations at the San Juan mine, impact the production of coal, and impact the economic viability of the San Juan mine and San Juan. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the U.S. 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 sought 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.

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. In June 2015, APS, the operator of Four Corners, announced a settlement with the Environmental Protection Agency (EPA) for outstanding environmental issues related to New Source Review provisions under the Clean Air Act. The settlement calls for environmental upgrades including Selective Catalytic Reduction (SCR) upgrades already planned for under the Regional Haze regulation, environmental mitigation projects, and civil penalties. A consent decree reflecting terms of the settlement was entered by the court in August 2015, effectively closing the case. TEP's share of the additional capital, excluding the SCR upgrades, is approximately $2 million over the three year period it will take to construct the upgrades. TEP’s share of the annual O&M expenses is approximately $1 million. In addition, TEP recorded less than $1 million for its share of the one-time charges for environmental mitigation projects and civil penalties.

In May 2013, the New Mexico Taxation and Revenue Department (NMTRD) issued a notice of assessment for coal severance tax, penalties, and interest totaling $30 million to the coal supplier at Four Corners. TEP's share of the assessment is $1 million based on our ownership percentage. In December 2013, the coal supplier and Four Corners’ operating agent filed a claim contesting the validity of the assessment on behalf of the participants in Four Corners, who will be liable for their share of any resulting liabilities. In June 2015, the U.S. District Court ruled in favor of the Four Corners' participants. NMTRD filed an appeal of the decision in August 2015. TEP cannot predict the final outcome or timing of resolution of these claims.

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 $43 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The reclamation liability recorded was $25 million and $22 million at December 31, 2015 and 2014, respectively.

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 expected inflation rate. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements’ terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements.

TEP’s PPFAC allows us to pass through final reclamation costs, as a component of fuel cost, 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.

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-kilo-volt (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 maintain the Certificate of Environmental Compatibility (CEC) previously granted by the ACC for this project in contemplation of using 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 and recorded a regulatory asset of $5 million for the balance deemed probable of recovery in TEP's next FERC rate case.

Performance Guarantees

TEP has joint participation agreements with participants at Navajo, San Juan, Four Corners, and the Luna Energy Facility (Luna). The participants in each of the generating stations, including TEP, have guaranteed certain performance obligations. Specifically, in the event of payment default, the non-defaulting participants have agreed to bear a proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generating capacity of the defaulting participant. As of December 31, 2015, there have been no such payment defaults under any of the participation agreements. The Navajo participation agreement expires in 2019, San Juan in 2022, Four Corners in 2041, and Luna in 2046.

NOTE 8. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

TEP has three noncontributory, defined benefit pension plans. Benefits are based on years of service and average compensation. Two of the plans are for substantially all employees. We fund those plans by contributing at least the minimum amount required under the Internal Revenue Service (IRS) regulations. We also maintain a Supplemental Executive Retirement Plan (SERP) for executive management.

OTHER RETIREE BENEFIT PLANS

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP funds its other retiree benefits for classified employees through a Voluntary Employee Beneficiary Association (VEBA). TEP contributed $4 million in 2015 and $3 million in 2014 and 2013 to the VEBA. Other retiree benefits for unclassified employees are self-funded.

REGULATORY RECOVERY

We record changes in our non-SERP pension plans and other retiree benefit plan, not yet reflected in net periodic benefit cost, as a regulatory asset, as such amounts are probable of future recovery in the rates charged to retail customers. Changes in the SERP obligation, not yet reflected in net periodic benefit cost, are recorded in Other Comprehensive Income since SERP expense is not currently recoverable in rates.

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

	Pension Benefits		Other Retiree Benefits	
	December 31,			
(in millions)	2015	2014	2015	2014
Regulatory Pension Asset Included in Regulatory Assets	$115	$117	$5	$9
Accrued Benefit Liability Included in Accrued Employee Expenses	(1)	(1)	(2)	(2)
Accrued Benefit Liability Included in Pension and Other Retiree Benefits	(57)	(71)	(63)	(67)
Accumulated Other Comprehensive Loss (related to SERP)	5	5	—	—
Net Amount Recognized	$62	$50	$(60)	$(60)

OBLIGATIONS AND FUNDED STATUS

We measured the actuarial present values of all pension benefit obligations and other retiree benefit plans at December 31, 2015 and 2014. The table below includes all of TEP's plans. All plans have projected benefit obligations in excess of the fair value of plan assets for each period presented. The status of our pension benefit and other retiree benefit plans are summarized below:

	Pension Benefits		Other Retiree Benefits	
	Year Ended December 31,			
(in millions)	2015	2014	2015	2014
Change in Projected Benefit Obligation				
Benefit Obligation at Beginning of Year	$407	$330	$81	$74
Actuarial (Gain) Loss	(22)	67	(5)	5
Interest Cost	17	16	3	3
Service Cost	12	10	4	4
Benefits Paid	(20)	(16)	(5)	(5)
Projected Benefit Obligation at End of Year	394	407	78	81
Change in Plan Assets				
Fair Value of Plan Assets at Beginning of Year	335	307	12	10
Actual Return on Plan Assets	(3)	35	—	1
Benefits Paid	(20)	(16)	(5)	(5)
Employer Contributions [(1)]	24	9	6	6
Fair Value of Plan Assets at End of Year	336	335	13	12
Funded Status at End of Year	$(58)	$(72)	$(65)	$(69)

[(1)] In 2016, TEP expects to contribute $10 million to the pension plans.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Pension Benefits		Other Retiree Benefits	
	Year Ended December 31,			
(in millions)	2015	2014	2015	2014
Net Loss	$117	$118	$6	$11
Prior Service Cost (Benefit)	3	4	(1)	(2)

The accumulated benefit obligation aggregated for all pension plans is $355 million and $365 million at December 31, 2015 and 2014, respectively.

All three of our pension plans had accumulated benefit obligations in excess of plan assets at December 31, 2014. As a result of increases in discount rates and employer contributions, two of our plans had accumulated benefit obligations in excess of plan assets at December 31, 2015. The following table includes information for pension plans with accumulated benefit obligations in excess of pension plan assets:

	December 31,	
(in millions)	2015	2014
Accumulated Benefit Obligation	$188	$365
Fair Value of Plan Assets	169	335

Net periodic benefit plan cost includes the following components:

	Pension Benefits			Other Retiree Benefits		
	Year Ended December 31,					
(in millions)	2015	2014	2013	2015	2014	2013
Service Cost	$12	$10	$11	$4	$4	$3
Interest Cost	17	16	14	3	3	3
Expected Return on Plan Assets	(23)	(21)	(19)	(1)	(1)	(1)
Actuarial Loss Amortization	7	3	8	—	—	—
Net Periodic Benefit Cost	$13	$8	$14	$6	$6	$5

Approximately 20% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in income.

We measured service and interest costs for pension and other postretirement benefits utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. At the end of 2015, we changed our approach to determine the service and interest cost components of pension and other postretirement benefit expense. We elected to measure service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows beginning in 2016. TEP believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of our plan obligations nor the funded status. We accounted for this change as a change in accounting estimate, and accordingly, have accounted for it on a prospective basis.

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

	Pension Benefits					
	Regulatory Asset			AOCI		
(in millions)	2015	2014	2013	2015	2014	2013
Current Year Actuarial (Gain) Loss	$5	$49	$(42)	$—	$3	$(1)
Amortization of Actuarial Gain (Loss)	(7)	(3)	(8)	—	—	—
Total Recognized (Gain) Loss	$(2)	$46	$(50)	$—	$3	$(1)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Other Retiree Benefits Regulatory Asset		
(in millions)	2015	2014	2013
Current Year Actuarial (Gain) Loss	$(4)	$5	$(6)

For all pension plans, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. We expect to amortize an estimated $7 million net loss from pension regulatory assets and an estimated $1 million in prior service credit from other retiree benefit plan regulatory assets into net periodic benefit cost in 2016.

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

	Pension Benefits		Other Retiree Benefits	
	2015	2014	2015	2014
Discount Rate	4.5-4.6%	4.1-4.2%	4.2%	3.9%
Rate of Compensation Increase	3.0%	3.0%	N/A	N/A

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

	Pension Benefits			Other Retiree Benefits		
	2015	2014	2013	2015	2014	2013
Discount Rate	4.1%-4.2%	5.0%-5.1%	4.1%-4.1%	3.9%	4.7%	3.8%
Rate of Compensation Increase	3.0%	3.0%	3.0%	N/A	N/A	N/A
Expected Return on Plan Assets	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%

Net periodic benefit cost is subject to various assumptions and determinations, such as the discount rate, the rate of compensation increase, and the expected return on plan assets.

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

Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as net periodic benefit cost. The following table includes the assumed health care cost trend rates:

	December 31,	
	2015	2014
Next Year	7.6%	6.7%
Ultimate Rate Assumed	4.5%	4.5%
Year Ultimate Rate is Reached	2036	2027

Assumed health care cost trend rates significantly affect the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects on the December 31, 2015 amounts:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on Total Service and Interest Cost Components	$1	$1
Effect on Retiree Benefit Obligation	6	5

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

PENSION PLAN AND OTHER RETIREE BENEFIT ASSETS

Pension Assets

We calculate the fair value of plan assets on December 31, the measurement date. Pension plan asset allocations, by asset category, on the measurement date were as follows:

	2015		2014	
Asset Category				
Equity Securities	49	%	48	%
Fixed Income Securities	41	%	43	%
Real Estate	8	%	7	%
Other	2	%	2	%
Total	100	%	100	%

The following table sets forth the fair value measurements of pension plan assets by level within the fair value hierarchy:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
(in millions)	December 31, 2015			
Asset Category				
Cash Equivalents	$1	$—	$—	$1
Equity Securities:				
United States Large Cap	—	81	—	81
United States Small Cap	—	17	—	17
Non-United States	—	67	—	67
Fixed Income	—	137	—	137
Real Estate	—	8	18	26
Private Equity	—	—	7	7
Total	$1	$310	$25	$336
(in millions)	December 31, 2014			
Asset Category				
Cash Equivalents	$1	$—	$—	$1
Equity Securities:				
United States Large Cap	—	82	—	82
United States Small Cap	—	17	—	17
Non-United States	—	61	—	61
Fixed Income	—	143	—	143
Real Estate	—	8	16	24
Private Equity	—	—	7	7
Total	$1	$311	$23	$335

Level 1 cash equivalents are based on observable market prices and are comprised of the fair value of commercial paper, money market funds, and certificates of deposit.

Level 2 investments comprise amounts held in commingled equity funds, United States bond funds, and real estate funds. Valuations are based on active market quoted prices for assets held by each respective fund.

Level 3 real estate investments were valued using a real estate index value. The real estate index value was developed based on appraisals comprising 100% of real estate assets tracked by the index.

Level 3 private equity funds are classified as funds-of-funds. They are valued based on individual fund manager valuation models.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(in millions)	Private Equity	Real Estate	Total
Beginning Balance at January 1, 2014	$7	$14	$21
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	(1)	—	(1)
Ending Balance at December 31, 2014	7	16	23
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	(1)	—	(1)
Ending Balance at December 31, 2015	$7	$18	$25

Pension Plan Investments

Investment Goals

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

Risk Management

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

Relationship between Plan Assets and Benefit Obligations

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Target Allocation Percentages

The current target allocation percentages for the major asset categories of the plan as of December 31, 2015 follow. Each plan allows a variance of +/- 2% from these targets before funds are automatically rebalanced.

	TEP Plans	VEBA Trust
Cash/Treasury Bills	—%	2%
Equity Securities:		
United States Large Cap	24%	39%
United States Small Cap	5%	5%
Non-United States Developed	15%	7%
Non-United States Emerging	5%	9%
Fixed Income	42%	38%
Real Estate	8%	—%
Private Equity	1%	—%
Total	100%	100%

Pension Fund Descriptions

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

Other Retiree Benefit Assets

As of December 31, 2015, the fair value of VEBA trust assets was $13 million, of which $5 million were fixed income investments and $8 million were equities. As of December 31, 2014, the fair value of VEBA trust assets was $12 million, of which $4 million were fixed income investments and $8 million were equities. The VEBA trust assets are primarily Level 2. There are no Level 3 assets in the VEBA trust.

ESTIMATED FUTURE BENEFIT PAYMENTS

TEP expects the following benefit payments to be made by the defined benefit pension plans and other retiree benefit plan, which reflect future service, as appropriate.

(in millions)	2016	2017	2018	2019	2020	2021-2025
Pension Benefits	$17	$18	$19	$21	$22	$125
Other Retiree Benefits	5	5	5	6	6	33

DEFINED CONTRIBUTION PLAN

We offer a defined contribution savings plan to all eligible employees. The Internal Revenue Code identifies the plan as a qualified 401(k) plan. Participants direct the investment of contributions to certain funds in their account. We match part of a participant's contributions to the plan. TEP made matching contributions to the plan of $5 million in 2015, 2014, and 2013.

NOTE 9. SHARE-BASED COMPENSATION

2011 STOCK AND INCENTIVE PLAN

The Fortis acquisition of UNS Energy in 2014 resulted in accelerated vesting and expense recognition of all outstanding non-vested UNS Energy share-based awards issued under the UNS Energy 2011 Omnibus Stock and Incentive Plan (2011 Plan). The outstanding non-vested awards would otherwise have been recognized over remaining vesting periods through February 2017. TEP recognized approximately $2 million of expense in 2014 due to the accelerated vesting of the awards. TEP recorded total share-based compensation expense of $5 million for the year ended December 31, 2014 and $3 million for the year ended December 31, 2013. In August 2014, UNS Energy settled all outstanding share-based compensation awards related to the 2011 Plan in cash.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2015 SHARE UNIT PLAN

The Human Resources and Governance Committee (Committee) of UNS Energy, approved and UNS Energy's Board of Directors ratified the 2015 Share Unit Plan (Plan) effective as of January 1, 2015. Under the Plan, key employees, including executive officers of UNS Energy and its subsidiaries, may be granted long-term incentive awards of performance-based share units (PSUs) and time-based restricted share units (RSUs) annually. Each PSU and RSU granted will be valued based on one share of Fortis common stock converted to U.S. dollars. Fortis common stock is traded on the Toronto Stock Exchange. TEP’s share of the obligation and expense as a subsidiary of UNS Energy is allocated based on the Massachusetts Formula.

UNS Energy awarded 47,776 PSUs and 23,888 RSUs in 2015 that are payable on the third anniversary of the grant date. The awards are classified as liability awards based on the cash settlement feature. Liability awards are measured at their fair value at the end of each reporting period and will fluctuate based on the price of Fortis common stock as well as the level of achievement of the financial performance criteria. At December 31, 2015, TEP's allocated share of probable payout is $2 million.

TEP's allocated portion of the compensation expense is recognized in Operations and Maintenance on the Consolidated Statements of Income. Compensation expense associated with unvested PSUs and RSUs is recognized on a straight-line basis over the minimum required service period in an amount equal to the fair value on the measurement date or each reporting period. TEP recorded $1 million for the year ended December 31, 2015 based on its share of UNS Energy's compensation expense.

NOTE 10. SUPPLEMENTAL CASH FLOW INFORMATION

CASH TRANSACTIONS

	Year Ended December 31,		
(in millions)	2015	2014	2013
Interest, Net of Amounts Capitalized	$65	$83	$53
Income Taxes	—	—	—

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:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Accrued Capital Expenditures	$28	$29	$24
Net Cost of Removal of Interim Retirements [(1)]	1	12	25
Commitment to Purchase Capital Lease Interests	—	109	55
Capital Lease Obligations [(2)]	—	1	9
Proceeds from Issuance of Long-Term Debt Deposited in Trust	—	—	191
Asset Retirement Obligations [(3)]	3	4	8

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

(2) The non-cash change in capital lease obligations represents interest accrued for accounting purposes in excess of interest payments.

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

NOTE 11. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

We categorize our financial instruments into the three-level hierarchy based on inputs used to determine the fair value. Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in an active market. Level 2 inputs include quoted prices for similar assets or liabilities, quoted prices in non-active markets, and pricing models whose inputs are observable, directly or

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

indirectly. Level 3 inputs are unobservable and supported by little or no market activity. Transfers between levels are recorded at the end of a reporting period. There were no transfers between levels in the periods presented.

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS

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

	Level 1	Level 2	Level 3	Total
(in millions)	December 31, 2015			
Assets				
Cash Equivalents[1]	$33	$—	$—	$33
Restricted Cash[1]	4	—	—	4
Energy Derivative Contracts - Regulatory Recovery[2]	—	1	—	1
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	1	1
Total Assets	37	1	1	39
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(10)	(3)	(13)
Interest Rate Swap[3]	—	(3)	—	(3)
Total Liabilities	—	(13)	(3)	(16)
Net Total Assets (Liabilities)	$37	$(12)	$(2)	$23
(in millions)	December 31, 2014			
Assets				
Cash Equivalents[1]	$15	$—	$—	$15
Restricted Cash[1]	2	—	—	2
Energy Derivative Contracts - Regulatory Recovery[2]	—	—	2	2
Total Assets	17	—	2	19
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(9)	(9)	(18)
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	(1)	(1)
Energy Derivative Contracts - Cash Flow Hedge[2]	—	—	(1)	(1)
Interest Rate Swap[3]	—	(5)	—	(5)
Total Liabilities	—	(14)	(11)	(25)
Net Total Assets (Liabilities)	$17	$(14)	$(9)	$(6)

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

(2) Energy Contracts include gas swap agreements (Level 2), power options (Level 2), gas options (Level 3), forward power purchase and sales contracts (Level 3) entered into to reduce exposure to energy price risk, and, at December 31, 2014 a power sale option (Level 3). These contracts are included in Derivative Instruments on the Consolidated Balance Sheets. The valuation techniques are described below.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Gross Amount Recognized on the Balance Sheets	Gross Amount Not Offset on the Balance Sheets Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
(in millions)	December 31, 2015			
Derivative Assets				
Energy Derivative Contracts	$2	$1	$—	$1
Derivative Liabilities				
Energy Derivative Contracts	(13)	(1)	—	(12)
Interest Rate Swap	(3)	—	—	(3)
(in millions)	December 31, 2014			
Derivative Assets				
Energy Derivative Contracts	$2	$2	$—	$—
Derivative Liabilities				
Energy Derivative Contracts	(20)	(2)	—	(18)
Interest Rate Swap	(5)	—	—	(5)

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.

The December 31, 2014 valuation of our power sale option was a function of observable market variables, regional power and gas prices, as well as the ratio between the two, which represents the prevailing market heat rate.

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

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

Cash Flow Hedges

We can enter into interest rate swaps to mitigate the exposure to volatility in variable interest rates on debt. We have an interest rate swap agreement that expires January 2020. We also had a power purchase swap to hedge the cash flow risk associated with

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

a long-term power supply agreement which expired in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities are reported in the statement of comprehensive income. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $1 million. The realized losses from our cash flow hedges are shown in the following table:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Capital Lease Interest Expense	$2	$2	$2
Long-Term Debt Interest Expense	—	1	1
Purchased Power	1	1	1

As of December 31, 2015, the total notional amount of our interest rate swap was $29 million.

Energy Derivative Contracts - Regulatory Recovery

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

	Year Ended December 31,		
(in millions)	2015	2014	2013
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$6	$(18)	$—

Energy Derivative Contracts - No Regulatory Recovery

Forward contracts with long-term wholesale customers do not qualify for regulatory recovery. For these contracts that qualify as derivatives, we record unrealized gains and losses in the income statement, unless and until a normal purchase or normal sale election is made. In February 2015, TEP made a normal sale election for a three-year sales option contract entered into in December 2014. In June 2015, TEP entered into long-term power trading contracts that qualify as derivatives but do not qualify for regulatory recovery. The unrealized gains and losses on the long-term power trading contracts are recorded in the income statement, and 10% of any gains will be shared with ratepayers through the PPFAC, as realized.

Derivative Volumes

At December 31, 2015, we have energy contracts that will settle through the fourth quarter of 2018. The volumes associated with our energy contracts were as follows:

	December 31,	
	2015	2014
Power Contracts GWh	1,752	2,604
Gas Contracts GBtu	17,214	19,932

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 of Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input	
(in millions)	December 31, 2015					
Forward Power Contracts	Market approach	$1	$(2)	Market price per MWh	$19.20	$31.35
Gas Option Contracts	Option model	—	(1)	Market price per MMbtu	$2.17	$2.69
				Gas volatility	31.0%	58.3%
Level 3 Energy Contracts		$1	$(3)			
(in millions)	December 31, 2014					
Forward Power Contracts	Market approach	$1	$(6)	Market price per MWh	$22.35	$39.05
Power Sale Option	Market approach	1	(1)	Market price per MWh	$27.75	$44.94
				Market price per MMbtu	$2.88	$4.02
Gas Option Contracts	Option model	—	(4)	Market price per MMbtu	$2.72	$3.26
				Gas volatility	30.8%	53.3%
Level 3 Energy Contracts		$2	$(11)			

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 on the balance sheet 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 assets and liabilities classified as Level 3 in the fair value hierarchy:

	Year Ended December 31,	
(in millions)	2015	2014
Beginning of Period	$(9)	$(2)
Gains (Losses) Recorded to:[1]		
Net Regulatory Assets/Liabilities – Derivative Instruments	(4)	(8)
Electric Wholesale Sales	3	—
Settlements	8	1
End of Period	$(2)	$(9)

(1) Includes gains (losses) attributable to the change in unrealized gains/(losses) relating to assets (liabilities) still held at the end of the period of $(1) million and $(8) million for the years ended December 31, 2015, and 2014, respectively.

CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of non-performance by counterparties pursuant to the terms of their

contractual obligations. We enter into contracts for the physical delivery of energy and gas which contain remedies in the event of non-performance by the supply counterparties. In addition, volatile energy prices can create significant credit exposure from energy market receivables and subsequent measurement at fair value.
We have contractual agreements for energy procurement and hedging activities that contain certain provisions requiring each company to post collateral under certain circumstances. These circumstances include: exposures in excess of unsecured credit

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

limits; 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 December 31, 2015, 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 $20 million, compared with $27 million at December 31, 2014. At December 31, 2015, TEP had less than $1 million of LOCs as credit enhancements with its counterparties. If the credit risk-related contingent features were triggered on December 31, 2015, TEP would have been required to post an additional $20 million of collateral of which $8 million relates to outstanding net payable balances for settled positions.

FINANCIAL INSTRUMENTS NOT CARRIED AT FAIR VALUE

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

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

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

	Fair Value Hierarchy	Face Value		Fair Value	
		December 31,			
(in millions)		2015	2014	2015	2014
Liabilities					
Long-Term Debt, including Current Maturities	Level 2	$1,466	$1,375	$1,529	$1,457

NOTE 12. INCOME TAXES

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

	Year Ended December 31,		
(in millions)	2015	2014	2013
Federal Income Tax Expense at Statutory Rate	$70	$56	$52
State Income Tax Expense, Net of Federal Deduction	8	7	7
Federal/State Tax Credits	(8)	(5)	(2)
Allowance for Equity Funds Used During Construction	(1)	(2)	(1)
Deferred Tax Asset Valuation Allowance	1	—	2
Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset	—	—	(11)

Other	2	2	1
Total Federal and State Income Tax Expense	$72	$58	$48

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 Rate Order. The regulatory asset will be amortized as income tax expense as the qualifying assets are depreciated.

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

	Year Ended December 31,		
(in millions)	2015	2014	2013
Current Tax Expense (Benefit)			
Federal	$—	$(1)	$(8)
State	—	—	(2)
Total Current Tax Expense (Benefit)	—	(1)	(10)
Deferred Tax Expense (Benefit)			
Federal	66	54	47
Federal Investment Tax Credits	(6)	(4)	(1)
State	12	9	12
Total Deferred Tax Expense (Benefit)	72	59	58
Total Federal and State Income Tax Expense	$72	$58	$48

The significant components of deferred income tax assets and liabilities consist of the following:

	December 31,	
(in millions)	2015	2014
Gross Deferred Income Tax Assets		
Capital Lease Obligations	$27	$96
Net Operating Loss Carryforwards	156	187
Customer Advances and Contributions in Aid of Construction	20	19
Alternative Minimum Tax Credit	24	24
Accrued Postretirement Benefits	23	23
Emission Allowance Inventory	9	10
Investment Tax Credit Carryforward	32	31
Other	53	54
Total Gross Deferred Income Tax Assets	344	444
Deferred Tax Assets Valuation Allowance	(4)	(2)
Gross Deferred Income Tax Liabilities		
Plant, Net	(750)	(699)
Capital Lease Assets, Net	(12)	(74)
Pensions	(27)	(27)
PPFAC	—	(8)
Other	(19)	(24)
Total Gross Deferred Income Tax Liabilities	(808)	(832)
Net Deferred Income Tax Liabilities	$(468)	$(390)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP has recorded a $4 million valuation allowance against credit and loss carryforward deferred tax assets at December 31, 2015 and a $2 million valuation allowance against credit carryforward deferred tax assets at December 31, 2014. Management believes TEP will not produce sufficient taxable income to use all credit and loss carryforwards before they expire.

As of December 31, 2015, TEP had the following carryforward amounts:

(in millions)	Amount	Expiring Year
Federal Net Operating Loss	$430	2031-34
State Net Operating Loss	114	2016-34
State Credits	10	2016-30
Alternative Minimum Tax Credit	24	None
Investment Tax Credits	32	2032-35

Uncertain Tax Positions

A reconciliation of the beginning and ending balances of unrecognized tax benefits follows:

	December 31,	
(in millions)	2015	2014
Beginning of Period	$4	$2
Additions Based on Tax Positions Taken in the Current Year	1	2
End of Period	$5	$4

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million at December 31, 2015 and would not reduce income tax expense at December 31, 2014.

TEP recorded no interest expense during 2015 and 2014 related to uncertain tax positions. In addition, TEP had no interest payable and no penalties accrued at December 31, 2015 and 2014.

TEP has been audited by the IRS through tax year 2010. TEP is not currently under audit by any federal or state tax agencies. The balance in unrecognized tax benefits could change in the next 12 months as a result of IRS audits, but we are unable to determine the amount of change.

NOTE 13. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

Revenue from Contracts with Customers

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

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

Classification and Measurement of Financial Instruments

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

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

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

NOTE 14. QUARTERLY FINANCIAL DATA (UNAUDITED)

Our quarterly financial information is unaudited, but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility business is seasonal in nature. Peak sales periods for TEP generally occur during the summer. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
(in millions)	2015			
Operating Revenue	$273	$340	$409	$284
Operating Income	28	74	120	36
Net Income	9	38	69	12
(in millions)	2014			
Operating Revenue	$256	$322	$387	$305
Operating Income	32	80	85	34
Net Income	9	39	40	15

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

TEP's Chief Executive Officer and Chief Financial Officer supervised and participated in TEP's evaluation of its disclosure controls and procedures as such term is defined under Rule 13a – 15(e) or Rule 15d – 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 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.

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 2015 that has materially affected, or is reasonably likely to materially affect, TEP's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

All of the members of the TEP Board of Directors are executive officers and employees of TEP, a wholly owned subsidiary of UNS Energy.

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

The names and information concerning the members of the TEP Board of Directors are set forth below:

Name	Age	Served As Director Since	Business Experience
David G. Hutchens	49	2011	Mr. Hutchens has served as Chief Executive Officer of TEP since 2014; President of TEP since 2011; Executive Vice President of TEP in 2011; Vice President of TEP from 2007-2011. Mr. Hutchens joined TEP in 1995. Mr. Hutchens' extensive experience in the electric and gas utility business and his position as President and Chief Executive Officer provide him with intimate knowledge of TEP's operations and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEP Board.
Kevin P. Larson	59	2009	Mr. Larson has served as Senior Vice President and Chief Financial Officer of TEP since September 2005. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer. Mr. Larson is also a Chartered Financial Analyst. Mr. Larson's extensive experience in the electric and gas utility business and his position as Senior Vice President and Chief Financial Officer provide him with intimate knowledge of TEP's financial affairs and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEP Board.
Todd. C. Hixon	49	2015	Mr. Hixon has served as Vice President and General Counsel of TEP since May 2011. Mr. Hixon joined TEP’s legal department in 1998 and served in a variety of capacities, most recently serving as Associate General Counsel. Mr. Hixon's extensive experience in utility legal and regulatory matters and his position as Vice President and General Counsel provide him with intimate knowledge of TEP's legal and regulatory affairs and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEP Board.

Executive Officers

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

Name	Age	Position(s) Held	Executive Officer Since
David G. Hutchens	49	President and Chief Executive Officer	2007
Kevin P. Larson	59	Senior Vice President and Chief Financial Officer	1997
Kentton C. Grant	57	Vice President and Treasurer	2007
Susan M. Gray	43	Vice President, T&D Operations and Engineering	2015
Todd C. Hixon	49	Vice President and General Counsel	2011
Karen G. Kissinger	61	Vice President and Chief Compliance Officer	1991
Mark C. Mansfield	60	Vice President, Energy Resources	2012
Frank P. Marino	51	Vice President and Controller	2013
Thomas A. McKenna	67	Vice President, Energy Delivery	2007
Catherine E. Ries	56	Vice President, Customer and Human Resources	2007
Mary Jo Smith	58	Vice President, Public Policy	2015
Herlinda H. Kennedy	54	Corporate Secretary	2006

David G. Hutchens	Mr. Hutchens has served as Chief Executive Officer of TEP since 2014; President of TEP since 2011; Executive Vice President of TEP in 2011; Vice President of TEP from 2007-2011. Mr. Hutchens joined TEP in 1995.
Kevin P. Larson	Mr. Larson has served as Senior Vice President and Chief Financial Officer of TEP since September 2005. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer.
Kentton C. Grant	Mr. Grant was elected Treasurer in 2010 and has served as Vice President of TEP since January 2007. Mr. Grant joined TEP in 1995.
Susan Gray	Ms. Gray has served as Vice President of T&D Operations and Engineering since 2015. Ms. Gray joined TEP in 1994 as a student engineer, and has served in a variety of capacities since then, most recently serving as Senior Director of T&D.
Todd C. Hixon	Mr. Hixon has served as Vice President and General Counsel of TEP since May 2011. Mr. Hixon joined TEP's legal department in 1998 and served in a variety of capacities, most recently serving as Associate General Counsel.
Karen G. Kissinger	Ms. Kissinger has served as Vice President and Chief Compliance Officer of TEP since August 2013. Ms. Kissinger served as Vice President, Controller, and Chief Compliance Officer from 2001 to 2013. Ms. Kissinger joined TEP as Vice President and Controller in January 1991.
Mark C. Mansfield	Mr. Mansfield has served as Vice President, Energy Resources since 2012. He joined the company in 2008 as Senior Director of Generation.
Frank P. Marino	Mr. Marino has served as Vice President and Controller of TEP since August 2013. Mr. Marino joined TEP as Assistant Controller in January 2013. Prior to joining TEP, he served in various roles at the AES Corporation, a global power company. In 2012 he served as AES' Vice President for Business Demand and Outsourcing Management, and from 2007-2011 he served as Chief Financial Officer for two different business units.
Thomas A. McKenna	Mr. McKenna has served as Vice President, Energy Delivery since August 2013. Mr. McKenna was named Vice President, Engineering in January 2007. Mr. McKenna joined an affiliate of TEP in 1998. Mr. McKenna is retiring from TEP on May 1, 2016.
Catherine E. Ries	Ms. Ries has served as Vice President, Customer and Human Resources since August 2015. Prior to that she served as Vice President of Human Resources and Information Technology, since May 2011. Ms. Ries joined TEP as Vice President of Human Resources in June 2007.
Mary Jo Smith	Ms. Smith has served as Vice President of Public Policy since 2015. Ms. Smith joined TEP as Director of Investor Relations in 2003 and most recently served as Senior Director of Regulatory Services and Corporate Communications.
Herlinda H. Kennedy	Ms. Kennedy has served as Corporate Secretary of TEP since September 2006. Ms. Kennedy joined TEP in 1980 and was named assistant Corporate Secretary in 1999.

Code of Ethics

See Part I, Item 1. Business, SEC Reports Available on TEP's Website.

Audit and Risk Committee of the UNS Energy Board

The Audit and Risk Committee of the Board of Directors of UNS Energy was established for the purpose of overseeing the accounting and financial reporting process and audits of the financial statements of UNS Energy and its consolidated subsidiaries, including TEP.

The Audit and Risk Committee reviews current and projected financial results of operations, selects an independent registered public accounting firm to audit UNS Energy's and TEP's financial statements annually, reviews and discusses the scope of such audit, receives and reviews the audit reports and recommendations and transmits its recommendations to the UNS Energy Board of Directors. The Audit and Risk Committee of UNS Energy reviews UNS Energy's and TEP's accounting and internal control procedures with the internal audit department from time to time, makes recommendations to the board of UNS Energy for any changes deemed necessary in such procedures and

performs such other functions as delegated by the UNS Energy Board of Directors.
The following UNS Energy directors are members of the Audit and Risk Committee of UNS Energy's Board of Directors:

- Ramiro G. Peru, Chair
- Robert A. Elliott

- James P. Laurito
- Gregory A. Pivirotto
- Joaquin Ruiz

All Audit and Risk Committee members possess the level of financial literacy and accounting or related financial management expertise required by New York Stock Exchange (NYSE) rules. UNS Energy's Board of Directors has determined that, while each member of the Audit and Risk Committee has accounting and/or related financial management expertise, Mr. Ramiro Peru is an "audit committee financial expert" as that term is defined by applicable SEC regulations.

Human Resources and Governance Committee of the UNS Energy Board

TEP is a wholly owned subsidiary of UNS Energy. As described in Part III, Item 11 Executive Compensation below, the TEP Board of Directors does not have a Compensation Committee and does not make compensation-related decisions for the executive officers of TEP. Instead, the UNS Energy Board of Directors' Human Resources and Governance Committee makes compensation-related decisions, including the approval of the compensation plan described in Part III, Item 11 Executive Compensation.

The following UNS Energy directors are members of the Human Resources and Governance Committee of UNS Energy's Board of Directors:

- Louise L. Francesconi, Chair
- Lawrence J. Aldrich
- Robert A. Elliott
- Barry Perry

UNS Energy Directors

Due to the role of the Audit and Risk Committee and the Human Resources and Governance Committee of the UNS Energy Board of Directors described above, the following information is included with respect to the members of the UNS Energy Board of Directors (other than with respect to Mr. Hutchens, who is also a member of the Board of Directors of UNS Energy):

Name	Age	Served as Director Since	Business Experience
Lawrence J. Aldrich	63	2000	Partner, Newport Board Group, since 2014; Chairman and Executive Director, Arizona Business Coalition on Health, since 2011; President and Chief Executive Officer of University Physicians Healthcare (UPH), a healthcare organization, from 2009 to 2010; Senior Vice President/Corporate Operations and General Counsel for UPH from 2007 to 2008; President of Aldrich Capital Company, an acquisition, management and consulting firm, since 2007; Chief Operating Officer of The Critical Path Institute, a non-profit medical research company focusing in drug development, from 2005 to 2007. Mr. Aldrich's extensive experience in the areas of public relations/advertising, finance, legal, human resources, marketing, engineering, operations, government/regulatory, information technology, insurance/health care, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.

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Robert A. Elliott	60	2003	President and owner of Elliott Accounting, an accounting, tax, management and investment advisory services firm, since 1983; Chair of AAA of Arizona, a regional automotive and travel club, since 2014 and Director since 2007; Director and Corporate Secretary of Southern Arizona Community Bank, a banking institution, from 1998 to 2010; Television Analyst/Pre-game Show Co-host for Fox Sports Arizona from 1998 to 2009; Chairman of the Board of the Tucson Airport Authority, an airport operator/manager, from January 2006 to January 2007; President and Chairman of the Board of the National Basketball Retired Players Association from 2011-2013; Director of University of Arizona Foundation, a philanthropic organization, since 2011. Mr. Elliott’s extensive experience in the areas of accounting, audit, banking and corporate tax, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Louise L. Francesconi	63	2008	President of Raytheon Missile Systems, a defense electronics corporation, from 1997 until her retirement in 2008; Director of Stryker Corporation, a medical technology company, since July 2006; Chairman of the Board of Trustees for TMC Healthcare, a hospital, since 1999; Director of Global Solar Energy, Inc., a manufacturer of solar panels and other solar-related products, from 2008 to 2011. Ms. Francesconi’s extensive experience in the areas of accounting, public relations/advertising, finance, legal, human resources/benefits, marketing, engineering, operations, audit, government/regulatory, information technology and insurance/healthcare, and her significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
James P. Laurito	59	2014	President and CEO of Central Hudson Gas & Electric Company since November 1, 2014. Mr. Laurito joined Central Hudson as President in November 2009. Prior to that, he served as President of both New York State Electric and Gas Corporation and Rochester Gas & Electric Corporation from 2003 until 2009. Mr. Laurito's extensive experience in the electric and gas utility business contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Barry Perry	51	2014	President and CEO of Fortis since December 31, 2014. Prior to his current position at Fortis, Mr. Perry served as Vice President, Finance and CFO of Fortis since 2004. Mr. Perry joined the Fortis organization in 2000 as VP, Finance and CFO of Newfoundland Power. Previously, he held the position of VP, Treasurer with a global forest products company and Corporate Controller with a large crude oil refinery. Mr. Perry's extensive experience in the electric and gas utility business contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Ramiro G. Peru	60	2008	Executive Vice President and Chief Financial Officer of Phelps Dodge Corporation, a mining corporation, from 2004 until his retirement in 2007; Senior Vice President and Chief Financial Officer of Phelps Dodge Corporation from 1999 to 2004; Director of Anthem, Inc. (formerly

WellPoint, Inc.), a health benefits company, since 2004; Board of Directors, Fiesta Bowl, since 2012; Director of SM Energy Company, 2014 - 2015.

Mr. Peru's extensive experience in the areas of accounting, corporate communications, finance, legal, human resources/benefits, audit, government/regulatory, corporate tax, information technology, insurance/health care and environmental contributes to the diverse knowledge, skills and qualifications of the UNS Energy Board.

Gregory A. Pivirotto	63	2008	President, Chief Executive Officer and Director of University Medical Center Corporation, in Tucson, from 1994 until his retirement in 2010; Adjunct Professor at the University of Arizona College of Law since 2013; certified public accountant since 1978; Director of Arizona Hospital & Healthcare Association, a trade association providing advocacy, education and service to hospitals and other healthcare organizations, from 1997 to 2005; Director of Tucson Airport Authority, an airport operator/manager, from 2008 to January 2014; Member of the Advisory Board of Harris Bank Arizona from 2010 to 2013; Director of the Donor Network of Arizona from 1993 to 2006 and since 2012. Mr. Pivirotto's extensive experience in the areas of accounting, public relations/advertising, finance, legal, human resources/benefits, marketing, operations, audit, government/regulatory, banking, corporate tax, information technology and insurance/healthcare, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Joaquin Ruiz	64	2005	Professor of Geosciences, University of Arizona, an educational institution, since 1983; Dean, College of Science, University of Arizona, since 2000; Executive Dean of the University of Arizona College of Letters, Arts and Science since 2009 and Vice President for Strategy and Innovation since 2012. Mr. Ruiz's extensive experience in the areas of renewables and environmental, public relations/advertising, human resources/benefits, operations, government/regulatory, information technology, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

This section describes TEP's overall executive compensation policies and practices and specifically analyzes the total compensation for the following executive officers, referred to as the Named Executives:

- David G. Hutchens, President and Chief Executive Officer;
- Kevin P. Larson, Senior Vice President and Chief Financial Officer;
- Karen G. Kissinger, Vice President and Chief Compliance Officer;
- Todd C. Hixon, Vice President and General Counsel; and
- Kentton C. Grant, Vice President and Treasurer

COMPENSATION PHILOSOPHY

Compensation Committee

TEP is a wholly owned subsidiary of UNS Energy (itself a wholly owned, indirect subsidiary of Fortis). The TEP Board of Directors does not have a Compensation Committee and does not make compensation-related decisions for the executive officers of TEP. The same individuals serve as executive officers of both UNS Energy and TEP. The UNS Energy Board of Directors Human Resources and Governance Committee makes all compensation decisions for all such executive officers, including the design of the 2015 executive compensation program, and also approves this disclosure, among other responsibilities. Any references to a Compensation Committee in this section refer to the UNS Energy Human Resources and Governance Committee.

TEP Compensation as a Component of UNS Energy Total Compensation

The Compensation Committee designs its programs to compensate UNS Energy executive officers for services to UNS Energy and all UNS Energy subsidiaries, including TEP. The amounts shown in this section represent the Named Executives' compensation allocated to TEP and its subsidiaries only, which, in 2015 amounts to 80.90% of the Named Executives total compensation for service provided to UNS Energy and its subsidiaries. The percentage allocated to TEP is obtained using the Massachusetts formula, an industry-wide accepted method of allocating common costs to affiliated entities based on an equal weighting of payroll costs, plant/tangible assets and total revenues. References to the Company refer to UNS Energy and include all UNS Energy subsidiaries. The Performance Enhancement Plan (PEP) includes target goals attributable to TEP, UNS Electric, and UNS Gas.

Objectives of the Compensation Program

The Compensation Committee has established a balanced total compensation program that ensures that a significant part of executive officer compensation is performance-based. Corporate goals are designed to focus executive officers and all non-union employees on successful execution of the Company's strategy and annual operating plan.

The Company's executive officer compensation policies and decisions have the following objectives:

1. Attracting, motivating and retaining highly-skilled executives;
2. Linking the payment of compensation to the achievement of critical short- and long-term financial and strategic objectives; providing safe, reliable and economically available electric and gas service; and aligning performance objectives of management with those of its other employees by using similar performance measures for both groups;
3. Balancing risk and reward to align the interests of management with those of the Company's stakeholders and encouraging management to think and act like owners, taking into account the interests of the public that the Company serves;
4. Maximizing the financial efficiency of the compensation program to avoid unnecessary tax, accounting and cash flow costs; and
5. Encouraging management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance "best practices."

Summary of 2015 Executive Officer Compensation Program

Compensation Component	Key Features	Purpose
Base Salary	Increases considered on an annual basis to remain near the median of the Company's peer group (as described in Elements of Compensation - Base Salary, below) Intended to constitute a sufficient component of total compensation to discourage inappropriate risk-taking	Provide a fixed amount of cash compensation to the Company's Named Executives
Short-term Incentive Compensation (Performance Enhancement Program or PEP)	Incentive plans are structured identically for executive and non-executive employees and across business units/functions, uniting all non-union employees in the achievement of common goals All incentive plans are capped at 150% of target, protecting against the possibility that executives would try to maximize bonuses by taking short-term actions not supportive of long-term objectives. Must achieve at least the threshold level of net income to receive payment above 50% of target for other performance measures; this cap limits non-financial goal payout if the financial goals are not met	Motivate and reward achieving or exceeding the Company's short-term performance goals, reinforcing pay-for-performance Focus entire Company on key customer, operational and financial objectives
Long-Term Incentive Compensation (LTI or equity-based compensation)	LTI compensation is delivered in a combination of performance share units (PSUs) and restricted share units (RSUs) Ultimate value earned from the LTI program is based on both absolute and relative shareholder value and longer-term operating performance PSUs represent 67% of the target award with 50% of the shares earned based on achievement of cumulative net income goals and 50% of the shares earned based on achievement of Fortis's TSR relative to an industry peer group over a three-year period RSUs represent 33% of the target awards, and cliff vest on the 3rd anniversary of grant	Opportunities for ownership and financial reward in support of the Company’s longer-term financial goals and stock price growth; also supports retention objective Provide a link between compensation and long-term shareholder interests as reflected in changes in Fortis stock price

The Compensation Committee considers decisions regarding each component of pay in the context of each executive officer’s total compensation. For example, if the Compensation Committee increases an executive officer’s base salary, it also considers the resultant impact on short- and long-term performance-based incentive compensation and compares total compensation levels to competitive practice. See Compensation Analysis, below. The Compensation Committee does not directly consider the value of previous equity awards in setting current year total compensation opportunities, but does review the value of outstanding equity awards to assess the degree to which such awards support the Company's performance motivation, retention, and shareholder alignment objectives.

Each of these components is described in more detail below and in the narrative and footnotes to the supporting tables. The following sections highlight how the above objectives are reflected in the Company's compensation program.

Attracting, Retaining and Motivating Executives

To attract, retain and motivate highly-skilled employees, the Company provides the Named Executives with compensation packages that are competitive with those offered by other electric and gas utility companies of comparable size and complexity and/or electric and gas utility companies thought to be competitors for executives.

The Compensation Committee generally targets total direct compensation for the Named Executives to be, on average, at the median of selected comparable companies identified below under the Compensation Analysis section. Under this approach, newly promoted executives and those new to their role may be placed below the median to reflect their limited experience and evolving skill set. Similarly, executives with longer tenure and therefore an above-market skill set, or those executives who are sustained high performers over time and are most critical to the Company’s long-term success, may be placed above the median. The Company believes that this strategy enables it to successfully hire, motivate and retain talented executives while ensuring a reasonable overall compensation cost structure relative to its peers.

In addition to providing competitive direct compensation opportunities, the Company also provides certain indirect compensation and benefits programs that are intended to assist in attracting and retaining high quality executives. These programs include pension and retirement programs and are described in more detail below and in the narratives that accompany the tables that follow this section.

Linking Compensation to Performance

The Company’s compensation program seeks to link the actual compensation earned by the Named Executives to their performance and that of the Company and Fortis. To ensure that the executive officers are held accountable for achieving the Company’s financial, operational and strategic objectives and for creating Fortis shareholder value, the Company believes that the percentage of pay at risk should increase with the level of responsibility within the Company. The target amounts of performance-based pay programs comprise approximately 45% to 70% of the total direct compensation opportunity for the Named Executives. Of the performance-based compensation, approximately 30-50% is short-term and 50-70% is long-term. Placing a greater emphasis on long-term performance-based compensation encourages executive officers to focus on the long-term impact of their actions. Non-variable compensation, such as benefits and perquisites, is de-emphasized in the total compensation program to reinforce the linkage between compensation and performance.

Balancing Risk and Reward to Align the Interests of the Company’s Named Executives with Stakeholders

The Company's compensation program seeks to align the interests of the Named Executives with those of the Company’s key stakeholders, including Fortis shareholders, customers, the community and employees. The Company uses the short-term incentive compensation component to focus the Named Executives on the importance of providing safe and reliable customer service, creating a safe work environment for employees and improving financial performance by linking their short-term cash incentive compensation to achievement of these objectives. The Company uses an equity-based compensation component of its compensation package to align the interests of the Named Executives with those of the Fortis shareholders. The Company's compensation strategy mitigates risk by emphasizing long-term compensation and financial performance measures correlated with shareholder value. UNS Energy believes that equity-based compensation, together with the three-year vesting of share-based awards, result in compensation programs that do not encourage excessive risk-taking by management relating to the Company’s business and operations, and increase executive officer accountability in the performance of the Company. In addition, the Compensation Committee has the ability to reduce short-term incentive compensation award payouts, in its sole discretion, based upon factors other than Company performance measures. In considering the design alternatives, the Compensation Committee continually evaluates the potential for unintended consequences of its compensation program.

Maximizing the Financial Efficiency of the Program

In structuring the total compensation package for the Named Executives, the Compensation Committee evaluates the accounting cost, cash flow implications and tax deductibility of compensation to mitigate financial inefficiencies to the greatest extent possible. For instance, as part of this process, the Compensation Committee evaluates whether compensation costs are fixed or variable and places a heavier weighting on variable pay elements to calibrate expense with the achievement of operating performance objectives.

Adhering to Corporate Governance “Best Practices”

The Compensation Committee continually seeks to evaluate the executive officer compensation program in light of corporate governance “best practices.” For example, the short-term and long-term incentive compensation programs include a clawback provision, and the Change in Control Agreements do not contain an excise tax gross-up provision, all of which are discussed in more detail below.

The Compensation Committee also reviews tally sheets and wealth accumulation analyses, which are designed to assist the Compensation Committee in evaluating the reasonableness of the compensation provided to Named Executives.

Compensation Analysis

To provide a foundation for the executive officer compensation program, the Company periodically benchmarks its Named Executives' compensation levels and practices against a peer group of companies intended to represent the Company's competitors for business and talent. The peer group, which is reviewed periodically and approved by the Compensation Committee, includes the 12 utility companies named below that are comparable to UNS Energy in size, as measured by annual revenues and market capitalization (the Peer Group). As of November 2013, the date when the most recent benchmarking analysis was performed, UNS Energy's revenues and number of employees approximate the median of the Peer Group; total assets and market capitalization were between the 25th percentile and the median; net income is below the 25th percentile.

2015 Peer Group

ALLETE, Inc.	NorthWestern Corp.
Avista Corp.	NV Energy, Inc.
Cleco Corp.	PNM Resources Inc.
El Paso Electric Co.	Portland General Electric Co.
Great Plains Energy, Inc.	UIL Holdings Corp.
IDACORP Inc.	Westar Energy Inc.

ELEMENTS OF COMPENSATION

Base Salary

The Company uses base salary to provide each Named Executive a set amount of money during the year with the expectation that he or she will perform his or her responsibilities to the best of his or her ability and in the best interests of the Company. The Company believes that competitive base salaries are necessary to attract and retain executives critical to achieving its business goals. In general, Named Executives' base salaries are targeted to the median of the Peer Group described above. However, individual salaries can and do vary from the Peer Group median data based on such factors as: (i) the competitive environment for Named Executives; and (ii) incumbent responsibilities, experience, skills and performance relative to similarly situated executive officers within the Company. Named Executives' salaries range from below the 25th percentile to the median of the Peer Group at the time the last benchmarking review was conducted.

Increases to Named Executives' base salaries are considered annually by the Compensation Committee. In approving base salary increases for Named Executives other than the CEO, the Compensation Committee also considers the CEO's recommendations.

In February 2015, the Compensation Committee approved 2% base salary increases for the Named Executives, which were consistent with salary increases as a percent of salary for other non-union Company employees. Base salary as a percentage of total compensation for the Named Executives ranged from approximately 30-55% of target total direct compensation. Additional information is provided in the Summary Compensation Table below.

Short-Term Incentive Compensation (Cash Awards)

The Company's short-term incentive compensation consists of cash awards under the Performance Enhancement Plan ("PEP"), which links a significant portion of the Named Executives' annual compensation to the Company's annual financial and operational performance.

Each year, before the end of the first quarter, the Compensation Committee establishes performance objectives that must be met in whole or in part before the Company pays PEP awards. The key performance objectives are tailored to drive behavior that supports the Company's strategy of delivering safe, reliable service and value to customers and a fair return to shareholders over time. The Compensation Committee generally attempts to align the target opportunity for each Named Executive, stated as a percentage of base salary, with the median rate for equivalent positions at the Peer Group companies. In 2015, the target short -term incentive opportunity for the Named Executives ranged from 40% to 80% of base salary, depending upon the Named Executive's responsibilities (i.e., the greater the responsibility, the more pay at risk). The Company's Named Executives' target incentive opportunities as a percent of base salary were near the Peer Group median at the time the last benchmarking review was conducted. As described more fully below, the actual amounts paid depend on the achievement of specified performance objectives and could range from 50% of the target award upon achievement of threshold performance to 150% of the target award upon achievement of exceptional performance.

Financial and Operating Performance Objectives-2015

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2015, the objectives were: (i) net income; (ii) O&M cost containment; and (iii) excellent operations and safe work environment. The Compensation Committee selected the goals and individual weightings for the 2015 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence. This use of balanced financial and operational metrics encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders.

The program design includes a 50% maximum payment cap if the Net Income goal does not achieve at least Threshold attainment. This ensures sufficient income to fund the program and reiterates the importance of the Net Income Goal. Finally, the Board of Directors has discretion to adjust any payout.

The financial and other metrics for the Company's 2015 Short-Term Incentive Compensation program were:

- Financial – 60%, Comprising of:
  - Net Income – 40%
  - O&M Cost Containment – 20%
- Excellent Operations and Safe Work Environment – 40%

In developing the PEP performance targets, Company management compiles relevant data such as Company historic performance and industry benchmarks and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The 2015 financial performance objectives were:

	Threshold	Target	Exceptional
Net Income (in millions) results interpolated	$139.6	$150.1	$160.6
O&M Long-Term Increase final results interpolated	3.0%	2.0%	1.5%

The 2015 operational and safety performance objectives were:

	Threshold	Target	Exceptional
Excellent Operations			
Equivalent Availability Factor ("EAF") Generation Reliability – Summer	92.43%	93.42%	≥94.42%
System Average Interruption Duration Index ("SAIDI") Transmission/Distribution Reliability	78-90	57-77	< 57
Customer Satisfaction - Improve Residential Customer Satisfaction Score Measured by JD Power	640 - 649	650 - 669	≥670
Safe Work Environment			
OSHA Rate (Employee Safety Incident Rate)	1.70	1.50	< 1.00

2015 PEP Results

Summary:

Overall, the 2015 results produced a total weighted performance for all goals of 113.2% of target performance, as summarized in Table A below. The Compensation Committee approved an overall PEP payout of 113.2% of target awards.

Table A: Summary of 2015 PEP Results

Goal	Weighting of Goal (A)	Percentage of Target Performance Achieved (B) [1]	Payout Percentage (A x B)
Net Income	40%	108%	43.2%
Safe Work Environment	10%	50%	5.0%
O&M Cost Containment	20%	150%	30.0%
Excellent Operations	30%	Various	35.0%
	100%		113.2%

[1] Additional details provided below.

Net Income Goal:

In 2015, the Company achieved $151.8 million of net income, which was above target performance (results are interpolated). Table B, below, reflects the net income goal, which ranged from $139.6 million (threshold) to $160.6 million (exceptional), and the corresponding payout levels, which ranged from 50% to 150% of the target award, as well as the actual net income achieved for 2015. Net income must have been more than $139.6 million to produce a payout. The achievement of $151.8 million in net income resulted in a payout level of 108.1% of the target amount for the Net Income performance objective.

Table B: Net Income

	Final Result: $151.8										
(in millions)	Range										
	$139.6	$141.7	$143.8	$145.9	$148.0	$150.1	$152.2	$154.3	$156.4	$158.5	$160.6
Payout % of Target	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
	á					á					á
	Threshold					Target				Exceptional	
					Actual $151.8						

O&M Cost Containment Goal:

Prior to 2015, the O&M cost containment goal focused on achieving a targeted current year O&M spending level. In 2015 the goal was changed to reflect a longer term view of O&M by focusing on results of the 2016 budget (set by management in mid-year 2015) as a percentage increase over the 2015 base O&M budget. The lower increase of year over year budget estimates represents better performance. This O&M goal is meant to trigger longer-term thinking on how the Company's leadership might structurally change its business and processes, using proven process improvement methods, to focus on moving the business forward while containing costs. In 2016, the program design will include a monitoring of performance to the established 2016 budget. Table C, below, reflects the O&M cost containment goal, which ranged from 3.0% increase (threshold) to 1.5% increase (exceptional), and the corresponding payout levels, which ranged from 50% to 150% of the target award (results are interpolated). In 2015 the Company achieved a 2016 O&M budget decrease of 0.5%, which was exceptional performance, and resulted in a payout level of 150% for that performance objective.

Table C: O & M Long Term Increase

	Final Result: 1.5%										
(in millions)	Range										
	3.0%	2.8%	2.6%	2.4%	2.2%	2.0%	1.9%	1.8%	1.7%	1.6%	1.5%
Payout % of Target	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
	á					á					á
	Threshold					Target				Exceptional	
										Actual (0.5)%	

Excellent Operations Goals:

- Equivalent Availability Factor ("EAF"): The reliability of the Company's plant performance during the peak summer demand season is critical to its customers and due to approved rate design, to financial performance; therefore, a Summer EAF goal is used in measuring the reliability of the Company's generation fleet.

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- System Average Interruption Duration Index ("SAIDI"): This reliability measure in the Company's Transmission and Distribution business area is a good outage duration performance measure, because it tracks the length or duration of outages across all customers, giving the Company a focus on reducing the outage time a customer experiences.
- Customer Satisfaction: This reliability metric is measured by the JD Power Customer Satisfaction survey. Improving the Company's interactions with customers is critical to the outcome of this goal.

Safe Work Environment Goal:

- Safety: The Company's safety measure tracks the OSHA Recordable Incident Rate, which is a good indicator of a company's safety efforts. Continued focus on safety initiative components (leadership, employee involvement, and regulatory compliance) is a priority for the Company.

Table D, below, reflects the final achievement at the various levels of performance for the Excellent Operations and Safe Work Environment goals. According to the guidelines set by the Compensation Committee, the achievement of these goals yielded a result of 40% for this combination of performance objectives.

Table D: Excellent Operations/Safe Work Environment Goals

	Weight	Actual Result	Final Value	Totals
Excellent Operations (30% Weighting)				
Equivalent Availability Factor ("EAF") Generation Reliability – Summer	10%	Exceptional	15%	
System Average Interruption Duration Index ("SAIDI") Transmission/Distribution Reliability	10%	Target	10%	
Customer Satisfaction - Improve Residential Customer Satisfaction Score Measured by JD Power	10%	Target	10%	
Subtotal: Excellent Operations				35.0%
Safe Work Environment (10% Weighting)				
OSHA Rate (Employee Safety Measure)	10%	Threshold	5%	
Subtotal: Safe Work Environment				5.0%
Total Percentage for Excellent Operations and Safe Work Environment				40.0%

The Company's internal audit department verified that the reported results for the 2015 PEP goals were accurate and reported its findings to the Compensation Committee.

The amounts of the 2015 PEP awards paid to each of the Named Executives are listed in the Summary Compensation Table below.

Long-Term Incentive Compensation (Equity Based Awards)

UNS Energy believes that equity-based awards align the interests of executive officers with the interests of Fortis' shareholders and fosters the growth and success of the business of the Company and Fortis in accordance with the vision of both the Company and Fortis. In addition, the vesting provisions applicable to the awards encourages a focus on long-term operating performance, linking compensation expense to the achievement of multi-year financial results and helping to retain executive officers.

In 2015, the Compensation Committee approved the adoption of a new long-term incentive plan under which certain key employees, including executive officers, may be granted long-term incentive awards of performance-based share units ("PSUs") and time-based restricted share units ("RSUs"). Executive officers receive a cash payment for each PSU and RSU that is payable and vested pursuant to the plan. The payment is based on the market price of one share of common stock of Fortis on the applicable payment or vesting date, which is then converted to U.S. dollars in accordance with the plan. All prior long-term incentive awards that predate the current plan were paid out in 2014 as a result of the acquisition of UNS by Fortis.

The long-term incentive ("LTI") opportunity for each Named Executive is based on a percentage of salary. The 2015 LTI multiples are 150% for Mr. Hutchens, 100% for Mr. Larson, and 40% for Ms. Kissinger and Messrs. Hixon and Grant. The dollar values of the Named Executives' long-term incentives are generally in the 25th percentile to median range of the Peer Group. Under the design of the compensation plan for 2015, two-thirds of the award opportunity was granted as performance

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share units and one-third was to be granted as restricted share units that vest 100% on the third anniversary of grant to support retention objectives as well as succession planning initiatives.

2015 Performance Share Units

Performance share unit awards granted in 2015 will be distributed, along with dividend equivalents (to the extent that the performance share units become earned and vested), at the end of the three-year payment criteria period ending in 2017, based on the following equally-weighted payment criteria:

•TSR Payment Criteria

The first financial performance criteria is the TSR of Fortis stock relative to the TSR of a predefined peer group (the "LTI Peer Group") shown below for the same period.

TSR Percentile Rank	Payout as a Percent of Target Award
75th percentile and above	75.0%
50th percentile	50.0%
30th percentile	25.0%
Below 30th percentile	0.0%

Intermediate payouts determined by interpolation.

LTI Peer Group

AGL Resources	NiSource Inc.
Alliant Energy	Northeast Utilities
Ameren Corp.	OGE Energy Corp.
Atmos Energy Corp.	Pinnacle West Capital Corp.
Canadian Utilities, Ltd.	PPL Corp.
CenterPoint Energy, Inc.	Public Svc Enterprise Group
CMS Energy Corp.	SCANA Corp.
DTE Energy Co.	Sempra Energy
Emera, Inc.	TECO Energy Inc.
Great Plains Energy	UGI Corp.
LTI Peer Group	Westar Energy, Inc.
MDU Resources Group Inc.	Wisconsin Energy Corp.
New Jersey Resources, Corp.	Xcel Energy Inc.

•Cumulative Net Income Payment Criteria

The second financial payment criteria is cumulative net income (CNI) determined in accordance with GAAP and compared to a target cumulative net income of UNS Energy based on an assessment of external and management forecasts for the same period.

Degree of Performance Attainment (in millions)	Three-Year Cumulative Net Income	Payout as a Percent of Target Award Earned	
Exceptional	$527	75.0	%
Target	457	50.0	%
Threshold	387	25.0	%
Less than Threshold	< 387	0.0	%

Intermediate payouts determined by interpolation.

Equity Grant Timing and Practice

During the first quarter following the close of a fiscal year, the Compensation Committee approves and grants the long-term incentive awards for that year, including the type of equity to be granted, as well as the size of the awards for Named

Executives. In determining the type and aggregate size of awards to be provided, as well as the performance metrics that apply, the Compensation Committee considers the strategic goals of the Company and Fortis, trends in corporate governance, accounting impact, tax deductibility, cash flow considerations, and the impact on Fortis's earnings per share. The timing of awards was not coordinated with the release of material non-public information.

CLAWBACK PROVISION FOR VARIABLE COMPENSATION

Consistent with current “best practices,” short- and long-term incentive compensation awards are subject to clawback provisions. The clawback provision may apply to the income derived from the financial component of the PEP and the performance share units in the event of a restatement of financial results that, in the view of the Compensation Committee, results from fraud or intentional misconduct. The Compensation Committee has discretion to determine to whom the clawback will apply and the amount subject to clawback, if such repayment is determined to be necessary.

ELEMENTS OF POST EMPLOYMENT COMPENSATION

Termination and Change in Control

Prior to the Company's acquisition by Fortis, the Compensation Committee had determined that it was in the Company’s and shareholders’ best interest to enter into change in control agreements with its executive officers in order to attract highly qualified executives and to retain those executives through any future challenges that might arise. All of these agreements were designed to be consistent with contemporary “best practices,” such as double trigger severance payments and equity vesting and no excise tax gross-ups. These various agreements are still in effect and are discussed in detail in Potential Payments Upon Termination or Change in Control, below.

Generally speaking, the Company does not enter into or extend employment agreements with current officers and instead only uses employment agreements when needed in recruiting a new officer. The Company currently has no employment agreements in place.

UNS Energy also maintains a severance pay plan for all of the Company’s non-union employees, including its Named Executives, which continues the Company’s historical practice of providing severance pay in certain termination situations without a change in control and provides consistency in that practice.

Retirement and Other Benefits

The Company offers retirement and other core benefits to its employees, including the Named Executives, in order to provide them with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction. The basic retirement and other core benefits are the same for all employees and Named Executives and include medical and dental coverage, disability insurance and life insurance. In addition, the TEP 401(k) Plan (the “401(k) Plan”) and the TEP Salaried Employees Retirement Plan (the “Retirement Plan”) provide a reasonable level of retirement income reflecting employees’ careers with the Company. All employees, including Named Executives, participate in these plans; the cost of these benefits (other than the Retirement Plan) is partially borne by the employee, including each Named Executive. In addition, the Company provides all of its officers with an optional executive physical annually.

In addition to the basic retirement plans, described above, to the extent that any executive officer’s retirement benefit exceeds Internal Revenue Code (Code) limits for amounts that can be paid through a qualified plan, the Company also offers non-qualified retirement plans, including the TEP Excess Benefit Plan (Excess Benefit Plan) and the Management and Directors Deferred Compensation Plan (DCP). These plans provide only the difference between the calculated benefits and Code limits. These benefits are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and retention value of the executive officer compensation program and are consistent with similar competitive compensation benefits made available to executives in the industry. UNS Energy believes the DCP and the Excess Benefit Plan assist with the Company’s attraction and retention objectives. The DCP provides an industry-competitive and tax-efficient benefit to the executive officers. The DCP is not funded by the Company; DCP participants are unsecured creditors of the Company with respect to their DCP plan accounts. The Excess Benefit Plan provides the retirement benefits to executive officers that would have been provided under the Retirement Plan if the Code limitations did not apply. For more information on retirement and certain related benefits, see Pension Benefits and Non-Qualified Deferred Compensation, below.

ROLE OF EXECUTIVES IN ESTABLISHING COMPENSATION

Certain executive officers, including the CEO, the CFO, the General Counsel and the Vice President of Customer and Human Resources, routinely attend regular sessions of Compensation Committee meetings; however, they are excused for executive sessions when their compensation is discussed and/or determined. The CEO makes recommendations to the Compensation Committee with respect to changes in compensation for senior executive officer positions (other than the CEO) and payouts under the annual incentive plan. The CEO also makes suggestions to the Compensation Committee regarding the design of incentive plans and other programs in which senior management participates.

The CFO provides information regarding short-term and long-term compensation targets, as well as updates on the progress of short- and long-term objectives. Additional Company personnel with expertise in and responsibility for compensation and benefits provide information regarding executive officer and director compensation, including cash compensation, equity awards, pensions, deferred compensation and other related information.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis section required by Item 402(b) of SEC Regulation S-K and contained in this annual report. Based on such review and discussions, the Compensation Committee recommended to the Board of Directors of TEP that the Compensation Discussion and Analysis section be included in TEP's annual report on Form 10-K for the year ended December 31, 2015.

Respectfully submitted,

THE HUMAN RESOURCES AND GOVERNANCE COMMITTEE OF UNS ENERGY CORPORATION

Louise L. Francesconi, Chair
Lawrence J. Aldrich
Robert A. Elliott
Barry Perry

SUMMARY COMPENSATION TABLE – 2015[1]

The following table sets forth summary compensation information for the years ended December 31, 2013, 2014, and 2015 for the Company's Named Executives:

Name and Principal Position	Year	Salary	Share Awards[2]	Non-Equity Incentive Plan Compensation[3]	Change in Pension Value and Non-Qualified Deferred Compensation Earnings[4]	All Other Compensation[5][6]	Total
David G. Hutchens	2015	446,942	632,590	432,815	393,142	9,647	1,915,136
President and Chief	2014	397,962	417,359	377,827	555,358	2,529,306	4,277,812
Executive Officer	2013	306,482	432,998	198,513	105,379	14,209	1,057,580
Kevin P. Larson	2015	297,995	280,509	169,081	—	9,647	757,232
Senior Vice	2014	289,922	286,845	158,639	259,605	4,122,921	5,117,932
President and Chief Financial Officer	2013	279,435	327,989	142,107	46,725	12,574	808,831
Todd C. Hixon	2015	231,135	85,736	111,642	32,676	9,647	470,836
Vice President and General Counsel	2014	226,742	86,054	96,072	242,704	460,900	1,112,472
Karen G. Kissinger	2015	221,580	83,223	100,316	36,250	9,647	451,016
Vice President and	2014	219,094	86,054	95,088	325,958	2,272,033	2,998,227
Chief Compliance Officer	2013	216,627	252,798	107,659	—	10,147	587,230
Kentton C. Grant Vice President and Treasurer	2015	212,349	78,884	100,316	87,403	7,645	486,597

(1) The amounts included in the Summary Compensation Table represent only the amounts paid by UNS for services to TEP and its subsidiaries and do not include amounts paid by UNS for services to others. For 2015 services, 80.90% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries. For 2014 services, 80.46% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries. For 2013 services, 79.7% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries.

(2) The amounts included in the Share Awards column reflect 80.90% of the grant date fair value calculated in accordance with FASB ASC Topic 718 for restricted share units and performance share units granted in each of the years reported, excluding the effect of forfeitures. Half of the performance share unit awards had a grant date fair value, based on a Monte Carlo simulation, of $36.28 per share. These awards are based on Fortis's Shareholder Return relative to the Peer Group TSR for the three year performance period ended December 31, 2017. The remaining half had a grant date fair value, based on the grant date closing price, of $33.47 per share based on cumulative net income for the performance period ended December 31, 2017. The restricted share units had a grant date fair value, based on the grant date closing price, of $33.47 per share. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621. The restricted share units vest on the third anniversary of grant over the vesting period. In the case of performance share units, the amounts in the column reflect the grant date fair value assuming the probable outcome of the performance conditions. The 2015 amounts attributable to Restricted Share Units and Performance Share Units are shown on the following table:

	Restricted Share Units	Performance Share Units	Total
David G. Hutchens	224,979	407,611	632,590
Kevin P. Larson	99,762	180,747	280,509
Todd C. Hixon	30,492	55,244	85,736

Karen G. Kissinger	29,598	53,625	83,223
Kentton C. Grant	28,055	50,829	78,884

For the 2015 performance share grant, if the maximum level of performance is achieved and using [the fair market value of a share of Company common stock on the grant date ($36.28)], then the value of the payouts would be: $703,283 for David G. Hutchens, $311,855 for Kevin P. Larson, $95,317 for Todd C. Hixon, $92,524 for Karen G. Kissinger, and $87,699 for Kentton C. Grant.

(3) The 2015 PEP awards included in this column were paid in the first quarter of 2016 to each of the Named Executives.

(4) Any increase in the present value of the accrued benefit in the Retirement Plan and Excess Benefit Plan is reported in this column. All named executives experienced an increase in the present value of their respective accrued pension benefits during 2015. The present value of accumulated benefits payable is reflected in Pension Benefits, below. UNS Energy does not pay "above market" interest on non-qualified deferred compensation; therefore, this column reflects change in pension value only. See Non-qualified Deferred Compensation, below.

(5) The amounts in the All Other Compensation for 2015 column contain only Qualified 401 (k) Plan Matching Contributions.

(6) The amounts in the All Other Compensation column for 2014 include payments in exchange for stock awards canceled in connection with the acquisition of UNS Energy by Fortis in 2014.

GRANTS OF PLAN-BASED AWARDS – 2015

The following table sets forth information regarding plan-based awards by UNS to the Company's Named Executives in 2015 on account of services to TEP and its subsidiaries. As described above, 80.90% of the amount paid by UNS on account of services in 2015 is allocable to services to TEP and its subsidiaries. The compensation plans under which the grants in the following table were made are generally described in Compensation Discussion and Analysis, above and include the PEP, which provides for non-equity (cash) performance awards, and the 2015 Share Unit Plan, which provides for equity-based performance awards including restricted share units and performance share units.

	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards[1]			Estimated Future Payouts Under Equity Incentive Plan Awards (#) [2]			All Other Stock Awards: Number of Shares of Stock or Units (#) [3]	Grant Date Fair Value of Stock and Option Awards[4]
Name		Threshold	Target	Maximum	Threshold	Target	Maximum		
DAVID H. HUTCHENS									
PEP	1/1/2015	$179,986	$359,973	$539,959					
Performance Share Units	1/1/2015				6,721	13,442	20,164		$407,611
Restricted Share Units	1/1/2015							6,721	224,979
KEVIN P. LARSON									
PEP	1/1/2015	74,837	149,675	224,512					
Performance Share Units	1/1/2015				2,980	5,961	8,941		180,747
Restricted Share Units	1/1/2015							2,980	99,762
TODD C. HIXON									
PEP	1/1/2015	45,766	91,531	137,297					
Performance Share Units	1/1/2015				911	1,822	2,733		55,244
Restricted Share Units	1/1/2015							911	30,492
KAREN G. KISSINGER									
PEP	1/1/2015	44,417	88,835	133,253					
	1/1/2015				884	1,768	2,653		53,625

Performance Share Units									
Restricted Share Units	1/1/2015							884	29,598
KENTTON C. GRANT									
PEP	1/1/2015	43,686	87,372	131,058					
Performance Share Units	1/1/2015				838	1,676	2,514		50,829
Restricted Share Units	1/1/2015							838	28,055

(1) The amounts shown in this column reflect the range of payouts (50%-150% of the target award) for 2015 performance under the PEP, as described in Compensation Discussion and Analysis - Short-Term Incentive Compensation, above. These amounts are based on the

individual's current salary and position. The amount of cash incentive actually paid under the PEP for 2015 is reflected in the Summary Compensation Table above.

(2) The amounts shown in this column reflect the range (50%-150% of the target award) of payouts in the form of performance share units targeted for 2015-2017 performance under the 2015 Share Unit Plan for long-term incentive compensation, as described in the "Long-Term Incentive Compensation" section of the CD&A, above.

The target 2015 LTI multiples, as a percentage of base salary, are 150% for Mr. Hutchens, 100% for Mr. Larson, and 40% each for Ms. Kissinger and for Messrs. Hixon and Grant. Accordingly, each Named Executive received an LTIP target award of performance share units and restricted share units the total value of which was equal to the executive's base salary multiplied by the applicable multiple (e.g., 100% for CFO), divided by the grant date fair market value of a share of Fortis's common stock ($33.47), rounded down to the nearest 1 share. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621. For example, the CFO's 2015 base salary attributable to TEP (and LTIP target award) was $299,349, divided by $33.47, and rounded down to the nearest 1 share, resulted in an LTIP target award of 5,961 performance share units and 2,980 restricted share units.

The 2015 awards of performance share units will be paid in cash at the end of the performance period depending on the Company's performance relative to the two performance criteria described in Compensation Discussion and Analysis, above. The two performance criteria operate independently; a Named Executive may receive a payment on account of one of the criteria without regard to performance on the other criteria.

(3) The amounts shown in this column represent the number of time-based restricted share units that were granted in 2015 under the 2015 Share Unit Plan and will be paid in cash at the end of the vesting period.

(4) The amounts included in this column reflect 80.90% of the grant date fair value calculated in accordance with FASB ASC Topic 718 for restricted share units and performance share units granted in each of the years reported, excluding the effect of forfeitures. Half of the performance share unit awards had a grant date fair value, based on a Monte Carlo simulation, of $36.28 per share. These awards are based on Fortis's Shareholder Return relative to the Peer Group TSR for the three year performance period ended December 31, 2017. The remaining half had a grant date fair value, based on the grant date closing price, of $33.47 per share based on cumulative net income for the performance period ended December 31, 2017. The restricted share units had a grant date fair value, based on the grant date closing price, of $33.47 per share. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621. The restricted share units vest on the third anniversary of grant over the vesting period. In the case of performance share units, the amounts in the column reflect the grant date fair value assuming the probable outcome of the performance conditions. For more information about these awards, please refer to footnote 1 of the Summary Compensation Table and Compensation Discussion and Analysis, above.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END - 2015

	Stock Based Awards				
	Grant Date	Number of Shares or Units of Stock That Have Not Vested(1) (#)	Market Value of Number of Shares or Units of Stock That Have Not Vested (2) ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (3) (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (4) ($)
David G. Hutchens	1/1/2015	6,721	$218,176	13,442	$436,352
Kevin P. Larson	1/1/2015	2,980	96,745	5,961	193,490
Todd C. Hixon	1/1/2015	911	29,570	1,822	59,140
Karen G. Kissinger	1/1/2015	884	28,703	1,768	57,406
Kentton C. Grant	1/1/2015	838	27,206	1,676	54,413

(1) Number of time-based restricted share units that remain unvested as of December 31, 2015. Restricted share units vest on the third anniversary of the grant date, subject to continued service with the Company through that date.

(2) The market value of restricted share units and performance share units was calculated by multiplying the number of restricted share units outstanding or the number of performance share units (as determined in accordance with the Securities and Exchange Commission, or SEC, rules and footnote 5 below), as applicable, by $32.46 which was the share price as of 12/31/15. The share prices listed in this footnote are converted from Canadian Dollars (CAD) based on the Wall Street Journal currency exchange rate on the grant date (12/31/14) as required in the Share Unit Plan document which was 1.1621.

(3) Performance share units vest, if at all, after three years based on the achievement of performance of the cumulative goals over the applicable three-year period. The performance goals are described in the CD&A.

(4) The amounts for the 2015 performance share unit awards are shown at the target level based on the results for the first year of the 2015-2017 performance period.

OPTION EXERCISES AND STOCK VESTED

There were no stock options exercised or stock or share awards vested during the year ended December 31, 2015.

PENSION BENEFITS

The following table shows 80.90% of the present value of accumulated benefits payable to each of the Named Executives, including the number of years of service credited to each such Named Executive, under each of the Retirement Plan and the Excess Benefit Plan determined using interest rate and mortality rate assumptions used in the Company's financial statements. See Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and the Retirement and Other Benefits, above for information regarding the Retirement Plan and the Excess Benefit Plan.

	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year
David G. Hutchens	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	20.50	$ 763,775	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	20.50	1,192,238	—
Kevin P. Larson	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	30.83	1,272,805	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	30.83	1,366,778	—
Karen G. Kissinger	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	25	1,283,649	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	25	662,945	—
Todd C. Hixon	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	17.58	495,203	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	17.58	194,627	—
Kentton C. Grant	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	20.08	725,334	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	20.08	293,561	—

(1) The Retirement Plan is intended to meet the requirements of a qualified benefit plan for Code purposes and is funded by the Company and made available to all eligible employees. The Retirement Plan provides an annual income upon retirement based on the following formula:

1.6% x years of service (up to 25 years) x final average pay

Final average pay is calculated as the average of basic monthly earnings on the first of the month following the employee's birthday during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement. Basic monthly earnings means the monthly base salary prior to any reduction for contributions to a Code section 401(k) plan, but excluding overtime pay, bonuses or other compensation. Years of service are based on years and months of employment. A Retirement Plan participant vests in his or her retirement benefit after five years of service. The maximum benefit available under the Retirement Plan is an annual income of 40% of final average pay (as defined above). Plan compensation for purposes of determining final average pay is limited by compensation limits under Code Section 401(a)(17). For 2015, the limit was $265,000 in annual income.

Employees are eligible to retire early with an unreduced pension benefit if (i) the combination of their age and years of service equals or exceeds 85, or (ii) they are age 62 and have completed 10 years of service. Employees are also eligible for early retirement with a reduced pension benefit at age 55 with at least 10 years of service. The reduction at age 55 with 10 years of service is 42.6% and continues to be reduced at a lesser amount up to age 62, at which point there is no reduction. All optional forms of the benefit are actuarially equivalent. Messrs. Larson and Grant and Ms. Kissinger are currently eligible for early retirement.

(2) The Retirement Plan is subject to Code limitations on the amount of compensation that can be taken into account and on the amount of benefits that can be provided. The Excess Benefit Plan provides the retirement benefits to executive officers that would have been provided under the Retirement Plan if the Code limitations did not apply. The Excess Benefit Plan retirement benefit is calculated generally using the same pension formula as the Retirement Plan formula but with some modifications. Compensation for purposes of the Excess Benefit Plan is determined without regard to Code limits on compensation and by including voluntary salary reductions to the DCP and any annual incentive payment received under the PEP. The retirement benefit payable from the Excess Benefit Plan is reduced by the benefit payable to that person from the Retirement Plan. Vesting occurs after five years of service. Benefits are payable in a lump sum or annuity, at the participant's election. Messrs. Larson and Grant and Ms. Kissinger are currently eligible for early retirement.

(3) In preparing the aggregate increase in actuarial value of the above plans, the following assumptions and methods were used:

Measurements were made as of Tucson Electric Power Company's ASC 715 measurement date of December 31, 2015.

December 31, 2015 calculations were done using the spot rates underlying the Rate:Link 60-90 Yield Curve as of December 31, 2015 and RP-2014 mortality table, projecting mortality generationally at Scale MP-2015, with the following adjustments:

•The RP-2014 mortality table was adjusted to back out MP-2014 experience to 2006, then add back in MP-2015 through 2015.

•The MP-2015 projection scale was adjusted so that the ultimate rate of 1% at age 85 was reduced to 0.75%.

•The MP-2015 projection scale was further adjusted to reduce the convergence period to 15 years, rather than 20.

No pre-retirement mortality was assumed. For measurements at December 31, 2014, a discount rate of 4.10% and RP-2000 Female with generational projection using scale BB Female for females and RP-2000 Male with generational projection using scale BB Male for males, and both with no pre-retirement mortality were used for the Salaried and Excess Plans. This discount rate reflects rates as of December 31, 2015.

All participants were assumed to elect a 10 year Certain and Life benefit at the earliest age at which they are projected to be eligible for unreduced benefits.

NON-QUALIFIED DEFERRED COMPENSATION

UNS Energy sponsors the DCP for directors, executive officers and certain other employees of UNS Energy. Under the DCP, employee participants are allowed to defer on a pre-tax basis up to 100% of base salary and cash bonuses, and non-employee director participants are allowed to defer up to 100% of their cash compensation. The deferred amounts are valued daily as if invested in one or more of a number of investment funds, including UNS Energy share units, each of which may appreciate or depreciate in value over time. The choice of investment funds is determined by the individual participant. The amounts shown in the table below represent 80.90% of the total amounts, to reflect the portion allocable to TEP and its subsidiaries.

	Executive Contributions in Last Fiscal Year (1)	Aggregate Earnings in Last Fiscal Year (2)	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year End (3)
David G. Hutchens	—	—	—	—
Kevin P. Larson	—	8	—	54,372
Todd C. Hixon	—	—	—	—
Karen G. Kissinger	—	19	—	122,451
Kentton C. Grant	42,470	11	—	83,181

(1) Represents contributions to the DCP by the Named Executives during the year. The amounts shown, if any, are included in the salary column of the Summary Compensation Table, above.

(2) Represents the total market based earnings (losses) for the year on all deferred compensation under the DCP based on the investment returns associated with the investment choices made by the Named Executive. Amounts in this column are not included in the Summary Compensation Table.

(3) The aggregate balance includes compensation that was previously earned and reported in the Summary Compensation Table for 2013 and 2014 (if any) as follows: Mr. Larson—$8,817 and Ms. Kissinger—$1,287. Benefits under the plan will be distributed on the first to occur of the following events: separation from service, disability or death, in the form of either a lump sum or installment payments. The following table shows the deemed investment options available under the DCP and the annual rate of return for the calendar year ended December 31, 2015.

Name of Fund	Rate of Return	Name of Fund	Rate of Return
Fidelity Retirement Money Market	0.02%	Fidelity Spartan Us Equity Index	1.35%
Fidelity Intermediate Bond	0.68%	Fidelity Growth Company	7.94%
Janus Flexible Bond	0.09%	Fidelity Low Price Stock	(0.45)%
Fidelity Asset Manager	(0.44)%	Janus Worldwide	(2.30)%
Fidelity Equity-Income	(3.41)%	T. Rowe Price Blue Chip Growth	11.15%
Fidelity Managed Income	1.17%	Fidelity Diversified International K	3.24%
RS Value Y	(5.99)%	Franklin Utilities A	(7.38)%
American Beacon Small Cap Value Instl	(5.04)%	Allianz NFJ International Value Instl	(13.15)%
Fidelity Small Cap Stock	2.40%		

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

In order to ensure that the Company is able to retain its Named Executives, the Compensation Committee has determined that it is in the best interest of the Company and its shareholders to enter into change in control agreements with those Named Executives, as well as to maintain a severance pay plan for all of the Company’s non-union employees, including the Named Executives.

Change in Control Agreements

Each of our current executive officers, including our named executive officers who are currently employed by the Company, is party to a change in control agreement with UNS Energy entered into prior to the acquisition by Fortis. Under the change in control agreements, the executive officer will be entitled to receive change in control benefits if he or she incurs a separation from service due to the Company’s termination of his or her employment without “Cause” or due to the executive officer’s termination of employment with the Company for “Good Reason” during the six-month period prior to the occurrence of a Change in Control and if the executive officer’s separation from service is effected in contemplation of such Change in Control. The executive officer also will be entitled to receive these benefits if he or she incurs a separation from service due to the Company’s termination of his or her employment without Cause or due to the executive officer’s termination of employment for Good Reason during the 24-month period following the occurrence of a Change in Control.

A Change in Control is defined as: (i) the acquisition of beneficial ownership of 40% of the common stock of UNS Energy; (ii) certain changes in the Board; (iii) the closing of certain mergers or consolidations; or (iv) certain transfers of the assets of UNS Energy. Notwithstanding the foregoing, a Change in Control will not be deemed to have occurred until: any required regulatory approval, including any final non-appealable regulatory order, has been obtained; and the transaction that would otherwise be considered a Change in Control closes.

A Change in Control with UNS Energy occurred on August 15, 2014, the time of the acquisition of UNS Energy by Fortis. The protection period ends on August 13, 2016. Since there was a Change in Control, if a qualifying separation occurs on or before August 13, 2016, then the executive officer will be entitled to severance benefits in the form of: (i) a single lump sum payment in an amount equal to two (for Mr. Hutchens), one and one-half (for Mr. Larson) or one (for Ms. Kissinger and Messrs. Hixon and Grant) times the greater of (a) the executive officer’s annualized base salary as of the date of the executive officer’s separation from service, or (b) the executive officer’s annualized base salary in effect immediately prior to any material diminution in the executive officer’s base salary following execution of the change in control agreement; (ii) a single lump sum cash payment in an amount equal to two (for Mr. Hutchens), one and one-half (for Mr. Larson) or one (for Ms. Kissinger and Messrs. Hixon and Grant) times the average payment to which the executive officer was entitled pursuant to the short-term incentive compensation plan for the three calendar years immediately preceding the calendar year in which the executive officer's separation from service occurs or, if that data is not available, the executive officer's target payment under the short-term incentive compensation plan; (iii) a single lump sum cash payment in an amount equal to a prorated portion of the actual payment to which the executive officer would have been entitled under the short-term incentive compensation plan for the calendar year in which the executive officer's separation from service occurs; and (iv) a single lump sum cash payment in the amount of the payment, if any, to which the executive officer is entitled under the short-term incentive compensation plan (based on the executive officer's actual performance) for the year prior to the year in which the executive officer's separation from service occurs, to the extent not already paid to the executive officer. "Good reason" is defined under these agreements to mean: (i) a material, adverse diminution in the executive officer's authority, duties or responsibilities; (ii) a material change in the geographic location at which the executive officer must primarily perform services; (iii) a material diminution in the executive officer's base salary provided that such diminution is not a result of a generally applicable reduction in the base salary of all officers of the Company in an amount that does not exceed 10%; or (iv) any action or inaction that constitutes a material breach of the agreement by the Company. "Cause" is defined under these agreements to mean: (i) the willful failure of the executive officer to perform any of the executive officer's duties for the Company which continues after the Company has given the executive written notice describing the failure and an opportunity to cure the failure; (ii) a material violation of Company policy; (iii) any act of fraud or dishonesty; (iv) the executive officer's gross misconduct in the performance of the executive officer's duties that results in material economic harm to the Company; (v) the executive officer's conviction of, or plea of guilty or no contest, to a felony; or (vi) the executive officer's material breach of the executive officer's employment agreement with the Company, if any.

The executive officer would also be entitled to continue to participate in TEP's health, life, disability or other insurance benefit plans for a period expiring on the earlier of (a) 24 months (for Mr. Hutchens), 18 months (for Mr. Larson), or 12 months (for Ms. Kissinger and Messrs. Hixon and Grant) following the executive officer's separation from service, or in some cases for the respective period following the Change in Control event, or (b) the day on which the executive officer becomes eligible to receive any substantially similar benefits, on a benefit-by-benefit basis, under any plan or program of any successor employer. In the event the executive officer elected a high deductible health care plan pursuant to which TEP has agreed to make contributions to the executive officer's health savings account, then TEP will pay to the executive officer a single lump sum cash payment in an amount equal to the contributions that TEP would have made to the executive officer's health savings account during the respective benefit continuation period described above had the executive officer not incurred the separation from service.

The Change in Control Agreements provide that the executive officer shall be employed by UNS Energy or one of its subsidiaries or affiliates, in a position comparable to the current position, with base compensation and benefits at least equal to the then-current compensation and benefits, for an employment period of two years after a Change in Control (subject to earlier termination for cause or the executive officer's termination without good reason).

The Change in Control Agreements also contain a number of material conditions or obligations applicable to the receipt of payments or benefits, which require the executive officer to: (i) continue to abide by the terms and provisions of the Company's policies that protect various forms of confidential information and intellectual property; (ii) refrain from consulting with, engaging in or acting as an advisor to another company about business that competes with the Company; (iii) refrain from soliciting business for or in connection with any competing business (a) from any individual or entity that obtained products or services from the Company at any time during the executive officer's employment with the Company or (b) from any individual or entity that was solicited by the executive officer on behalf of the Company; and (iv) refrain from soliciting employees of the Company who would have the skills and knowledge necessary to enable or assist efforts by the executive officer to engage in a competing business. Item (i) referred to in this paragraph contains no durational limit, nor do the Change in Control Agreements include any provision providing for waiver of a breach of item (i). Items (ii) through (iv) referred to in this paragraph are effective for a period of one year following the date of the executive officer's termination. Breach of items (ii) through (iv) is waived if the Company materially defaults on any of its obligations under the Change in Control Agreements.

No excise tax gross-ups are provided. Rather, severance payments to executives are cut back to the safe harbor limit if the reduction results in the executive receiving a greater after-tax benefit than if the excise tax were paid by the executive on the excess parachute payments; otherwise, all payments would be paid and the executive would pay the excise tax.

All long-term incentive awards contain a double trigger vesting provision, which provides for accelerated vesting only if outstanding awards are not assumed by an acquirer and also provide for accelerated vesting upon a qualifying termination following a Change in Control. This double trigger vesting provision applies to future awards and/or if the

Named Executive is terminated without cause within 24 months of a Change in Control. The double trigger, which is viewed as a corporate governance “best practice,” ensures that the Named Executives do not receive accelerated benefits unless they are adversely affected by the Change in Control.

On May 2, 2014, Mr. Hutchens was appointed CEO of UNS Energy and TEP in addition to his duties as President and Chief Operating Officer of each company. Incident to the appointment, Mr. Hutchens's Change in Control agreement was modified to increase the benefits to which he will be entitled if his employment is terminated by UNS Energy without cause or by Mr.

Hutchens with good reason following a change in control and to provide that he was not entitled to terminate employment and receive the benefits provided by his Change in Control Agreement solely for the reason that he would no longer be CEO of a publicly traded company as a result of the acquisition of UNS Energy by Fortis.
On November 13, 2014, UNS Energy and Mr. Larson entered into a retention bonus agreement, the terms of which were approved by the UNS Energy Human Resources and Governance Committee. The retention bonus agreement amends Mr. Larson's change in control agreement to provide that changes in Mr. Larson's responsibilities that occurred as a result of the acquisition of UNS Energy by Fortis, or that may occur for succession purposes based on a future mutually-agreed transition process, shall not constitute good reason for Mr. Larson to terminate his employment and receive benefits under the change in control agreement.

Severance Pay Plan

In addition, the Company has a severance pay plan (Severance Plan) for all of the Company's non-union employees, including its Named Executives, which provides for severance benefits in the event of a qualifying termination, which means a termination without cause without a change in control. Cause for termination under the Severance Plan means: (i) the willful failure of the employee to perform any of the employee's duties for the employer which continues after the employer has given the participant written notice describing the failure and an opportunity to cure the failure; (ii) a material violation of Company policy; (iii) any act of fraud or dishonesty; (iv) willful failure to report to work for three days or to report to work on the agreed-upon date after a scheduled leave; or (v) willfully engaging in conduct that is demonstrably and materially injurious to the Company or any affiliate, monetarily or otherwise, including acts of fraud, misappropriation, violence or embezzlement for personal gain at the expense of the Company or any affiliate, conviction of (or plea of guilty or no contest or its equivalent to) a felony, or a misdemeanor involving immoral acts.

In the event of a qualifying termination, the Named Executive would be entitled to: (i) a cash severance payment equal to a multiple of base salary (two times for Mr. Hutchens, one and one-half times for Mr. Larson, and one time for Ms. Kissinger and Messrs. Hixon and Grant; (ii) continued subsidy of the premiums for COBRA medical, dental and vision coverage at the same rate as that paid by the Company prior to the separation from service for a period of the lesser of (a) 12 months, or (b) the date when the Named Executive becomes eligible for comparable benefits offered by a subsequent employer; and (iii) a portion of the amount to which the Named Executive would have been entitled under the Company's PEP or any successor plan, based on the executive's target payment for the year in which the executive's separation from service occurs, had the Named Executive not incurred a separation from service.
Receipt of benefits under the Severance Plan is contingent upon execution of a release of claims against the Company and subject to compliance with restrictive covenants, including perpetual confidentiality and non-disparagement provisions, and non-compete and non-solicitation requirements effective for the applicable severance period (two years for Mr. Hutchens, one and one-half years for Mr. Larson, and one year for Ms. Kissinger and Messrs. Hixon and Grant). Duplication of benefits provided under the Severance Plan is not permitted, and benefits payable under the Severance Plan cease in the event the Named Executive becomes eligible for change in control severance benefits or if the Named Executive has an employment agreement that provides for severance benefits.

In the event a Named Executive becomes eligible to receive severance benefits under the Severance Plan and has elected a health care option pursuant to which the Company has agreed to make pre-tax contributions to the Named Executive's Health Savings Account, then the Company will pay the Named Executive an amount equal to the contributions the Company would have made to the Named Executive's health savings account during the twelve-month period immediately following the Named Executive's separation from service, plus a tax allowance in an amount equal to the federal, state and local taxes imposed on the Named Executive with respect to such contributions and with respect to the tax allowance. While as a general matter the Company does not provide tax gross-ups for severance arrangements or other benefits, it was deemed appropriate in this very limited circumstance because: (i) this particular type of benefit would be provided pre-tax, if the individual were still employed; (ii) the amounts in question are exceptionally small; and (iii) this treatment is available to all unclassified employees, not just the Named Executives, who become entitled to severance benefits under the Severance Plan and participate in the type of health care option described in the paragraph above.

Other than the agreements described above, UNS Energy has not entered into any severance agreements or employment agreements with any Named Executives.

The following table and summary set forth potential payments payable to the Named Executives upon termination of employment or a Change in Control assuming their employment was terminated on December 31, 2015.

	If Retirement or Voluntary Termination Occurs (1)	If "Change In Control" and Qualifying Termination Occurs(2)	If Death or Disability Occurs(3)	If "Non-Change In Control" Termination Occurs(4)
David G. Hutchens	$—	$2,428,415	$—	$2,428,415
Kevin P. Larson	—	1,108,825	—	1,108,825
Todd C. Hixon	—	495,409	—	430,778
Karen G. Kissinger	—	512,354	—	512,354
Kentton C. Grant		475,837		475,837

(1) In the event of retirement or voluntary termination, each of the Named Executives would be entitled to receive vested and accrued benefits payable from the Retirement Plan and the Excess Benefit Plan, but no form or amount of any such payment would be increased or otherwise enhanced nor would vesting be accelerated with respect to such plans. In addition, no accelerated vesting of options, restricted share units or performance share units would occur. Retirement Plan and Excess Benefit Plan information for the Named Executives is set forth in the Pension Benefits Table above.

(2) The amounts shown represent the following:

	Cash	Prorated Non-equity Incentive Award	Restricted Share Units	Performance Share Units	Medical Benefits	Total
David G. Hutchens	$1,380,088	$359,973	$218,176	$436,352	$33,826	$2,428,415
Kevin P. Larson	666,826	149,675	96,745	193,490	2,089	1,108,825
Todd C. Hixon	309,539	91,531	29,570	59,140	5,629	495,409
Karen G. Kissinger	318,060	88,835	28,703	57,406	19,350	512,354
Kentton C. Grant	294,529	87,372	27,206	54,413	12,317	475,837

Amounts shown in the column headed Prorated Non-equity Incentive Award above represent the total "target" PEP award for 2015.

(3) In the event of death, the Named Executive's survivor would be entitled to receive a survivor annuity from the Retirement Plan and Excess Benefit Plan. The amount payable to the survivor would be less than the amount that would otherwise have been payable to the Named Executive had the Named Executive survived and received retirement benefits under the Retirement Plan and Excess Benefit Plan. There would be no enhancements as to form, amount or vesting of such benefits in the event of a Named Executive's death.

(4) This column reflects the amounts payable to the Named Executives in the event of an involuntary termination without cause or a resignation for good reason, as of December 31, 2015, under the Severance Plan. The amounts shown represent the following:

	Cash	Pro-Rated Non-equity Incentive Award	Restricted Share Units	Performance Share Units	Medical Benefits	Total
David G. Hutchens	$1,380,088	$359,973	$218,176	$436,352	$33,826	$2,428,415
Kevin P. Larson	666,826	149,675	96,745	193,490	2,089	1,108,825
Todd C. Hixon	244,908	91,531	29,570	59,140	5,629	430,778
Karen G. Kissinger	318,060	88,835	28,703	57,406	19,350	512,354
Kentton C. Grant	294,529	87,372	27,206	54,413	12,317	475,837

Director Compensation

All TEP directors are also named executive officers of TEP and received no additional compensation for services as a director. All of their compensation is reflected in the Summary Compensation Table, above.

Compensation Committee Interlocks and Insider Participation

All members of the UNS Energy Human Resources and Governance Committee during fiscal year 2015 were independent directors, except for Mr. Perry, who is an executive officer of Fortis. No Human Resources and Governance Committee member had any relationship requiring disclosure under Transactions with Related Persons, in Part III, Item 13. Certain Relationships and Related Transactions and Director Independence, below. During fiscal year 2015, none of the Company's executive officers served on the Human Resources and Governance Committee or the Board of Directors of another entity whose executive officer(s) served on UNS Energy's Human Resources and Governance Committee, any other board committee, or the Board of Directors of UNS Energy or TEP as a whole.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

All of the outstanding shares of common stock, no par value, of TEP are held by UNS Energy, which is an indirect, wholly owned subsidiary of Fortis.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Director Independence

TEP's directors are not independent since they are executive officers of TEP and UNS Energy. There are no standing committees of the Board of Directors of TEP.

As described in Part III, Item 10. Directors, Executive Officers and Corporate Governance, above, the Audit and Risk Committee of the UNS Energy Board of Directors is responsible for overseeing the accounting and financial reporting process and audits of the financial statements of UNS Energy and its consolidated subsidiaries, including TEP.

As described in Part III, Item 11, Executive Compensation, above, the Human Resources and Governance Committee of the UNS Energy Board of Directors is responsible for overseeing the executive compensation policies and practices of UNS Energy and its consolidated subsidiaries, including TEP.

The Board of Directors of UNS Energy has adopted Director Independence Standards that comply with New York Stock Exchange (NYSE) rules for determining independence, among other things, in order to determine eligibility to serve on the Audit and Risk Committee and the Human Resources and Governance Committee of UNS Energy. Neither UNS Energy nor TEP has any securities listed on the NYSE or any other national securities exchange or inter-dealer quotation system requiring that directors or committee members be independent but, in approving the acquisition of UNS Energy by Fortis, the ACC required that a majority of the members of the UNS Energy Board of Directors be independent. The written charters of the UNS Energy Audit and Risk Committee and Human Resources and Governance Committee each require that a majority of the members of each such committee meet both UNS Energy's Director Independence Standards and independence standards of the NYSE. The UNS Energy Director Independence Standards are available on TEP's website at www.tep.com/about/investors/.

No director may be deemed independent unless the Board of Directors of UNS Energy affirmatively determines, after due deliberation, that the director has no material relationship with UNS Energy or any of its subsidiaries either directly or as a partner, shareholder or executive officer of an organization that has a relationship with UNS Energy or any of its subsidiaries. In each case, the Board of Directors of UNS Energy broadly considers all the relevant facts and circumstances from the standpoint of the director as well as from that of persons or organizations with which the director has an affiliation and applies these standards.

Annually, the UNS Energy board determines whether each director meets the criteria of independence. Based upon the foregoing criteria, the UNS Energy board has deemed each director of UNS Energy to be independent, with the exception of Messrs. Hutchens, Perry, and Laurito. Mr. Hutchens is the President and Chief Executive Officer of UNS Energy and TEP. Mr. Perry is an executive officer of Fortis. Mr. Laurito is an executive officer of Central Hudson Gas and Electric Corporation, another wholly owned subsidiary of Fortis. For each other director who is deemed independent, there were no other significant transactions, relationships or arrangements that were considered by the UNS Energy board in determining that the director is independent. See Transactions with Related Persons, below.

Each member of UNS Energy's Audit and Risk Committee and Human Resources and Governance Committee meets the independence criteria of both the Director Independence Standards and the NYSE listing standards, with the exception of Mr. Perry, who is an executive officer of Fortis, and Mr. Laurito, who is an executive officer of Central Hudson Gas and Electric Corporation. Mr. Hutchens is not a member of either committee.

Transactions with Related Persons

The UNS Energy Board of Directors has adopted a written Policy on Review of Transactions with Related Persons (“Related Person Policy”) under which it reviews related person transactions. The policy is available on TEP’s website at www.tep.com/about/investors/. The Related Person Policy specifies that certain transactions involving directors, executive officers, significant shareholders and certain other related persons in which UNS Energy or its subsidiaries, including TEP, is or will be a participant and are of the type required to be reported as a related person transaction under Item 404 of Regulation S-K shall be reviewed by the UNS Energy Audit and Risk Committee for the purpose of determining whether such transactions are in the best interest of UNS Energy and its subsidiaries. The Related Person Policy also establishes a requirement for directors and executive officers of UNS Energy and its subsidiaries to report transactions involving a related party that exceed $120,000 in value. TEP is not aware of any transactions entered into since the beginning of last year that did not follow the procedures outlined in the Related Person Policy.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pre-Approved Policies and Procedures

Rules adopted by the SEC in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. UNS Energy’s Audit and Risk Committee has adopted a policy pursuant to which audit, audit-related, tax, and other services are pre-approved by category of service. Recognizing that situations may arise where it is in the Company’s best interest for the auditor to perform services in addition to the annual audit of the Company’s financial statements, the policy sets forth guidelines and procedures with respect to approval of the four categories of service designed to achieve the continued independence of the auditor when it is retained to perform such services for UNS Energy. The policy requires the Audit and Risk Committee to be informed of each service and does not include any delegation of the Audit and Risk Committee’s responsibilities to management. The Audit and Risk Committee may delegate to the Chair of the Audit and Risk Committee the authority to grant pre-approvals of audit and non-audit services requiring Audit and Risk Committee approval where the Audit and Risk Committee Chair believes it is desirable to pre-approve such services prior to the next regularly scheduled Audit and Risk Committee meeting. The decisions of the Audit and Risk Committee Chair to pre-approve any such services from one regularly scheduled Audit Committee meeting to the next shall be reported to the Audit and Risk Committee.

Fees

Effective October 7, 2014, PwC was dismissed as the independent auditors and replaced with Ernst and Young LLP (EY) as a result of the Fortis acquisition. The table details fees paid to EY for professional services during 2015 and 2014. The Audit and Risk Committee has considered whether the provision of services to TEP by EY, beyond those rendered in connection with their audit and review of TEP’s financial statements, is compatible with maintaining their independence as auditor.

TEP's fees for principal accountant services are as follows:

(in thousands)	2015	2014
Audit Fees	$1,352	$1,206
Audit-Related Fees	—	—
Tax Fees	70	84
All Other Fees	—	—
Total	$1,422	$1,290

Audit fees include fees for the audit of TEP’s consolidated financial statements included in TEP’s Annual Report on Form 10-K and review of financial statements included in TEP’s Quarterly Reports on Form 10-Q. Audit fees also include services provided in connection with comfort letters, consents and other services related to SEC matters, financing transactions, and statutory and regulatory audits.

Tax fees reported for 2015 and 2014 include fees for tax appeals, and in 2014 for consulting.

All services performed by our principal accountant are approved in advance by the Audit and Risk Committee in accordance with the Audit and Risk Committee’s pre-approval policy for services provided by the Independent Registered Public Accounting Firm.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Consolidated Financial Statements as of December 31, 2015 and 2014 and for Each of the Three Years in the Period Ended December 31, 2015

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Report of Independent Registered Public Accounting Firm	43
Consolidated Statements of Income	45
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Notes to Consolidated Financial Statements	51

(2) Financial Statement Schedule

All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(3) Exhibits

Reference is made to the Exhibit Index commencing on page 119.

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:	February 18, 2016		/s/ Kevin P. Larson Kevin P. Larson Senior Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:	February 18, 2016		/s/ David G. Hutchens* David G. Hutchens President, Chief Executive Officer, and Director (Principal Executive Officer)
Date:	February 18, 2016		/s/ Kevin P. Larson Kevin P. Larson Senior Vice President, Chief Financial Officer, and Director (Principal Financial Officer)
Date:	February 18, 2016		/s/ Frank P. Marino* Frank P. Marino Vice President and Controller (Principal Accounting Officer)
Date:	February 18, 2016		/s/ Todd C. Hixon* Todd C. Hixon Director
Date:	February 18, 2016	By:	/s/ Kevin P. Larson Kevin P. Larson *As attorney-in-fact for each of the persons indicated

EXHIBIT INDEX

*2(a)	Agreement and Plan of Merger, dated as of December 11, 2013, among FortisUS Inc., Color Acquisition Sub Inc., UNS Energy Corporation and solely for purposes of Section 5.5(a) and 8.15, Fortis Inc. (Form 8-K, dated December 12, 2013, File No. 1-05924 - Exhibit 2.1).
*2(a)(1)	First Amendment to the Agreement and Plan of Merger, dated as of August 14, 2014, by and among FortisUS Inc., Color Acquisition Sub Inc. and UNS Energy Corporation (Form 8-K, dated August 14, 2014, File No. 1-05924 - Exhibit 2.2).
*3(a)	Restated Articles of Incorporation of TEP, filed with the ACC on August 11, 1994, as amended by Amendment to Article Fourth of our Restated Articles of Incorporation, filed with the ACC on May 17, 1996. (Form 10-K for the year ended December 31, 1996, File No. 1-05924 - Exhibit No 3(a)).
*3(a)(1)	TEP Articles of Amendment filed with the ACC on September 3, 2009 (Form 10-K for the year ended December 31, 2010, File No. 1-05924 - Exhibit 3(a)).
*3(b)	Bylaws of TEP, as amended as of August 12, 2015 (Form 10-Q for the quarter ended September 30, 2015, File No. 1-05924 - Exhibit 3).
*3(c)	Amendment to Articles of Incorporation of UNS Energy Corporation, creating series of Limited Voting Junior Preferred Stock (Form 8-K dated August 12, 2015, File No. 1-05924 - Exhibit 3.2).
*4(c)(1)	Indenture of Trust, dated as of March 1, 2008, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Industrial Development Revenue Bonds, 2008 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 19, 2008, File No. 1-05924 - Exhibit 4(a)).
*4(c)(2)	Loan Agreement, dated as of March 1, 2008, between the Industrial Development Authority of the County of Pima and TEP relating to Industrial Development Revenue Bonds, 2008 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 19, 2008, File No. 1-05924 - Exhibit 4(b)).
*4(d)(1)	Indenture of Trust, dated as of June 1, 2008, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Industrial Development Revenue Bonds, 2008 Series B (Tucson Electric Power Company Project). (Form 8-K dated June 25, 2008, File No. 1-05924 - Exhibit 4(a)).
*4(d)(2)	Loan Agreement, dated as of June 1, 2008, between The Industrial Development Authority of the County of Pima and TEP relating to Industrial Development Revenue Bonds, 2008 Series B (Tucson Electric Power Company Project). (Form 8-K dated June 25, 2008, File No. 1-05924 - Exhibit 4(b)).
*4(e)(1)	Indenture of Trust, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(A)).
*4(e)(2)	

	Loan Agreement, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company San Juan Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(B)).
*4(f)(1)	Indenture of Trust, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(C)).

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*4(f)(2)	Loan Agreement, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(D)).
*4(g)(1)	Indenture of Trust, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-05924 Exhibit 4(a)).
*4(g)(2)	Loan Agreement, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-05924 - Exhibit 4(b)).
*4(h)(1)	Indenture of Trust, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(c)).
*4(h)(2)	Loan Agreement, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(d)).
*4(i)(1)	Indenture of Trust, dated as of March 1, 2012, between The Industrial Development Authority of the County of Apache and U.S. Bank Trust National Association, authorizing Pollution Control Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 21, 2012, File No. 1-05924 - Exhibit 4(a)).
*4(i)(2)	Loan Agreement, dated as of March 1, 2012, between The Industrial Development Authority of the County of Apache and TEP, relating to Pollution Control Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 21, 2012, File No. 1-05924 - Exhibit 4(b)).
*4(j)(1)	Indenture of Trust, dated as of June 1, 2012, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated June 21, 2012, File No. 1-05924 - Exhibit 4(a)).
*4(j)(2)	Loan Agreement, dated as of June 1, 2012, between The Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated June 21, 2012, File No. 1-05924 - Exhibit 4(b)).
*4(k)(1)	Indenture of Trust, dated as of March 1, 2013, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Project). (Form 8-K dated March

	14, 2013, File No. 1-05924 - Exhibit 4(a)).
*4(k)(2)	Loan Agreement, dated as of March 1, 2013, between The Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 14, 2013, File No. 1-05924 - Exhibit 4(b)).
*4(l)(1)	Indenture of Trust, dated as of November 1, 2013, between The Industrial Development Authority of the County of Apache and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Springerville Project). (Form 8-K dated November 14, 2013, File No. 1-05924 - Exhibit 4(a)).

*4(l)(2)	Loan Agreement, dated as of November 1, 2013, between The Industrial Development Authority of the County of Apache and Tucson Electric Power Company, relating to Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Springerville Project). (Form 8-K dated November 14, 2013, File No. 1-05924 - Exhibit 4(b)).
*4(l)(3)	Lender Rate Mode Covenants Agreement, dated as of November 1, 2013, between Tucson Electric Power Company and STI Institutional & Government, Inc. (Form 8-K dated November 14, 2013, File No. 1-05924 - Exhibit 4(c)).
*4(l)(4)	Amendment, dated May 26, 2015, between Tucson Electric Power Company, STI Institutional & Government, Inc., and Branch Banking and Trust Company, to Lender Rate Made Covenants Agreement, dated November 1, 2013 (Form 10-Q for the quarter ended June 30, 2015, File No. 1-05924 - Exhibit 4).
*4(m)(1)	Indenture, dated November 1, 2011, between Tucson Electric Power Company and U.S. Bank National Association, as trustee, authorizing unsecured Notes (Form 8-K dated November 8, 2011, File 1-05924 - Exhibit 4.1).
*4(m)(2)	Officers Certificate, dated November 8, 2011, authorizing 5.15% Notes due 2021. (Form 8-K dated November 8, 2011, File No. 1-05924 - Exhibit 4.2).
*4(m)(3)	Officers Certificate, dated September 14, 2012, authorizing 3.85% Notes due 2023. (Form 8-K dated September 14, 2012, File No. 1-05924 - Exhibit 4.1).
*4(m)(4)	Officer's Certificate, dated March 10, 2014, authorizing 5.00% Senior Notes due 2044 (Form 8-K dated March 10, 2014, File No. 1-05924 - Exhibit 4.1).
*4(m)(5)	Officer's Certificate, dated February 27, 2015, authorizing 3.05% Senior Notes due 2025 (Form 8-K dated February 27, 2015, File No. 1-05924 - Exhibit 4(a)).
*4(o)(1)	Reimbursement Agreement, dated as of December 14, 2010, among TEP, as Borrower, the financial institutions from time to time, parties thereto and JPMorgan Chase Bank, N.A., as Administrative Agent and as Issuing Bank. (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(a)).
*4(o)(2)	Amendment No. 1 to Reimbursement Agreement, dated as of February 11, 2014 among TEP, as Borrower, the financial institutions from time to time, parties thereto and JPMorgan Chase Bank, N.A., as Administrative Agent and as Issuing Bank (Form 10-K for the year ended December 31, 2013, File No. 1-05924 - Exhibit 4(t)(2)).
*4(r)(1)	Credit Agreement, dated as of October 15, 2015, among Tucson Electric Power Company, MUFG Union Bank, N.A. as Administrative Agent, and a group of lenders (Form 8-K dated October 15, 2015, File No. 1-05924 - Exhibit 4.1).
*10(b)(1)	Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos Resources Inc. (San Carlos) (a wholly-owned subsidiary of the Registrant) jointly and severally, as Lessee, and Wilmington Trust Company, as Trustee, as amended and supplemented. (Form 10-K for the year ended December 31, 1985, File No. 1-05924 - Exhibit 10(f)(1)).

*10(b)(2)	Tax Indemnity Agreements, dated as of December 1, 1985, between Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Finance Co., each as beneficiary under a separate trust agreement, dated as of December 1, 1985, with Wilmington Trust Company, as Owner Trustee, and William J. Wade, as Co-Trustee, and TEP and San Carlos, as Lessee. (Form 10-K for the year ended December 31, 1985, File No. 1-05924 - Exhibit 10(f)(2)).

*10(b)(3)	Participation Agreement, dated as of December 1, 1985, among TEP and San Carlos as Lessee, Philip Morris Credit Corporation, IBM Credit Financing Corporation, and Emerson Finance Co. as Owner Participants, Wilmington Trust Company as Owner Trustee, The Sumitomo Bank, Limited, New York Branch, as Loan Participant, and Bankers Trust Company, as Indenture Trustee. (Form 10-K for the year ended December 31, 1985, File No. 1-05924 - Exhibit 10(f)(3)).
*10(b)(4)	Restructuring Commitment Agreement, dated as of June 30, 1992, among TEP and San Carlos, jointly and severally, as Lessee, Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Capital Funding, William J. Wade, as Owner Trustee and Co-Trustee, respectively, The Sumitomo Bank, Limited, New York Branch, as Loan Participant and United States Trust Company of New York, as Indenture Trustee. (Form S-4, Registration No. 33-52860 - Exhibit 10(g)(4)).
*10(b)(5)	Lease Supplement No.1, dated December 31, 1985, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee Trustee and Co-Trustee, respectively (document filed relates to Philip Morris Credit Corporation; documents relating to IBM Credit Financing Corporation and Emerson Financing Co. are not filed but are substantially similar). (Form S-4, Registration No. 33-52860 - Exhibit 10(g)(5)).
*10(b)(6)	Amendment No. 1, dated as of December 15, 1992, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 - Exhibit 10(g)(6)).
*10(b)(7)	Amendment No. 1, dated as of December 15, 1992, to Tax Indemnity Agreements, dated as of December 1, 1985, between Philip Morris Credit Corporation, IBM Credit Financing Corporation and Emerson Capital Funding Corp., as Owner Participants and TEP and San Carlos, jointly and severally, as Lessee. (Form S-1, Registration No. 33-55732 - Exhibit 10(g)(7)).
*10(b)(8)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(8)).
*10(b)(9)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit Financing Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(9)).
*10(b)(10)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(10)).
*10(b)(11)	Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Philip

	Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(11)).
*10(b)(12)	Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and IBM Credit Financing Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(12)).

*10(b)(13)	Amendment No. 2, dated as of December 1, 1999, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Emerson Finance Co. as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(13)).
*10(b)(14)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(a)).
*10(b)(15)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit, LLC as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(b)).
*10(b)(16)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(c)).
*10(b)(17)	Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Philip Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(d)).
*10(b)(18)	Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and IBM Credit, LLC as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(e)).
*10(b)(19)	Amendment No. 3 dated as of June 1, 2003, to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Emerson Finance Co. as Owner Participant, beneficiary under a Trust Agreement dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, together as Lessor. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(f)).
*10(b)(20)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with

	Philip Morris Capital Corporation as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.1).
*10(b)(21)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Selco Service Corporation as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.2).
*10(b)(22)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Emerson Finance LLC as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.3).

*10(b)(23)	Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Philip Morris Capital Corporation as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, together as Lessor. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.4).
*10(b)(24)	Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Selco Service Corporation as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, together as Lessor. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.5).
*10(b)(25)	Amendment No. 4, dated as of June 1, 2006 to Tax Indemnity Agreement, dated as of December 1, 1985, between TEP and San Carlos, as Lessee, and Emerson Finance LLC as Owner Participant, beneficiary under a Trust Agreement, dated as of December 1, 1985, with Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, together as Lessor. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.6).
*10(c)(1)	Participation Agreement, dated as of June 30, 1992, among TEP, as Lessee, various parties thereto, as Owner, Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, and LaSalle National Bank, as Indenture Trustee relating to TEP's lease of Springerville Unit 1. (Form S-1, Registration No. 33-55732 - Exhibit 10(u)).
*10(c)(2)	Lease Agreements, dated as of December 15, 1992, between TEP, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 - Exhibit 10(v)).
*10(c)(3)	Tax Indemnity Agreements, dated as of December 15, 1992, between the various Owner Participants parties thereto and TEP, as Lessee. (Form S-1, Registration No. 33-55732 - Exhibit 10(w)).
+10(d)	UNS Energy Officer Change in Control Agreement (a schedule of officers who are covered by the agreement or substantially identical agreements is filed separately), between UNS Energy and officers of UNS Energy.
+10(d)(1)	Schedule of Officers covered by UNS Energy Officer Change in Control Agreement or substantially Identical Agreements.
+*10(f)	Retention Bonus Agreement between Kevin P. Larson and UNS Energy Corporation (Form 8-K, dated November 13, 2014, File No. 1-05924 - Exhibit 10(a)).
+*10(g)	UNS Energy Corporation 2015 Share Unit Plan (Form 8-K, dated February 23, 2015, File No. 1-05924-Exhibit 10(a)).
12	Computation of Ratio of Earnings to Fixed Charges.
21	Subsidiaries of the Registrant.
24	Power of Attorney.

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 Kevin P. Larson.
**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

* Previously filed as indicated and incorporated herein by reference.

+ Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

** 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.

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