UNS Energy Corp
Form 10-K
February 25, 2014

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

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

For the fiscal year ended December 31, 2013
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	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	UNS ENERGY CORPORATION (An Arizona Corporation) 88 East Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	TUCSON ELECTRIC POWER COMPANY (An Arizona Corporation) 88 East Broadway Boulevard Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UNS Energy Corporation	Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Tucson Electric Power Company	Common Stock, without par value	N/A

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UNS Energy Corporation	Yes x	No ¨
Tucson Electric Power Company	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).

UNS Energy Corporation	Yes ¨	No x
Tucson Electric Power Company	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 Exchange Act 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.

UNS Energy Corporation	Yes x	No ¨
Tucson Electric Power Company	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).

UNS Energy Corporation	Yes x	No ¨
Tucson Electric Power Company	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. ý

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):

UNS Energy Corporation	Large Accelerated Filer	x	Accelerated Filer	¨
	Non-accelerated Filer	¨	Smaller Reporting Company	¨
Tucson Electric Power Company	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).

UNS Energy Corporation	Yes ¨	No x
Tucson Electric Power Company	Yes ¨	No x

The aggregate market value of UNS Energy Corporation voting Common Stock held by non-affiliates of the registrant was $1,855,552,035 based on the last reported sale price thereof on the consolidated tape on June 30, 2013.

As of February 14, 2014, 41,633,535 shares of UNS Energy Corporation Common Stock, no par value (the only class of Common Stock), were outstanding. As of February 14, 2014, Tucson Electric Power Company had 32,139,434 shares of common stock outstanding, no par value, all of which were held by UNS Energy Corporation.

Tucson Electric Power Company meets the conditions set forth in General Instructions (I)(1)(a) and (b) on Form 10-K and is therefore filing this report with the reduced disclosure format.

Documents incorporated by reference: Specified portions of UNS Energy Corporation's Proxy Statement relating to the 2014 Annual Meeting of Shareholders are incorporated by reference into Part III.

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DEFINITIONS

The abbreviations and acronyms used in the 2013 Form 10-K are defined below:

ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
Base O&M	A non-GAAP financial measure that represents the fundamental level of operating and maintenance expense related to our business
Base Rates	The portion of TEP's and UNS Electric's Retail Rates attributed to generation, transmission, distribution costs, and customer charge; and UNS Gas' delivery costs and customer charge. Base Rates exclude costs that are passed through to customers for fuel and purchased energy costs
Btu	British thermal unit(s)
Cooling Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures
DSM	Demand Side Management
ECA	Environmental Compliance Adjustor
Entegra	a subsidiary of Entegra Power Group LLC
FERC	Federal Energy Regulatory Commission
FVRB	Fair Value Rate Base
Fortis	FortisUS, Inc., a Delaware corporation whose ultimate parent company is Fortis Parent
Fortis Parent	Fortis, Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada
Four Corners	Four Corners Generating Station
GBtu	Billion British thermal units
GWh	Gigawatt-hour(s)
Gila River Unit 3	Unit 3 of the Gila River Generating Station
Heating Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting the average of the high and low daily temperatures from 65
kV	Kilo-volt
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery Mechanism
Millennium	Millennium Energy Holdings, Inc., a wholly-owned subsidiary of UNS Energy Corporation
MMBtu	Million British thermal units
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
NTUA	Navajo Tribal Utility Authority
OATT	Open Access Transmission Tariff
OCRB	Original Cost Rate Base
PGA	Purchased Gas Adjustor, a Retail Rate mechanism designed to recover the cost of gas purchased for retail gas customers
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
REC	Renewable Energy Credit
RES	Renewable Energy Standard

Regional Haze Rules	Rules promulgated by the EPA to improve visibility at national parks and wilderness areas

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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 Leases	Coal handling facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities	Facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities Leases	Leveraged lease arrangements relating to an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 1	Unit 1 of the Springerville Generating Station
Springerville Unit 1 Leases	Leveraged lease arrangement relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 2	Unit 2 of the Springerville Generating Station
Springerville Unit 3	Unit 3 of the Springerville Generating Station
Springerville Unit 4	Unit 4 of the Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
Sundt Unit 4	Unit 4 of the H. Wilson Sundt Generating Station
TCA	Transmission Cost Adjustor
TEP	Tucson Electric Power Company, the principal subsidiary of UNS Energy Corporation
Therm	A unit of heating value equivalent to 100,000 Btus
Tri-State	Tri-State Generation and Transmission Association, Inc.
UED	UniSource Energy Development Company, a wholly-owned subsidiary of UNS Energy Corporation
UES	UniSource Energy Services, Inc., a wholly-owned subsidiary of UNS Energy, and intermediate holding company established to own the operating companies UNS Electric and UNS Gas
UNS Electric	UNS Electric, Inc., a wholly-owned subsidiary of UES
UNS Energy	UNS Energy Corporation (formerly known as UniSource Energy Corporation)
UNS Gas	UNS Gas, Inc., a wholly-owned subsidiary of UES

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PART I

This combined Form 10-K is being filed separately by UNS Energy Corporation (UNS Energy) and Tucson Electric Power Company (TEP) (collectively, the Registrants). Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. TEP does not make any representation as to information relating to any other subsidiary of UNS Energy.

This Annual Report on Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. You should read forward-looking statements together with the cautionary statements and important factors included elsewhere in this Form 10-K (See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Safe Harbor for Forward-Looking Statements). Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions. Forward-looking statements are not statements of historical facts. Forward-looking statements may be identified by the use of words such as "anticipates," "estimates," "expects," "intends," "plans," "predicts," "projects," and similar expressions. 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. In addition, UNS Energy and TEP disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

ITEM 1. – BUSINESS

OVERVIEW OF CONSOLIDATED BUSINESS

UNS Energy is a utility services holding company engaged, through its subsidiaries, in the electric generation and energy delivery business. Each of UNS Energy's subsidiaries is a separate legal entity with its own assets and liabilities. UNS Energy owns 100% of TEP, UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium), and UniSource Energy Development Company (UED).

TEP is a regulated utility and UNS Energy's largest operating subsidiary, representing approximately 83% of UNS Energy's total assets at December 31, 2013. TEP generates, transmits and distributes electricity to approximately 413,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. In addition, TEP operates Springerville Generating Station (Springerville) Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agriculture Improvement and Power District (SRP).

UES holds the common stock of two regulated utilities, UNS Electric, Inc. (UNS Electric) and UNS Gas, Inc. (UNS Gas). UNS Electric is a regulated utility, which generates, transmits and distributes electricity to approximately 93,000 retail customers in Mohave and Santa Cruz counties in Arizona. UNS Gas is a regulated gas distribution company, which services approximately 150,000 retail customers in Mohave, Yavapai, Coconino, Navajo, and Santa Cruz counties in Arizona.

UED and Millennium's investments in unregulated businesses represent less than 1% of UNS Energy's assets as of December 31, 2013.

References in this report to "we" and "our" are to UNS Energy and its subsidiaries, collectively.

AGREEMENT AND PLAN OF MERGER

In December 2013, UNS Energy entered into an Agreement and Plan of Merger (the Merger Agreement) with FortisUS Inc., a Delaware corporation (Fortis), Color Acquisition Sub Inc., an Arizona corporation and a wholly owned subsidiary of Fortis (Merger Sub), and, solely for the purposes of Sections 5.5(c) and 8.15 of the Merger Agreement, Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador and the parent company of Fortis (Fortis Parent).

The Merger Agreement provides for a business combination whereby Merger Sub will merge with and into UNS Energy (the Merger). As a result of the Merger, the separate corporate existence of Merger Sub will cease and UNS Energy will continue as a wholly owned subsidiary of Fortis. The Boards of Directors of each of UNS Energy and Fortis Parent have approved the Merger.

Under the Merger Agreement, at the effective time of the Merger, each outstanding share of UNS Energy common stock (other than shares owned by UNS Energy, Fortis Parent, Fortis or Merger Sub or their subsidiaries) will be converted into the right to receive $60.25 in cash (the Merger Consideration). At the effective time and as a result of the Merger, each outstanding option to acquire UNS Energy common stock issued by UNS Energy will be converted into the right to receive the difference between

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the Merger Consideration and the exercise price of the option, on a per-share basis, and each outstanding share of restricted stock, restricted stock unit, performance share and other equity-based awards will vest and be converted into the right to receive the Merger Consideration.

The Merger is subject to the approval of stockholders holding a majority of the outstanding shares of UNS Energy and other customary closing conditions, including, among other things:

- the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended;
- approvals of the Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC);
- confirmation of review, without unresolved concerns, from the Committee on Foreign Investment in the United States; and
- the absence of any injunction, order or other law prohibiting the Merger.

The obligations of each party to close the Merger are also subject to the accuracy of representations and warranties of, and compliance with covenants by, the other parties as set forth in the Merger Agreement, and, in the case of Fortis, the absence of any material adverse effect on UNS Energy.

The Merger Agreement provides that Fortis and UNS Energy may mutually agree to terminate the Merger Agreement before completing the Merger. In addition, either Fortis or UNS Energy may decide to terminate the Merger Agreement if, among other things:

- the Merger is not consummated by December 11, 2014, subject to extension to June 11, 2015 if regulatory approvals have not been obtained (or further if approvals have been obtained but have not yet become final orders), but other closing conditions have been satisfied or waived;
- UNS Energy stockholders fail to adopt the Merger Agreement;
- a court or other governmental entity issues a final and nonappealable order prohibiting the Merger; or
- the other party breaches the Merger Agreement in a way that would entitle the party seeking to terminate the Merger Agreement not to consummate the Merger, subject to the right of the breaching party to cure the breach.

UNS Energy may also terminate the Merger Agreement prior to receiving stockholder approval, after complying with certain procedures set forth in the Merger Agreement, in order to accept a superior takeover proposal upon payment of a termination fee of approximately $64 million (Termination Fee). Fortis may terminate the Merger Agreement and require payment of the Termination Fee if UNS Energy enters into an agreement with respect to a superior takeover proposal, or if the Board of Directors of UNS Energy recommends or proposes to approve or recommend any alternative takeover proposal with a third party, or withdraws, modifies or proposes publicly to withdraw or modify its approval or recommendation with respect to the Merger Agreement. The Merger Agreement further provides that, upon termination under certain other circumstances, UNS Energy may be obligated to reimburse up to $12.5 million of Fortis' expenses with respect to the transaction and, if another takeover proposal is agreed or consummated, pay Fortis the Termination Fee (net of any expense reimbursement previously paid).

Fortis has agreed to maintain UNS Energy's community involvement efforts and charitable donations for five years following the closing and to keep UNS Energy's headquarters in Tucson, Arizona. Fortis has also agreed to retain four of UNS Energy's current directors on the board of UNS Energy following the closing.

UNS Energy and Fortis have agreed to customary representations, warranties and covenants in the Merger Agreement, including, among others, covenants (i) with respect to the conduct of its business during the interim period between the execution of the Merger Agreement and consummation of the Merger, (ii) not to solicit proposals regarding alternative business combination transactions and (iii) not to engage in certain kinds of transactions during such period. UNS Energy and Fortis have agreed to use their reasonable best efforts to obtain required governmental approvals to effect the transaction.

On February 18, 2014, we filed definitive proxy materials with the SEC. We expect UNS Energy's shareholders to formally consider a proposal to approve the Merger Agreement at a meeting on March 26, 2014.

In January 2014, UNS Energy and Fortis Parent filed an application and supporting testimony with the ACC requesting approval of the Merger. The ACC administrative law judge (ALJ) assigned to this matter issued a procedural order that provides for settlement discussions to commence on April 28, 2014, and a hearing before the ALJ to commence on June 16, 2014. In February 2014, we filed an application with FERC requesting approval of the

Merger. The Merger is expected to close by the end of 2014.

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BUSINESS SEGMENT CONTRIBUTIONS

The table below shows the contributions to our consolidated after-tax earnings by our three business segments.

	2013	2012	2011
	Millions of Dollars		
TEP	$101	$65	$85
UNS Electric	12	17	18
UNS Gas	11	9	10
Other Non-Reportable Segments and Adjustments[(1)]	3	—	(3)
Consolidated Net Income	$127	$91	$110

(1) Includes: UNS Energy parent company expenses, Millennium, UED, and intercompany eliminations.

See Note 4 for additional financial information regarding our business segments.

Rates and Regulation of TEP, UNS Electric, and UNS Gas

The ACC regulates portions of TEP's, UNS Electric's, and UNS Gas' utility accounting practices and energy rates. The ACC has authority over rates charged to retail customers, the issuance of securities, and transactions with affiliated parties. Our regulated utility rates for retail electric and natural gas service are determined on a “cost of service” basis. Retail Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for our utility businesses to earn a reasonable return on rate base. Rate base is generally determined by reference to the original cost (net of depreciation) of utility plant in service to the extent deemed used and useful, and to various adjustments for deferred taxes and other items, plus a working capital component. Over time, additions to utility plant in service increase rate base while depreciation of utility plant reduces rate base.

The rates charged to retail customers also include pass-through mechanisms that allow each utility to recover the prudently incurred actual costs of its fuel, transmission, and energy purchases.

The FERC regulates the terms and prices of transmission services and wholesale electricity sales, wholesale transport and purchases of natural gas, and portions of our accounting practices. TEP and UNS Electric have FERC tariffs to sell power at market-based rates.

TEP

TEP was incorporated in the State of Arizona in 1963. TEP is the principal operating subsidiary of UNS Energy. In 2013, TEP’s electric utility operations contributed 81% of UNS Energy’s operating revenues and comprised 83% of its assets at year end.

SERVICE AREA AND CUSTOMERS

TEP is a vertically integrated utility that provides regulated electric service to approximately 413,000 retail customers in southeastern Arizona. TEP’s service territory covers 1,155 square miles and includes a population of approximately one million people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells electricity to other entities in the western United States.

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 opportunities for customers to generate their own electricity.

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Customer Base

The table below shows the percentage distribution of TEP's energy sales by major customer class over the last three years. In 2014, the retail energy consumption by customer class is expected to be similar to the historical distribution.

	2013		2012		2011	
Residential	42	%	41	%	42	%
Commercial	23	%	24	%	23	%
Non-mining Industrial	23	%	23	%	23	%
Mining	12	%	12	%	12	%

Local, regional, and national economic factors can impact the growth in the number of customers in TEP's service territory. In 2013, 2012, and 2011, TEP's average number of retail customers increased by less than 1% in each year. We expect the number of TEP's retail customers to increase at a rate of approximately 1% in 2014 and 2015.

Two of TEP's largest retail customers are in the copper mining industry. TEP's kilowatt-hour (kWh) sales to mining customers depend on a variety of factors including the market price of copper, the electricity rate paid by mining customers, and the mines' potential development of their own electric generation resources. TEP's kWh sales to mining customers decreased by 1.2% in 2013 due in part to a higher occurrence of planned and unplanned maintenance at the mines that reduced the mines' demand for electricity.

See Part II, Item. 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power, Factors Affecting Results of Operations, Sales to Mining Customers.

Retail Sales Volumes

During the past three years, economic conditions and state requirements for energy efficiency and distributed generation have negatively affected retail electricity sales. TEP's retail sales volumes in 2013 were approximately 9,279 Gigawatt-hours (GWh). These volumes were 0.1% below 2010 levels.

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. See Generating and Other Resources, Purchases and Interconnections, below.

Generally, TEP commits to future sales based on expected excess 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 of sales:

Long-Term Sales

Long-term wholesale sales contracts cover periods of more than one year. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers. TEP's two primary long-term contracts are with Salt River Project Agriculture Improvement and Power District (SRP) and the Navajo Tribal Utility Authority (NTUA). See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations, Long-Term Wholesale Sales.

Short-Term 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, three-month, or one-year 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. All 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. See Rates and Regulation, below.

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GENERATING AND OTHER RESOURCES

At December 31, 2013, TEP owned or leased 2,240 MW of generating capacity, as set forth in the following table:

Generating Source	Unit No.	Location	Date In Service	Resource Type	Capacity MW	Operating Agent	TEP's Share %	MW
Springerville Station[1]	1	Springerville, AZ	1985	Coal	387	TEP	100.0	387
Springerville Station	2	Springerville, AZ	1990	Coal	390	TEP	100.0	390
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	784	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	784	APS	7.0	55
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station	4	Tucson, AZ	1967	Coal/Gas	156	TEP	100.0	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	1972	Gas/Oil	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	Gas	95	TEP	100.0	95
Springerville Solar Station		Springerville, AZ	2002-2010	Solar	6	TEP	100.0	6
Tucson Solar Projects		Tucson, AZ	2010-2012	Solar	12	TEP	100.0	12
Total TEP Capacity [2]								2,240

(1) Leased asset as of December 31, 2013.

(2) Excludes 683 MW of additional resources, which consist of certain capacity purchases and interruptible retail load. At December 31, 2013, total owned capacity was 1,853 MW and leased capacity was 387 MW.

Springerville Generating Station

TEP leases 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 are accounted for as capital leases. The leases expire in January 2015 and include fair market value renewal and purchase options. TEP owns a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 megawatts (MW) of capacity.

Unit 2 of the Springerville Generating Station (Springerville Unit 2) is owned by San Carlos Resources, Inc. (San Carlos), a wholly-owned subsidiary of TEP. TEP's other interests in the Springerville Generating Station (Springerville) include leasehold interests in the Springerville Coal Handling Facilities and in a one-half interest in certain other facilities at Springerville used in common by all four Springerville units (Springerville Common Facilities).

Springerville Unit 1 Leases

TEP leases 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 are accounted for as capital leases. The leases expire in January 2015 and include fair market value renewal and purchase options. In 2006, TEP purchased a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 MW of capacity.

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During 2013, TEP agreed to purchase leased interests of 35.4% or 137 MW of Springerville Unit 1, for an aggregate purchase price of approximately $65 million. TEP expects to complete the purchases in December 2014 and in January 2015. See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations, Springerville Unit 1.

Springerville Common Facilities Leases

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

Springerville Coal Handling Facilities Lease

In 1984, TEP sold and leased back the Springerville Coal Handling Facilities. Since entering the lease, TEP purchased a 13% ownership interest in the Springerville Coal Handling Facilities. The terms of the Springerville Coal Handling Facilities Leases expire in April 2015 but have fixed-rate renewal options if certain conditions are satisfied as well as a fixed-price purchase provision of $120 million.

See Note 6 and Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Liquidity and Capital Resources, Contractual Obligations.

Sundt Generating Station

The H. Wilson 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.

Future Generating Resources

Gila River Generating Station Unit 3

In December 2013, TEP and UNS Electric entered into an agreement (the Purchase Agreement) with a subsidiary of Entegra Power Group LLC (Entegra) to purchase Unit 3 of the Gila River Generating Station (Gila River Unit 3). The purchase price of $219 million is subject to adjustments to prorate certain fees and expenses through the closing and in respect of certain operational matters. Gila River Unit 3 is a gas-fired combined cycle unit with a capacity rating of 550 MW, located in Gila Bend, Arizona.

It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 (413 MW) for approximately $164 million and UNS Electric will purchase the remaining 25% undivided interest (137 MW) for approximately $55 million, although TEP and UNS Electric may modify the percentage ownership allocation between them. We expect the transaction to close in December 2014. See TEP, Factors Affecting Results of Operations, Gila River Generating Station Unit 3 and UNS Electric, Factors Affecting Results of Operations, Gila River Generating Station Unit 3. See also Note 8.

The purchase of Gila River Unit 3, which would replace the expiring coal-fired leased capacity from Springerville Unit 1 and the expected reduction of coal-fired generating capacity from San Juan Unit 2, is consistent with TEP's strategy to diversify its generation fuel mix. For more information on San Juan Unit 2, see Environmental Matters, Regional Haze Rules, San Juan, below.

Renewable Energy Resources

Owned Resources

As of December 31, 2013, TEP owned 18 MW of photovoltaic (PV) solar generating capacity. The Springerville solar system, which is located near the Springerville Generating Station, has a total capacity of 6 MW. TEP's remaining 12 MW of PV solar generating capacity is located in the Tucson area.

In 2014, TEP expects to complete solar projects providing capacity of 20 MW at Ft. Huachuca, Arizona and 10 MW in Springerville, Arizona.

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Power Purchase Agreements

In order to meet the ACC's renewable energy requirements, TEP has power purchase agreements (PPAs) for 124 MW of capacity from solar resources, 102 MW of capacity from wind resources and 4 MW of capacity from a landfill gas generation plant. At December 31, 2013, approximately 88 MW of contracted solar resources and 51 MW of contracted wind resources were operational. The remaining resources are expected to be developed over the next several years. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future period. See Rates and Regulation, Renewable Energy Standard and Tariff, below.

Purchases and Interconnections

TEP purchases power from other utilities and power marketers. TEP may enter into contracts: (a) to purchase energy under long-term contracts to serve retail load and long-term wholesale contracts, (b) to purchase capacity or energy during periods of planned outages or for peak summer load conditions, and (c) to purchase 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.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power transmission systems, including TEP, are subject to mandatory reliability standards that are developed and enforced by the North American Electric Reliability Corporation (NERC) and subject to the oversight of the FERC. TEP periodically reviews its operating policies and procedures to ensure continued compliance with these standards.

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 owners of Springerville Units 3 and 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. See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations, Springerville Units 3 and 4.

Peak Demand and Resources

Peak Demand	2013		2012		2011		2010		2009	
	MW									
Retail Customers	2,230		2,290		2,334		2,333		2,354	
Firm Sales to Other Utilities	484		286		322		340		385	
Coincident Peak Demand (A)	2,714		2,576		2,656		2,673		2,739	
Total Generating Resources	2,240		2,267		2,262		2,245		2,229	
Other Resources [(1)]	775		683		1,009		799		781	
Total TEP Resources (B)	3,015		2,950		3,271		3,044		3,010	
Total Margin (B) – (A)	301		374		615		371		271	
Reserve Margin (% of Coincident Peak Demand)	11	%	15	%	23	%	14	%	10	%

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

Peak demand occurs during the summer months due to the cooling requirements of TEP's retail customers. Retail peak demand varies from year-to-year due to weather, economic conditions, and other factors. TEP's retail peak demand declined over the period of 2009 to 2013 due primarily to weak economic conditions and the implementation of energy efficiency programs.

The chart above shows the relationship over a five-year period between TEP’s peak demand and its energy resources. TEP’s total margin is the difference between total energy resources and coincident peak demand, and the reserve margin is the ratio of

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margin to coincident peak demand. TEP's reserve margin in 2013 was in compliance with reliability criteria set forth by the Western Electricity Coordinating Council, a regional council of NERC.

Forecasted retail peak demand for 2014 is 2,253 MW compared with actual peak demand of 2,230 MW in 2013. TEP's 2014 estimated retail peak demand is based on weather patterns observed over a 10-year period. TEP believes existing generation capacity and power purchase agreements are sufficient to meet expected demand in 2014.

FUEL SUPPLY

Fuel and Purchased Power Summary

Resource information is provided below:

	Average Cost per kWh (cents per kWh)			Percentage of Total kWh Resources		
	2013	2012	2011	2013	2012	2011
Coal	2.66	2.54	2.56	75 %	72 %	73 %
Gas	4.57	4.54	5.99	8 %	11 %	7 %
Purchased Power	4.83	3.44	3.94	17 %	17 %	20 %
All Sources	3.54	3.19	3.30	100 %	100 %	100 %

Coal

TEP's principal fuel for electric generation is low-sulfur, bituminous or sub-bituminous coal from mines in Arizona and New Mexico. More than 90% of TEP's coal supply is purchased under long-term contracts, which results in more predictable prices. The average cost per ton of coal, including transportation, was $48.51 in 2013, $45.84 in 2012, and $46.64 in 2011.

Station	Coal Supplier	2013 Coal Consumption (tons in 000's)	Contract Expiration	Avg. Sulfur Content	Coal Obtained From[1]
Springerville	Peabody Coalsales	3,172	2020	1.0%	Lee Ranch Coal Co.
Four Corners[2]	BHP Billiton	381	2016	0.8%	Navajo Indian Tribe
San Juan	San Juan Coal Co.	1,306	2017	0.8%	Federal and State Agencies
Navajo	Peabody Coalsales	560	2019	0.6%	Navajo and Hopi Indian Tribes

(1) Substantially all of the suppliers' mining leases extend at least as long as coal is being mined in economic quantities.

(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 BPH Billiton and will begin operating the mine in 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 presently estimated remaining lives.

Prior to 2010, Sundt Unit 4 was predominantly fueled by coal; however, the generating station also can be operated with natural gas. Both fuels are combined with methane, a renewable energy resource, delivered from a nearby landfill. Since 2010, TEP has fueled Sundt Unit 4 with both coal and natural gas depending on which resource is most economic. In 2014, TEP expects to fuel Sundt Unit 4 primarily with existing coal supplies at the site. See Note 7.

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 (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 a nearby coal mine and a dedicated rail delivery system. The coal supplies are under long-term contracts administered by the

operating agents. TEP expects the available coal reserves of the suppliers to these three jointly-owned generating facilities to be sufficient for the remaining estimated lives of the stations.

Natural Gas Supply

TEP typically 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. TEP purchases gas from Southwest Gas Corporation under a retail tariff for North Loop's 95 MW of internal combustion turbines and receives distribution service under a transportation agreement for DeMoss Petrie, a 75 MW internal combustion turbine. 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 and buys gas from third-party suppliers for Sundt and DeMoss Petrie.

TEP also purchases gas transportation for Luna Generating Station (Luna) from EPNG from the San Juan and Permian Basins, utilizing firm transportation agreements with EPNG.

TRANSMISSION ACCESS

TEP has transmission access and power transaction arrangements with over 140 electric systems or suppliers. TEP also has various ongoing projects that are designed to increase access to the regional wholesale energy market and improve the reliability, capacity and efficiency of its existing transmission and distribution systems.

TEP is participating in the continuation of the 500 kV transmission line from the Pinal West substation to the Pinal Central substation. This project is expected to be in service in 2014. TEP is also finalizing the engineering design for a 40-mile 500-kV transmission line from the Pinal Central substation to TEP's Tortolita substation northwest of Tucson to further enhance its ability to access the region's energy resources. TEP expects the Pinal Central to Tortolita line to be in service in 2016. As a result of these transmission additions, TEP expects that its ability to import energy into its service territory would increase by at least 250 MW.

Discontinued Transmission Project

TEP and UNS Electric are parties to a transmission line project initiated in response to an order by the ACC to UNS Electric to improve the reliability of electric service in Nogales, Arizona. TEP had previously capitalized $11 million related to the project, including $2 million to secure land and land rights. UNS Electric had previously capitalized $0.4 million related to the project.

TEP and UNS Electric will not proceed with the project based on the estimated cost of the proposed line, the difficulty in reaching agreement with the Forest Service on a path for the line, and concurrence by the ACC of transmission plans filed by TEP and UNS Electric supporting the elimination of this project. In 2012, TEP and UNS Electric wrote off a portion of the capitalized costs believed not probable of recovery and recorded a regulatory asset for the balance deemed probable of recovery. TEP and UNS Electric believe it is probable that we will recover at least $5 million and $0.2 million, respectively, of costs incurred through 2013. See Note 7.

RATES AND REGULATION

2013 TEP Rate Order

In June 2013, the ACC issued an order (2013 TEP Rate Order) that resolved the rate case filed by TEP in July 2012, which was based on a test year ended December 31, 2011. The 2013 TEP Rate Order approved new rates effective July 1, 2013. See Item 7. - Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power, Factors Affecting Results of Operations, 2013 TEP Rate Order.

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 prudent 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 will reconcile any over/under collected amounts from the preceding 12-month period and will be 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 SO2 emissions, net of sulfur credits received from TEP's coal suppliers; broker fees; 100% of short-term wholesale revenues and all of the proceeds from the sale of SO2 allowances.

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The 2013 TEP Rate Order approved a new PPFAC rate, effective July 1, 2013, which is a credit to retail customers of 0.14 cents per kWh. This PPFAC rate will be in effect until the rate is reset by the ACC in the second quarter of 2014. TEP's current PPFAC rate includes:

- a reduction in the PPFAC bank balance, recorded in June 2013 as an increase to fuel expense, of $3 million related to prior sulfur credits; and
- a transfer of $10 million, recorded in June 2013, from the PPFAC bank balance to a new regulatory asset to defer coal costs related to the San Juan mine fire. These costs will be eligible for recovery through the PPFAC upon final insurance settlement.

Beginning on July 1, 2013, net lime expense is recovered through the PPFAC; these expenses were previously recorded in O&M expense.

At December 31, 2013, TEP had under-collected fuel and purchased power costs on a billed-to-customer basis of $14 million.

In February 2014, TEP filed a request with the ACC to reset the PPFAC in order to collect the under-collected balance from customers.

Renewable Energy Standard and Tariff

The ACC's Renewable Energy Standard (RES) requires TEP, UNS Electric, 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. Affected utilities must file annual RES implementation plans for review and approval by the ACC. The approved cost of carrying out those plans is recovered from retail customers through the RES surcharge. In 2010, the ACC approved a funding mechanism that allows TEP to recover operating costs, depreciation, property taxes, and a return on investments in company-owned solar projects through RES funds until such costs are reflected in TEP's Base Rates.

In October 2013, the ACC approved TEP's 2014 RES implementation plan. Under the plan, TEP expects to collect approximately $34 million from retail customers during 2014 to fund the following: the above market cost of renewable energy purchases; performance based incentives for customer installed distributed generation; a return on and of TEP's investments in company-owned solar projects; and various other program costs. The plan includes approval for a TEP investment of $28 million in 2014 for company-owned solar projects and an additional $12 million in 2015. TEP met the 2013 RES renewable energy target of 4.0% of retail kWh sales and expects to meet the 2014 target of 4.5%.

Electric Energy Efficiency Standards

In 2010, the ACC approved new Electric EE Standards designed to require electric utilities to implement cost-effective programs to reduce customers' energy consumption. The Electric EE Standards require increasing annual targeted retail kWh savings equal to 22% by 2020. Since the implementation of the Electric EE Standards, TEP's cumulative annual energy savings is approximately 4.4% of retail kWh sales.

DSM programs approved by the ACC, direct load control programs, and energy efficient building codes are acceptable means to meet the Electric EE Standards as set forth by the ACC.

The 2013 TEP Rate Order approved (i) a Lost Fixed Cost Recovery (LFCR) mechanism that will allow TEP to recover certain non-fuel costs that would otherwise go unrecovered due to reduced kWh sales attributed to energy efficiency programs and distributed generation, and (ii) an energy efficiency provision that included a 2013 calendar year budget to fund programs that support the ACC's Electric EE Standards as well as a new performance incentive. See Item. 7-Management's Discussion and Analysis of Financial Condition and Result of Operations, Tucson Electric Power, Factors Affecting Results of Operations, 2013 TEP Rate Order.

Competition

Retail Electric Competition Rules

In 1999, the ACC approved the Retail Electric Competition Rules (Rules) that provided a framework for the introduction of retail electric competition in Arizona. Certain portions of the Rules that enabled Electric Service Providers (ESPs) to compete in the retail market were invalidated by an Arizona Court of Appeals decision in 2004. During 2012 and 2013, several companies filed applications for a Certificate of Convenience and Necessity (CC&N)

with the ACC to provide competitive

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retail electric services in TEP's service territory as an ESP. Unless and until the ACC clarifies the Rules and/or grants a CC&N to an ESP, it is not possible for TEP's retail customers to use an alternative ESP.

In May 2013, the ACC considered the possibility of opening Arizona to retail electric competition. After receiving comments from various parties, the ACC voted to close the docket in September 2013 and did not take any steps to implement retail electric competition. See Item. 7—Management's Discussion and Analysis of Financial Condition and Result of Operations, Tucson Electric Power, Factors Affecting Results of Operations, Competition, Retail Electric Competition Rules.

Technological Developments and Energy Efficiency

New technological developments and the implementation of the Electric EE Standards have reduced energy consumption by TEP's retail customers. TEP's customers also have the ability to install renewable energy technologies and conventional generation units that could reduce their reliance on TEP's services.

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TEP'S UTILITY OPERATING STATISTICS

	2013	2012	2011	2010	2009
Generation and Purchased Power – kWh (000)					
Remote Generation	10,586,972	10,284,612	10,005,127	9,077,032	9,134,183
Local Tucson Generation (Oil, Gas, & Coal)	674,443	803,146	906,496	1,492,885	1,131,399
Renewable Generation	38,206	44,930	28,049	24,511	23,712
Purchased Power	2,328,581	2,328,420	2,686,918	2,846,005	3,809,890
Total Generation and Purchased Power	13,628,202	13,461,108	13,626,590	13,440,433	14,099,184
Less Losses and Company Use	885,026	789,613	822,220	879,423	936,206
Total Energy Sold	12,743,176	12,671,495	12,804,370	12,561,010	13,162,978
Sales – kWh (000)					
Residential	3,866,665	3,820,637	3,888,011	3,869,540	3,905,696
Commercial	2,187,095	2,187,617	2,184,241	2,171,694	2,205,045
Industrial	2,113,659	2,132,214	2,145,163	2,138,749	2,160,946
Mining	1,079,150	1,092,518	1,083,071	1,079,327	1,064,830
Other	32,350	31,833	31,621	32,478	34,226
Total – Electric Retail Sales	9,278,919	9,264,819	9,332,107	9,291,788	9,370,743
Electric Wholesale Sales	3,464,257	3,406,676	3,472,263	3,269,222	3,792,235
Total Electric Sales	12,743,176	12,671,495	12,804,370	12,561,010	13,162,978
Operating Revenues ($000)					
Residential	$400,999	$387,840	$383,908	$372,212	$377,761
Commercial	252,547	247,157	241,044	233,567	236,836
Industrial	164,433	166,739	164,024	159,937	163,720
Mining	65,094	66,158	65,720	62,112	61,033
Other	2,809	2,693	2,601	2,593	2,723
RES, DSM, ECA and LFCR	48,475	45,292	46,633	37,767	25,443
Total – Electric Retail Sales	934,357	915,879	903,930	868,188	867,516
Wholesale Revenue- Long-Term	26,203	24,910	41,056	55,653	48,249
Wholesale Revenue- Short-Term	91,467	71,257	72,798	71,435	84,410
California Power Exchange Provision for Wholesale Refunds	—	—	—	(2,970)	(4,172)
Transmission	14,830	15,793	16,392	20,863	18,974
Other Revenues	129,833	133,821	122,210	112,098	84,361
Total Operating Revenues	$1,196,690	$1,161,660	1,156,386	$1,125,267	$1,099,338
Customers (End of Period)					
Residential	372,411	369,480	367,396	366,217	365,157
Commercial	37,913	37,672	37,536	37,215	37,027
Industrial	617	632	636	635	629
Mining	4	4	4	4	4
Public Authorities	1,857	1,833	1,814	1,829	1,839
Total Retail Customers	412,802	409,621	407,386	405,900	404,656
Average Retail Revenue per kWh Sold (cents)					
Residential	10.4	10.2	9.9	9.6	9.7
Commercial	11.5	11.3	11.0	10.8	10.7
Industrial and Mining	7.2	7.2	7.1	6.9	7.0
	9.5	9.4	9.2	8.9	9.0

Average Retail Revenue per kWh Sold (excludes RES, DSM, ECA and LFCR)					
Average Revenue per Residential Customer	$1,077	$1,050	$1,045	$1,016	$1,035
Average kWh Sales per Residential Customer	10,383	10,341	10,583	10,566	10,696

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ENVIRONMENTAL MATTERS

Environmental Regulation

The Environmental Protection Agency (EPA) limits the amount of sulfur dioxide (SO2), nitrogen oxide (NOx), particulate matter, mercury and other emissions released into the atmosphere by power plants. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its customers.

Hazardous Air Pollutant Requirements

The Clean Air Act requires the EPA to develop emission limit standards for hazardous air pollutants that reflect the maximum achievable control technology. In February 2012, the EPA issued final rules to set the standards for the control of mercury emissions and other hazardous air pollutants from power plants.

Navajo

Based on the EPA's standards, Navajo may require mercury and particulate matter emission control equipment by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million for mercury control and about $43 million if the installation of baghouses to control particulates is necessary. The operator of Navajo is currently analyzing the need for baghouses under various regulatory scenarios, which will be affected by final Best Available Retrofit Technology (BART) rules when issued. TEP expects its share of the annual operating costs for mercury control and baghouses to be less than $1 million each.

San Juan

TEP expects San Juan's current emission controls to be adequate to comply with the EPA's final standards.

Four Corners

Based on the EPA's final standards, Four Corners may require mercury emission control equipment by 2015. TEP's share of the estimated capital cost of this equipment is less than $1 million. TEP expects its share of the annual operating cost of the mercury emission control equipment to be less than $1 million.

Springerville Generating Station

Based on the EPA's final standards, Springerville Generating Station (Springerville) may require mercury emission control equipment by 2015. The estimated capital cost of this equipment for Springerville Units 1 and 2 is about $5 million. TEP expects the annual operating cost of the mercury emission control equipment to be about $3 million. TEP will own 49.5% of Springerville Unit 1 upon close of the lease option purchases by early 2015; after the completion of such purchases, 50.5% of environmental costs attributed to Springerville Unit 1 will be reimbursed by third party owners.

Sundt Generating Station

TEP expects the final EPA standards will have little effect on capital expenditures at Sundt Generating Station (Sundt).

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 rules call for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. BART applies to plants built between August 1962 and August 1977. Because Navajo and Four Corners are located on the Navajo Indian Reservation, they are not subject to state oversight; the EPA oversees regional haze planning for these power plants.

Complying with the EPA's BART findings, and with other future environmental rules, may make it economically impractical to continue operating the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. TEP cannot predict the ultimate outcome of these matters.

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Navajo

In January 2013, the EPA proposed a BART determination that would require the installation of Selective Catalytic Reduction (SCR) technology on all three units at Navajo by 2023. In July 2013, SRP, along with other stakeholders including impacted government agencies, environmental organizations, and tribal representatives, submitted an agreement to the EPA that would achieve greater NOx emission reductions than the EPA's proposed BART rule. In September 2013, the EPA issued a supplemental proposal incorporating the provisions of the agreement as a better-than-BART alternative.

Among other things, the agreement calls for the shut-down of one unit or an equivalent reduction in emissions by 2020. The shutdown of one unit will not impact the total amount of energy delivered to TEP from Navajo. Additionally, the remaining Navajo participants would be required to install SCR or an equivalent technology on the remaining two units by 2030. As part of the agreement, the current owners have committed to cease their operation of conventional coal-fired generation at Navajo no later than December 2044. The Navajo Nation can continue operation after 2044 at its election. If SCR technology is ultimately implemented at Navajo, TEP estimates its share of the capital cost will be $42 million. Also, the installation of SCR technology at Navajo could increase the power plant's particulate emissions which may require that baghouses be installed. TEP estimates that its share of the capital expenditure for baghouses would be about $43 million. TEP's share of annual operating costs for SCR and baghouses is estimated at less than $1 million each. The EPA could issue their decision as early as mid-2014.

San Juan

In August 2011, the EPA issued a Federal Implementation Plan (FIP) establishing new emission limits for air pollutants at San Juan. These requirements are more stringent than those proposed by the State of New Mexico. The FIP requires the installation of SCR technology with sorbent injection on all four units to reduce NOx and control sulfuric acid emissions by September 2016. TEP estimates its share of the cost to install SCR technology with sorbent injection to be between $180 million and $200 million. TEP expects its share of the annual operating costs for SCR technology to be approximately $6 million.

In 2011, Public Service Company of New Mexico (PNM) filed a petition for review of, and a motion to stay, the FIP with the United States Court of Appeals for the Tenth Circuit (Tenth Circuit). In addition, the operator filed a request for reconsideration of the rule with the EPA and a request to stay the effectiveness of the rule pending the EPA's reconsideration and review by the Tenth Circuit. The State of New Mexico filed similar motions with the Tenth Circuit and the EPA. Several environmental groups were granted permission to join in opposition to PNM's petition to review in the Tenth Circuit. In addition, WildEarth Guardians filed a separate appeal against the EPA challenging the FIP's five-year implementation schedule. PNM was granted permission to join in opposition to that appeal. In March 2012, the Tenth Circuit denied PNM's and the State of New Mexico's motion for stay. Oral argument on the appeal was heard in October 2012.

In February 2013, the State of New Mexico, the EPA, and PNM signed a non-binding agreement (Settlement Agreement) that outlines an alternative to the FIP. The terms of the Settlement Agreement include: the retirement of San Juan Units 2 and 3 by December 31, 2017; the replacement by PNM of those units with non-coal generation sources; and the installation of Selective Non-Catalytic Reduction technology (SNCR) on San Juan Units 1 and 4 by January 2016 or later depending on the timing of EPA approvals. The New Mexico Environmental Department (NMED) prepared a revision to the regional haze State Implementation Plan (SIP) incorporating the provisions of the Settlement Agreement, and in September 2013, the New Mexico Environmental Improvement Board approved the SIP revision. The SIP revision now awaits final EPA approval. The EPA is expected to issue a final BART determination in the second or third quarter of 2014. TEP estimates its share of the cost to install SNCR technology on San Juan Unit 1 would be approximately $35 million. TEP's share of incremental annual operating costs for SNCR is estimated at $1 million. TEP owns 340 MW, or 50%, of San Juan Units 1 and 2. If San Juan Unit 2 is retired, TEP's coal-fired generating capacity would be reduced by 170 MW.

In connection with the implementation of the SIP revision and the retirement of San Juan Units 2 and 3, some of the San Juan owner participants (Participants) have expressed a desire to exit their ownership in the plant. As a result, the Participants are attempting to negotiate a restructuring of the ownership in San Juan, as well as addressing the obligations of the exiting Participants for plant decommissioning, mine reclamation, environmental matters, and certain ongoing operating costs, among other items. The Participants have engaged a mediator to assist in facilitating the resolution of these matters among the owners. The owners of the affected units also may seek approvals of their utility commissions or governing boards. We are unable to predict the outcome of the negotiations and mediation.

On October 17, 2013, the Tenth Circuit ruled on a motion filed by PNM for abatement of the pending petitions for review and seeking deferral of briefing on a simultaneously-filed motion to stay the FIP. The Tenth Circuit placed the pending petitions for

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review in abeyance and set a schedule for the parties to file status reports. The court ruled that, if at any time the Settlement Agreement is not implemented as contemplated, any party to the litigation may file a motion seeking to lift the abatement.

At December 31, 2013, the book value of TEP's share of San Juan Unit 2 was $113 million. If Unit 2 is retired early, we expect to request ACC approval to recover, over a reasonable time period, all costs associated with the early closure of the unit. TEP cannot predict the ultimate outcome of this matter.

Four Corners

In 2012, the EPA finalized the regional haze FIP for Four Corners. The final FIP requires SCR technology to be installed on all five units by 2017. In December 2013, APS (the operator) decided to shut down Units 1-3 and install SCRs on Units 4 and 5. Under this scenario, the installation of SCR technology can be delayed until July 2018. TEP's estimated share of the capital costs to install SCR technology on Units 4 and 5 is approximately $35 million. TEP's share of incremental annual operating costs for SCR is estimated at $2 million.

Springerville

The BART provisions of the Regional Haze Rules requiring emission control upgrades do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s which is after the time frame as designated by the rules. Other provisions of the Regional Haze Rule requiring further emission reduction are not likely to impact Springerville operations until after 2018.

Sundt

In July 2013, the EPA rejected the Arizona state implementation plan determination that Sundt Unit 4 is not subject to the BART provisions of the Regional Haze Rule and developed a timeline to issue a federal implementation plan for emissions sources including Sundt Unit 4. While TEP does not agree that Sundt Unit 4 is subject to BART, it submitted a better-than-BART proposal in November 2013 which called for the elimination of coal as a fuel source at Sundt by 2017. In January 2014, the EPA issued a BART proposal that would require TEP to either (i) install, by mid-2017, SNCR and other equipment 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. TEP estimates that the cost to install SNCR and other necessary equipment would be approximately $12 million, and the incremental annual operating costs would be $5 million to $6 million. Under the proposal, TEP would be required to notify the EPA of its decision by July 31, 2015. The EPA is expected to issue a final BART determination by July 2014. At December 31, 2013, the net book value of the Sundt coal handling facilities was $27 million. If the coal handling facilities are retired early, we expect to request ACC approval to recover, over a reasonable time period, all the remaining costs of the coal handling facilities.

Greenhouse Gas Regulation

In June 2013, President Obama directed the EPA to move forward with carbon emission regulations for both new and existing fossil-fueled power plants.

In January 2014, the EPA published a re-proposed rule for new power plants. UNS Energy does not anticipate that a final rule related to new fossil-fueled power plant sources will have a significant impact on operations.

For existing power plants, the President ordered the EPA to:

- propose carbon emission standards by June 1, 2014;
- finalize those standards by June 1, 2015; and
- require states to submit their implementation plans to meet the standards by June 30, 2016.

UNS Energy will continue to work with federal and state regulatory agencies to promote compliance flexibility in the rules impacting existing fossil-fuel fired power plants. We cannot predict the ultimate outcome of these matters.

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The table below provides a summary of the estimated impact of pending environmental regulations on TEP's annual O&M expense and capital expenditures.

Generating Facility	Estimated Annual O&M Expense	Estimated Capital Expenditures	Regulation (Compliance Date)	Upgrades
	Millions of Dollars			
Springerville Units 1 & 2[(1)]	$3	$5	MATS (2015)	Mercury Controls
San Juan Unit 1	1 - 6	35 - 200	Regional Haze/BART (2016)	SNCRs or SCRs
Navajo Units 1-3	3	86	MATS (2015) Regional Haze/BART (2030)	Mercury Controls; SCRs; Baghouses
Four Corners Units 4 & 5	3	36	MATS (2015) Regional Haze/BART (2018)	Mercury Controls; SCRs
Sundt Unit 4	5 - 6	12	Regional Haze (2017)	SNCR

(1) TEP will own 49.5% of Springerville Unit 1 upon close of the lease option purchases by early 2015; after the completion of such purchases, 50.5% of environmental costs attributed to Springerville Unit 1 will be reimbursed by third party owners.

Certain environmental costs and investments can be recovered by TEP through a retail rate mechanism, called the Environmental Cost Adjustor, that was approved in the 2013 TEP Rate Order. See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, TEP, Factors Affecting Results of Operations, 2013 TEP Rate Order.

Coal Combustion Residuals

In 2010, the EPA proposed a rule to regulate the handling and disposal of coal ash and other Coal Combustion Residuals (CCRs). The EPA has proposed regulating CCRs as either non-hazardous solid waste or hazardous waste. The hazardous waste alternative would require additional capital investments and operational costs for both storage and handling at plants and transportation to disposal locations. Both the hazardous waste and non-hazardous solid waste alternatives would require liners for new ash landfills or expansions to existing ash landfills. The rules will apply to CCRs produced by all of TEP's coal-fired generating assets. San Juan may also be subject to separate regulations being drafted by the Office of Surface Mining Reclamation and Enforcement because it disposes of CCRs in surface mine pits.

The EPA has not yet indicated a preference for regulating CCRs. Each option would allow CCRs to be beneficially reused or recycled as components of other products. We expect the EPA to issue a final rule in late 2014. TEP cannot predict the outcome of this matter.

UNS ELECTRIC

SERVICE TERRITORY AND CUSTOMERS

UNS Electric is a vertically integrated electric utility company serving approximately 93,000 retail customers in Mohave and Santa Cruz counties. These counties have a combined population of approximately 250,000. UNS Electric's annual retail customer growth rate was less than 1% from 2010 through 2013. We estimate that UNS Electric's retail customer base will increase by less than 1% in 2014. UNS Electric's customer base is primarily residential, with some commercial and industrial customers. Peak demand for 2013 was 423 MW.

POWER SUPPLY AND TRANSMISSION

Purchased Energy

UNS Electric relies on a portfolio of long, intermediate, and short-term power purchases to meet customer load requirements.

Generating Resources

UNS Electric owns and operates Black Mountain Generating Station (BMGS), a 90 MW gas-fired facility located near Kingman, Arizona. In July 2011, UNS Electric purchased BMGS from UED. UNS Gas purchases and transports natural gas to BMGS for UNS Electric under long-term natural gas transportation and sales agreements.

UNS Electric also owns and operates the Valencia Power Plant (Valencia), located in Nogales, Arizona. Valencia consists of four gas and diesel-fueled combustion turbine units and provides approximately 62 MW of peaking resources. The facility is directly interconnected with the distribution system serving the city of Nogales and the surrounding areas.

Renewable Energy Resources

UNS Electric agreed to purchase the output of a combined wind farm and solar generating facility located near Kingman. The above-market cost of energy purchased through the 20-year PPA will be recovered through the RES surcharge. For more information see Rates and Regulation, Renewable Energy Standard and Tariff below.

Future Generating Resources

Gila River Generating Station Unit 3

In December 2013, UNS Electric entered into an agreement to purchase 25% of Gila River Unit 3 (137 MW) for approximately $55 million, with TEP purchasing the remaining 75% interest (413 MW). The purchase price is subject to adjustments to prorate certain fees and expenses through the closing and in respect of certain operational matters. TEP and UNS Electric may also modify the percentage ownership allocation between them. We expect the transaction to close in December 2014.

The purchase of a 25% interest of Gila River Unit 3 would be consistent with UNS Electric's strategy to reduce its reliance on wholesale market purchases to meet retail customer demand.

See TEP, Generating and Other Resources, Future Generating Resources, Gila River Generating Station Unit 3, above, and Note 8.

Renewable Energy Resources

UNS Electric expects to invest approximately $7 million in 2014 in company-owned solar PV capacity. See Note 3.

Transmission

UNS Electric imports the power generated at BMGS into its Mohave County service territory over Western Area Power Administration's (WAPA) transmission lines. UNS Electric has transmission service agreements with WAPA for its transmission capacity that expire in June 2016.

UNS Electric imports the power generated at Valencia into its Santa Cruz County service territory over its own transmission lines.

Tucson to Nogales 138kV Transmission Line

UNS Electric completed construction of a 138kV transmission line from Tucson to Nogales at the end of 2013. This project replaces a 115kV transmission line that previously linked UNS Electric's load to the WAPA system. The new transmission line now connects UNS Electric's load in Nogales directly to TEP's high voltage transmission system. The connection to TEP's system eliminates a requirement to run local generation in Nogales that was required due to limitations on the WAPA system.

RATES AND REGULATION

2013 UNS Electric Rate Order

In December 2013, the ACC issued an order (2013 UNSE Rate Order) that resolved the rate case filed by UNSE in December 2012, which was based on a test year ended June 30, 2012. The 2013 UNSE Rate Order approved a $3 million non-fuel base rate increase and a new rate structure effective January 1, 2014. See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Electric, Factors Affecting Results of Operations, 2013 UNS Electric Rate Order.

Purchased Power and Fuel Adjustment Clause

The PPFAC, which is reset monthly, allows UNS Electric to recover its fuel, transmission, and purchased power costs, including demand charges, broker fees, and the prudent costs of contracts for hedging fuel and purchased power costs for its retail customers.

If the PPFAC bank balance becomes over collected by more than $10 million, UNS Electric must file for a PPFAC rate adjustment or justify why an adjustment is not necessary at this time. UNS Electric can request a surcharge to recover costs if

the PPFAC bank balance is under-collected. At December 31, 2013, the PPFAC bank balance was over-collected by $14 million on a billed-to-customer basis. See Note 3.

Renewable Energy Standard and Tariff

As part of a rate order issued in 2010, the ACC authorized UNS Electric to recover operating costs, depreciation, property taxes, and a return on its investment in company-owned solar projects through RES funds until these costs are reflected in its Base Rates.

In October 2013, the ACC approved UNS Electric's 2014 RES implementation plan. Under the plan, UNS Electric will collect approximately $6 million from customers during 2014 to fund the following: the above market cost of renewable energy purchases; incentives for customer installed distributed generation; a return on and of UNS Electric's investments in company-owned solar projects; and various other program costs. The plan includes approval for a UNS Electric investment of $7 million in 2014 for company-owned solar projects.

Energy Efficiency Standards

Since the implementation of the Electric EE Standards in 2010, UNS Electric saved cumulative annual energy equal to approximately 4.7% of retail kWh sales. See TEP, Rates and Regulation, Electric Energy Efficiency Standards, above.

The 2013 UNS Electric Rate Order approved a LFCR mechanism that will allow UNS Electric to recover certain non-fuel costs that would otherwise go unrecovered due to reduced kWh sales attributed to energy efficiency programs and distributed generation. See Item. 7-Management’s Discussion and Analysis of Financial Condition and Results of Operations, UNS Electric, Factors Affecting Results of Operations, 2013 UNS Electric Rate Order.

In December 2013, the ACC approved UNS Electric’s 2013-2014 Energy Efficiency implementation plan that included a 2014 calendar year budget to fund programs that support the ACC’s Electric EE Standards as well as a new performance incentive.

ENVIRONMENTAL MATTERS

UNS Electric is subject to environmental regulation of air and water quality, resource extraction, waste disposal, and land use by federal, state, and local authorities. UNS Electric believes that its facilities are in substantial compliance with all existing regulations and will be in compliance with expected environmental regulations. See Note 7.

UNS GAS

SERVICE TERRITORY AND CUSTOMERS

UNS Gas is a gas distribution company serving approximately 150,000 retail customers in Mohave, Yavapai, Coconino, Navajo, and Santa Cruz counties in Arizona. These counties comprise approximately 50% of the territory in the state of Arizona, with a population of approximately 700,000. UNS Gas’ customer base is primarily residential. Sales to residential customers provided approximately 61% of total revenues in 2013.

UNS Gas’ annual retail customer growth rate was less than 1% from 2010 through 2013. In 2014, we expect UNS Gas’ retail customer base to increase by less than 1%.

GAS SUPPLY AND TRANSPORTATION

UNS Gas directly manages its gas supply and transportation contracts. The market price for gas varies based upon the period during which the commodity is purchased and is affected by weather, production issues, the economy, and other factors. UNS Gas hedges its gas supply prices by entering into physical fixed price forward agreements and financial contracts in order to provide more stable prices to its customers. These purchases are made up to three years in advance with the goal of hedging at least 60% of the price of expected monthly gas consumption. UNS Gas hedged approximately 65% of its expected monthly consumption for the 2013/2014 winter season (November through March). Additionally, UNS Gas has approximately 60% of its expected gas consumption hedged for April through October 2014, and 40% hedged for the 2014/2015 winter season.

UNS Gas buys most of the gas it distributes from the San Juan Basin. The gas is delivered on the El Paso Natural Gas (EPNG) and Transwestern Pipeline Company (Transwestern) interstate pipeline systems under firm transportation agreements with combined capacity sufficient to meet UNS Gas’ customers’ demands.

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UNS Gas has average capacity rights of approximately 655,000 therms per day on the EPNG pipeline system, with an average of 1,095,000 therms per day in the winter season (November through March) to serve its service territories. UNS Gas has average capacity rights of 230,000 therms per day on the San Juan Lateral and Mainline of the Transwestern pipeline. The Transwestern pipeline principally delivers gas to the portion of UNS Gas' distribution system serving customers in Flagstaff and Kingman.

UNS Gas has a separate agreement with Transwestern for transportation capacity rights on the Phoenix Lateral Extension Line that expires in 2024. UNS Gas' average daily capacity right is 126,000 therms per day, with an average of 222,000 therms per day in the winter season.

See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Gas, Liquidity and Capital Resources, Contractual Obligations.

RATES AND REGULATION

2012 UNS Gas Rate Order

In April 2012, the ACC approved a Base Rate increase of $2.7 million as well as a partial decoupling mechanism to recover lost fixed cost revenues as a result of implementing the Gas Energy Efficiency Standards (Gas EE Standards). See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Gas, Factors Affecting Results of Operations, 2012 UNS Gas Rate Order.

Purchased Gas Adjustor

The PGA mechanism is intended to address the volatility of natural gas prices and allow UNS Gas to recover its actual commodity costs, including transportation, through a price adjustor. The difference between UNS Gas' actual monthly gas and transportation costs and the rolling 12-month average cost of gas and transportation is deferred and recovered or returned to customers through the PGA mechanism.

At any time UNS Gas' PGA balancing account, called the PGA bank balance, is under-recovered, UNS Gas may request a PGA surcharge with the goal of collecting the amount deferred from customers over a period deemed appropriate by the ACC. When the PGA bank balance reaches an over-collected balance of $10 million on a billed-to-customer basis, UNS Gas is required to make a filing with the ACC to determine how the over-collected balance should be returned to customers.

In October 2013, the ACC approved an increase to the existing customer PGA credit from 4.5 cents per therm to 10 cents per therm in order to reduce the over-collected PGA bank balance. The PGA credit will be effective for the period November 1, 2013 through April 30, 2014. At December 31, 2013, the PGA bank balance was over-collected by $10 million on a billed-to-customer basis.

Gas Energy Efficiency Standards and Decoupling

In 2010, the ACC approved Gas EE Standards which are designed to require UNS Gas and other affected utilities to implement cost-effective DSM programs. The Gas EE standards require increasing annual targeted retail therm savings equal to 6% by 2020. Since the implementation of the Gas EE Standards in 2010, UNS Gas' customers have saved cumulative energy equal to approximately 0.5% of total retail therm sales.

New and existing DSM programs, renewable energy technology that displaces gas, and certain energy efficient building codes are acceptable means to meet the Gas EE Standards. The Gas EE Standards provide for the recovery of costs incurred to implement DSM programs. UNS Gas' DSM programs and rates charged to retail customers for these programs are subject to ACC approval.

In June 2013, the ACC approved the UNS Gas 2011-2012 Gas Energy Efficiency implementation plan with modifications and amendments. The approval included an annual energy efficiency budget of approximately $2 million and a waiver of the Gas EE Standards through 2013.

ENVIRONMENTAL MATTERS

UNS Gas is subject to environmental regulation of air and water quality, resource extraction, waste disposal, and land use by federal, state, and local authorities. UNS Gas' facilities are in substantial compliance with existing regulations.

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EMPLOYEES (At December 31, 2013)

TEP had 1,398 employees, of which approximately 678 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 2013 and expires in January 2016.

UNS Electric had 143 employees, of which 27 employees were represented by the IBEW Local No. 387 and 87 employees were represented by the IBEW Local No. 769. The existing agreements with the IBEW Local No. 387 and No. 769 expire in February 2017 and June 2016, respectively.

UNS Gas had 188 employees, of which 109 employees were represented by IBEW Local No. 1116 and 5 employees were represented by IBEW Local No. 387. The agreements with the IBEW Local No. 1116 and No. 387 expire in June 2015 and February 2017, respectively.

SES had 248 employees, of which 216 are represented by IBEW Local No. 1116 and 19 by IBEW Local No. 570. These agreements expire in December 2014 and May 2016, respectively.

EXECUTIVE OFFICERS OF THE REGISTRANTS

Executive Officers – UNS Energy and TEP

Executive Officers of UNS Energy and TEP, who are elected annually by UNS Energy's Board of Directors and TEP's Board of Directors, are as follows:

Name	Age	Position(s) Held	Executive Officer Since
Paul J. Bonavia	62	Chairman and Chief Executive Officer	2009
David G. Hutchens	47	President and Chief Operating Officer	2007
Kevin P. Larson	57	Senior Vice President and Chief Financial Officer(1)	2000
Philip J. Dion III	45	Senior Vice President, Public Policy and Customer Solutions	2008
Kentton C. Grant	55	Vice President, Finance and Rates(2)	2007
Todd C. Hixon	47	Vice President and General Counsel	2011
Karen G. Kissinger	59	Vice President and Chief Compliance Officer	1991
Mark C. Mansfield	58	Vice President, Energy Resources	2012
Frank P. Marino	49	Vice President and Controller	2013
Thomas A. McKenna	65	Vice President, Energy Delivery	2007
Catherine E. Ries	54	Vice President, Human Resources and Information Technology	2007
Herlinda H. Kennedy	52	Corporate Secretary	2006

(1) Mr. Larson is also Treasurer at UNS Energy.
(2) Mr. Grant is also Treasurer at TEP.

Paul J. Bonavia	Mr. Bonavia has served as Chairman and Chief Executive Officer of UNS Energy and TEP since January 2009. He also served as President from January 2009 to December 2011. Prior to joining UNS Energy, Mr. Bonavia served as President of the Utilities Group of Xcel Energy. Mr. Bonavia previously served as President of Xcel Energy's Commercial Enterprises business unit and President of the company's Energy Markets unit.
David G. Hutchens	Mr. Hutchens has served as President and Chief Operating Officer of UNS Energy and TEP since August 2013. In December 2011 Mr. Hutchens was named President of UNS Energy and TEP. In March 2011, Mr. Hutchens was named Executive Vice President of UNS Energy and TEP. In May 2009, Mr. Hutchens was named Vice President of Energy Efficiency and Resource Planning. In January 2007, Mr. Hutchens was elected Vice President of Wholesale Energy at UNS Energy and TEP. Mr. Hutchens joined TEP in 1995.
Kevin P. Larson	Mr. Larson has served as Senior Vice President and Chief Financial Officer of UNS Energy and TEP since September 2005. Mr. Larson is also Treasurer of UNS Energy. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Treasurer in August 1994 and Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer.
Philip J. Dion III	Mr. Dion has served as Senior Vice President, Public Policy and Customer Solutions of UNS Energy and TEP since August 2013. Mr. Dion was named Vice President, Public Policy in April 2010. Mr. Dion joined UNS Energy in February 2008 as Vice President of Legal and Environmental Services. Prior to joining UNS Energy, Mr. Dion was chief of staff and chief legal advisor to Commissioner Marc Spitzer of the FERC. Mr. Dion previously worked in various roles at the ACC, including as an administrative law judge and as an advisor to Mr. Spitzer, prior to his appointment to the FERC.
Kentton C. Grant	Mr. Grant has served as Vice President of Finance and Rates of UNS Energy and TEP since January 2007. Mr. Grant also serves as Treasurer of TEP. Mr. Grant joined TEP in 1995.
Todd C. Hixon	Mr. Hixon has served as Vice President and General Counsel of UNS Energy and 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 UNS Energy and 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, most recently serving as Senior Director of Generation. Prior to joining TEP, Mr. Mansfield held various leadership positions at PacifiCorp Energy from 1992-2008.
Frank P. Marino	Mr. Marino has served as Vice President and Controller of UNS Energy and TEP since August 2013. Mr. Marino joined UNS Energy as Assistant Controller in January 2013. Prior to joining UNS Energy, he served 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 Nations Energy Corporation (a then wholly-owned subsidiary of Millennium) in 1998.
Catherine E. Ries	Ms. Ries has served as Vice President, Human Resources and Information Technology, since May 2013. Ms. Ries joined UNS Energy and TEP as Vice President of Human Resources in June 2007. Prior to joining UNS Energy, Ms. Ries worked for Clopay Building Products, a division of Griffon Corporation, from 2000 to 2007, and held the position of Vice President of Human Resources.

Herlinda H. Kennedy	Ms. Kennedy has served as Corporate Secretary of UNS Energy and TEP since September 2006. Ms. Kennedy joined TEP in 1980 and was named assistant Corporate Secretary in 1999.

SEC REPORTS AVAILABLE ON UNS ENERGY'S WEBSITE

UNS Energy and TEP make available their 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 they electronically file them with, or furnish them to, the Securities and Exchange Commission (SEC). These reports are available free of charge through UNS Energy's website address: http://www.uns.com. A link from UNS Energy's website to these SEC reports is accessible as follows: At the UNS Energy main page, select Investors from the menu shown at the top of the page; next select SEC filings from the menu shown on the Investor Relations page. UNS Energy's code of ethics, which applies to the Board of Directors and all officers and employees of UNS Energy and its subsidiaries, and any amendments or any waivers made to the code of ethics, is also available on UNS Energy's website.

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UNS Energy and TEP are providing the address of UNS Energy's website solely for the information of investors and do not intend the address to be an active link. Information contained at UNS Energy's website is not part of any report filed with the SEC by UNS Energy or TEP.

ITEM 1A. – RISK FACTORS

The business and financial results of UNS Energy and TEP are subject to a number of risks and uncertainties, including those set forth below and in other documents we file with the SEC. These risks and uncertainties fall primarily into six major categories: the proposed Merger, revenues, regulatory, environmental, financial, and operational.

RISKS RELATED TO THE PROPOSED MERGER WITH FORTIS

The Proposed Merger with Fortis May Not Be Completed.

The proposed Merger with Fortis requires approval by UNS Energy shareholders, the FERC, the Committee on Foreign Investment in the United States, and the ACC. Such approvals may not be obtained. For example, the ACC may not approve the Merger or may seek to impose conditions on the completion of the transaction, which could cause the conditions to the Merger to not be satisfied or which could delay or increase the cost of the transaction. In addition, the occurrence of a material adverse effect or the failure to satisfy other closing conditions could result in a termination of the Merger Agreement by Fortis.

Termination Fee

UNS Energy will be obligated to reimburse up to $12.5 million of Fortis' expenses if (i) Fortis or UNS Energy terminates the Merger Agreement because the acquisition has not been completed by December 11, 2014 (which may be extended under certain circumstances) or Fortis terminates the Merger Agreement based on a breach of the Merger Agreement by UNS Energy, and (ii) a competing proposal has been made or publicly disclosed and not withdrawn prior to the termination of the Merger Agreement or applicable breach. In addition, if within twelve months after such termination, a definitive agreement providing for an acquisition transaction is entered into, or an acquisition transaction is consummated by UNS Energy with, the person who made the acquisition proposal prior to such termination or applicable breach or with any other third party making an acquisition proposal within three months following such termination, UNS Energy will be obligated to pay Fortis a termination fee of approximately $64 million (less any expense reimbursement previously paid). In no event will more than one termination fee be payable.

Access to Capital and Market Value of UNS Energy Common Stock

Failure to complete the Merger could: (i) affect the value of UNS Energy's common stock, including by reducing it to a level at or below the trading range preceding the announcement of the Fortis transaction; and (ii) negatively affect our access to and cost of both equity and debt financing.

REVENUES

National and local economic conditions can negatively affect on the results of operations, net income, and cash flows at TEP, UNS Electric, and UNS Gas.

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 2009 through 2013 compared with average increases of approximately 2% in each year from 2004 to 2008. In 2013, total retail kWh sales were 0.2% above 2012 levels. 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.

Similar impacts were felt at UNS Electric and UNS Gas. Annual average increases in the number of retail customers at both companies remained below 1% in 2009 through 2013 compared with average annual growth rates of 3% from 2004 to 2008. We estimate that a 1% change in annual retail sales at UNS Electric and UNS Gas could impact pre-tax net income and pre-tax cash flows by approximately $1 million.

New technological developments and the implementation of new Energy Efficiency Standards will continue to have a significant impact on retail sales, which could negatively impact UNS Energy'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 and equipment. TEP and UNS

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Electric also are promoting DSM programs designed to help customers reduce their energy use, and these efforts will increase significantly under energy efficiency rules approved in 2010 by the ACC. Further development and use of these technologies and implementation of these rules would negatively impact the results of operations, net income, and cash flows of TEP and UNS Electric.

The revenues, results of operations, and cash flows of TEP, UNS Electric, and UNS Gas are seasonal, and are subject to weather conditions and customer usage patterns, which are beyond the companies' 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. UNS Electric's earnings follow a similar pattern, while UNS Gas' sales peak in the winter during home heating season. Cool summers or warm winters may reduce customer usage at all three companies, adversely affecting operating revenues, cash flows, and net income by reducing sales.

TEP and UNS Electric are 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 and UNS Electric sell electricity to mines, military installations, and other large industrial customers. In 2013, 35% of TEP's retail kWh sales, and 14% of UNS Electric's retail kWh sales, were to industrial and mining customers. Retail sales volumes and revenues from these customer classes could decline as a result of, among other things: economic conditions; 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 the energy needs. A reduction in retail kWh sales to TEP's and UNS Electric's large customers would negatively affect our results of operations, net income, and cash flows.

REGULATORY

TEP, UNS Electric, and UNS Gas are subject to regulation by the ACC, which sets the companies' Retail Rates and oversees many aspects of their business in ways that could negatively affect the companies' 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.

The ACC is charged with setting retail electric and gas rates that provide utility companies with an opportunity to recover their costs of service and earn a reasonable rate of return. As part of the ACC's process of establishing the retail electric and gas rates charged by TEP, UNS Electric and UNS Gas, the ACC could disallow the recovery of certain costs, such as: (i) the write-down of assets due to changes in federal regulations or due to applicable accounting rules; or (ii) any other expenses the ACC determines were not prudently incurred. The decisions made by the ACC on such matters impact the net income and cash flows of TEP, UNS Electric, and UNS Gas.

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

TEP, UNS Electric, and UNS Gas are 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. UNS Energy's electric utility subsidiaries are 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 prices.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power transmission systems, including TEP, are subject to mandatory transmission standards developed and enforced by NERC and subject to the oversight of 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

UNS Energy's utility subsidiaries are subject to numerous environmental laws and regulations that may increase their cost of operations or expose them 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 energy generation.

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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 for costly equipment upgrades by regulatory authorities.

We cannot provide assurance that existing environmental laws and regulations will not be revised or that new environmental laws and regulations will not 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 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 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.

New federal regulations to limit greenhouse gas emissions could increase TEP's cost of operations and result in a change in the composition of TEP's coal-dominated generating fleet.

Based on the finding by the EPA in December 2009 that emissions of greenhouse gases endanger public health and welfare, the agency is in the process of regulating greenhouse gas emissions. In addition, there are proposals and ongoing studies at the state, federal, and international levels to address global climate change that could also result in the regulation of CO_2 and other greenhouse gases. Any future regulatory actions taken to address global climate change represent a business risk to our operations. In 2013, 80% of TEP's total energy resources came from its coal-fueled generating facilities.

Reductions in CO_2 emissions to the levels specified by some proposals could be materially adverse to our financial position or results of operations if associated costs of control or limitation cannot be recovered from customers. Any future legislation or regulation addressing climate change could produce a number of other results including costly modifications to, or reexamination of the economic viability of, our existing coal plants; changes in the overall fuel mix of our generating fleet; or additional costs to fund energy efficiency activities. The impact of legislation or regulation to address global climate change would depend on the specific terms of those measures and cannot be determined at this time.

FINANCIAL

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.

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UNS Energy's net income and cash flows can be adversely affected by rising interest rates.
At December 31, 2013, TEP had $215 million of tax-exempt variable rate debt obligations, $50 million of which was hedged with a fixed-for-floating interest rate swap through September 2014. The interest rates are set weekly or monthly. The average interest rates ranged from 0.06% to 0.48% in 2013. 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 $2 million.
UNS Energy, TEP, UNS Electric, and UNS Gas also are subject to risk resulting from changes in the interest rate on their borrowings under revolving credit facilities. Revolving credit borrowings may be made on a spread over London Interbank Offer Rate (LIBOR) or an Alternate Base Rate. Each of these agreements is a committed facility and expires in November 2016.
If capital market conditions result in rising interest rates, the resulting increase in the cost of variable rate borrowings would negatively impact our results of operations, net income, and cash flows.
The expected purchase of Gila River and certain of TEP's leased assets, as well as the cost of significant investments in TEP's transmission system could require significant outlays of cash, which could be difficult to finance.
During 2013, TEP notified certain owner participants and their lessors that TEP elected to purchase their undivided ownership interests in Springerville Unit 1 upon the expiration of the lease term in January 2015. In total, TEP elected to purchase leased interests comprising 35.4% of Springerville Unit 1, representing 137 MW of capacity. In December 2014 and January 2015, TEP will be required to fund the purchase price of $65 million.
The Springerville Coal Handling Facilities can be purchased in April 2015 for a fixed price of $120 million. TEP also leases a 50% undivided interest in Springerville Common Facilities with primary lease terms ending in 2017 and 2021. Upon expiration of the Springerville Coal Handling and Common Facilities Leases (whether at the end of the initial term or any renewal term), TEP has the obligation under agreements with the owners of Springerville Units 3 and 4 to purchase such facilities. Upon acquisition by TEP, the owner of Springerville Unit 3 has the option and the owner of Springerville Unit 4 has the obligation to purchase from TEP a 14% interest in the Common Facilities and a 17% interest in the Coal Handling Facilities.
In December 2013, TEP and UNS Electric entered into a purchase agreement to acquire Unit 3 of the Gila River Generating Station (Gila River Unit 3). Gila River Unit 3 is a gas-fired combined cycle unit with a capacity rating of 550 MW. The transaction is expected to close in late 2014, upon which TEP and UNS Electric will be required to fund the purchase amount of $219 million.
In 2014 and 2015, TEP's capital expenditures related to investments in its high voltage transmission system are expected to be $147 million.
Debt levels, liquidity, regulatory rules, and other restrictions could limit the ability of TEP, UNS Electric, and UNS Gas to make distributions to UNS Energy.
As a holding company, UNS Energy has no operations of its own and derives all of its revenues and cash flow from its subsidiaries. TEP, UNS Electric, and UNS Gas could experience reduced levels of liquidity, or face other restrictions, which could adversely impact their ability to pay dividends to UNS Energy.
The debt levels at TEP, UNS Electric, and UNS Gas:

- require UNS Energy's subsidiaries to dedicate a substantial portion of their cash flow to pay principal and interest on their debt, which could reduce the funds available for working capital, capital expenditures, acquisitions, and other general corporate purposes; and
- could limit their ability to borrow additional amounts for working capital, capital expenditures, acquisitions, dividends, debt service requirements, execution of their business strategy, or other purposes.

TEP, UNS Electric, and UNS Gas may be required to post margin under their power and fuel supply agreements which could negatively impact their liquidity. The agreements under which we contract for power and fuel include requirements to post credit enhancement in the form of cash or letters of credit (LOCs) under certain circumstances, including changes in market prices which affect contract values, or a change in creditworthiness of the respective companies. In order to post such credit enhancement, TEP, UNS Electric, and UNS Gas would have to use available cash, draw under their revolving credit agreements, or issue LOCs under their revolving credit agreements.

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Regulatory rules and other restrictions include:
- TEP's, UNS Electric's, and UNS Gas' inability to lend to affiliates without ACC approval; and
- TEP, UNS Electric, and UNS Gas must be in compliance with their respective debt agreements to make dividend payments to UNS Energy.

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 or UNS Electric’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 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 or UNS Electric’s generating stations and transmission and distribution systems operate below expectations, TEP or UNS Electric’s operating results could be adversely affected.

The lack of access to sufficient supplies of water could have a material adverse impact on TEP’s business and results of operations.

Natural gas and coal-fired generating plants require continuous water supply for their operation. The region in which our power plants are located is prone to drought conditions, which could potentially affect the plants’ water supplies. Any material reduction in the water supply for such facilities would limit the ability of TEP and UNS Electric to produce and market electricity from such facilities and could have a material adverse impact on our results of operations. Further, any change in regulations or the level of regulation with regard to use, treatment and discharge of water, or the licensing of water rights in the jurisdictions where TEP and UNS Electric operate, could have a material adverse impact on our results of operations.

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.

The nature of our gas operations presents inherent risks of loss that could adversely affect our results of operations.

The operation of UNS Gas’ transmission and distribution systems involves certain risks, including gas leaks, fires, natural disasters, catastrophic accidents, explosions, pipeline ruptures, and other hazards and risks that may cause unforeseen interruptions, personal injury, or property damage. Any such incident could have an adverse effect on UNS Gas.

We may be subject to physical and/or cyber attacks.

As operators of critical energy infrastructure, we may face a heightened risk of physical and/or cyber attacks. Our electric generation, transmission, and distribution systems may be vulnerable to disability or failures as a result of physical or cyber acts of war or terrorism, vandalism or other causes.

Our corporate and information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes. 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 physical attack or cyber breach occurred, we could have our operations disrupted, property damaged, and customer information stolen; experience substantial loss of revenues, response costs, and

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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.

TEP or UNS Electric might not be able to secure adequate right-of-way to construct transmission lines and distribution-related facilities, and could be required to find alternate ways to provide adequate sources of energy and maintain reliable service for their customers.

TEP and UNS Electric rely on federal, state, and local governmental agencies to secure right-of-way and siting permits to construct transmission lines and distribution-related facilities. If adequate right-of-way and siting permits to build new transmission lines cannot be secured, TEP and UNS Electric may need to rely on more costly alternatives to provide energy to their customers, may not be able to maintain reliability in their service areas, or their ability to provide electric service to new customers may be negatively impacted.

ITEM 1B. – UNRESOLVED STAFF COMMENTS

None.

ITEM 2. – PROPERTIES

TEP PROPERTIES

Transmission facilities owned by TEP and by third parties, are located in Arizona and New Mexico and transmit the output from TEP's remote electric generating stations at Four Corners, Navajo, San Juan, Springerville, 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. TEP has arrangements with approximately 140 companies to interchange generation capacity and transmission of energy. See Item 1. Business, TEP, Generating and Other Resources.

At December 31, 2013, TEP owned or participated in an overhead electric transmission and distribution system consisting of:

- 564 circuit-miles of 500-kV lines;
- 1,088 circuit-miles of 345-kV lines;
- 413 circuit-miles of 138-kV lines;
- 481 circuit-miles of 46-kV lines; and
- 2,605 circuit-miles of lower voltage primary lines.

TEP's underground electric distribution system includes 4,442 cable-miles of lines. TEP owns approximately 77% of the poles on which its lower voltage lines are located. Electric substation capacity consists of 104 substations with a total installed transformer capacity of 14,879,950 kilovolt amperes.

The electric generating stations (except as noted below), administrative headquarters, warehouse and service center 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 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 long-term surface ownership agreement with the State of Arizona.

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,

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easements and leases for the plant, transmission lines and a water diversion facility located on land owned by the Navajo Nation. TEP also has acquired easements for transmission facilities related to San Juan, Four Corners, and Navajo across the Zuni, Navajo, and Tohono O'dham American Indian Reservations. TEP, in conjunction with PNM and Freeport McMoRan, 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.

TEP, under separate sale and leaseback arrangements, leases the following generation facilities (which do not include land):

- Springerville Coal Handling Facilities;
- a 50% undivided interest in the Springerville Common Facilities; and
- Springerville Unit 1 and the remaining 50% undivided interest in the Springerville Common Facilities.

See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, Tucson Electric Power Company, Factors Affecting Results of Operations, Springerville Unit 1 and Note 6.

UES PROPERTIES

At December 31, 2013, UNS Electric's transmission and distribution system consisted of approximately 60 circuit-miles of 138-kV transmission lines, 274 circuit-miles of 69-kV transmission lines, and 3,651 circuit-miles of underground and overhead distribution lines. UNS Electric also owns the 62 MW Valencia plant, the 90 MW BMGS, as well as 40 substations having a total installed capacity of 1,549,000 kilovolt amperes.

At December 31, 2013, UNS Gas' transmission and distribution system consisted of approximately 31 miles of steel transmission mains, 4,238 miles of steel and plastic distribution piping, and 138,951 customer service lines.

The gas and electric distribution and transmission facilities owned by UNS Electric and UNS Gas are located:

- on property owned by UNS Electric or UNS Gas;
- under or over streets, alleys, highways, and other places in the public domain, as well as national forests and state lands, under franchises, easements, or other rights which are generally subject to termination; or
- under or over private property as a result of easements obtained primarily from the record holder of title.

ITEM 3. – LEGAL PROCEEDINGS

Shareholder Lawsuits

Five putative shareholder class action lawsuits challenging the merger have been filed, four in the Superior Court of Pima County, Arizona: (i) Phillip Malenovshy v. UNS Energy Corporation, et al. (Case No. C20136942); (ii) Paul Parshall v. UNS Energy Corporation, et al. (Case No. C20136943); (iii) Hillary Kramer v. Paul J. Bonavia, et al. (Case No. C2014-0026); and (iv) Vandermeer Trust U/A DTD 03/11/1997 v. UNS Energy Corporation, et al. (Case No. C2014-0107); and one in federal court in the United States District Court for the District of Arizona: Milton Pfeiffer v. Paul J. Bonavia, et al. (Case No. 4:13-CV-02619-JGZ).

The lawsuits generally allege, among other things, that the directors of UNS Energy breached their fiduciary duties to shareholders of UNS Energy purportedly by agreeing to a transaction pursuant to an inadequate process and for failing to

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obtain the highest value for UNS Energy shareholders. The lawsuits allege that the Fortis entities also aided and abetted the directors of UNS Energy in the alleged breach of their fiduciary duties.

The lawsuits seek, in general, and among other things, (i) injunctive relief enjoining the transactions contemplated by the merger agreement, (ii) rescission or an award of rescissory damages in the event a merger is consummated, (iii) an award of plaintiffs' costs including reasonable attorneys' and experts' fees, (iv) an accounting by the defendants to plaintiffs for all damages caused by the defendants, and (v) such further relief as the court deems just and proper.

These lawsuits are at a preliminary stage. UNS Energy, its directors and the other defendants believe that these lawsuits are without merit and intend to defend against them vigorously.

Right of Way Matters

TEP previously reported it was a defendant in a class action filed in February 2009 in the United States District Court in Albuquerque, New Mexico by members of the Navajo Nation. The plaintiffs alleged, among other things, that the rights of way for defendants' transmission lines on Navajo lands were improperly granted and that the compensation paid for such rights of way was inadequate. The plaintiffs were requesting, among other things, that the transmission lines on these lands be removed. In March 2010, the court entered a final judgment dismissing the case. The plaintiffs filed a Notice of Appeal with the Bureau of Indian Affairs (BIA) in May 2010, appealing the BIA's decision to grant the rights of way that were the subject of the now-dismissed complaint. In June 2010, the BIA found that the Notice of Appeal failed to meet the minimum filing requirements. In September 2010, the plaintiffs filed new Notices of Appeal concerning the same rights of way. In August 2013, the Interior Board of Indian Appeals dismissed the plaintiffs' appeal for failure to meet procedural requirements. TEP cannot predict if the plaintiffs will again attempt to appeal the BIA's decision to grant the rights of way.

In addition, see legal proceedings discussed in Note 7.

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 COMMON EQUITY

Stock Trading

UNS Energy’s Common Stock is traded under the ticker symbol UNS and is listed on the New York Stock Exchange. On February 14, 2014, the closing price was $60.21 with 7,392 shareholders of record.

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

Dividends

UNS Energy

UNS Energy’s Board of Directors expects to continue to authorize the payment of regular quarterly cash dividends on our Common Stock; however, such dividends are subject to the Board’s evaluation of our financial condition, earnings, cash flows, and dividend policy.

The merger agreement with Fortis allows UNS Energy's Board of Directors to authorize quarterly dividends of up to $0.48 per share until the merger is completed, including a pro rata dividend determined by the number of days from the last declared record date to the date the merger is completed. See Item. 1- Business, Overview of Consolidated Businesses, Agreement and Plan of Merger.

On February 24, 2014, UNS Energy declared a first quarter cash dividend of $0.48 per share of Common Stock. The first quarter dividend, totaling approximately $20 million, will be paid March 25, 2014 to shareholders of record at the close of business March 13, 2014. The table below summarizes UNS Energy’s dividends paid in 2011 through 2013.

	2013	2012	2011
Quarterly Dividend Per Common Share	$0.435	$0.43	$0.42
Annual Dividend Per Common Share	$1.74	$1.72	$1.68
Common Stock Dividends Paid	$72 million	$70 million	$62 million

UNS Energy relies on dividends from its subsidiaries, primarily TEP, to declare and pay dividends to its shareholders.

TEP

TEP paid dividends to UNS Energy of $40 million in 2013 and $30 million in 2012. TEP did not pay any dividends to UNS Energy in 2011.

TEP can pay dividends if it maintains compliance with the TEP Credit Agreement and certain financial covenants. At December 31, 2013, TEP was in compliance with the terms of the TEP Credit Agreement.

UNS Electric

UNS Electric paid dividends to UNS Energy of $10 million in 2013 and 2012. UNS Electric did not pay any dividends to UNS Energy in 2011. UNS Electric’s ability to pay future dividends will depend on the cash needs for capital expenditures and various other factors.

The note purchase agreement for UNS Electric contains restrictions on dividends. UNS Electric may pay dividends so long as (a) no default or event of default exists and (b) it could incur additional debt under the debt incurrence test. At December 31, 2013, UNS Electric was in compliance with the terms of its note purchase agreement.

UNS Gas

UNS Gas paid dividends to UNS Energy of $10 million in 2013, $20 million in 2012, and $10 million in 2011. UNS Gas’ ability to pay future dividends will depend on the cash needs for capital expenditures and various other factors.

The note purchase agreement for UNS Gas contains restrictions on dividends. UNS Gas may pay dividends so long as (a) no default or event of default exists and (b) it could incur additional debt under the debt incurrence test. At December 31, 2013, UNS Gas was in compliance with the terms of its note purchase agreement.

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Other Non-Reportable Segments

Millennium paid dividends to UNS Energy of $1 million in 2013, $14 million in 2012 and $3 million in 2011.

UED did not pay any dividends to UNS Energy in 2013 or 2012. UED paid dividends to UNS Energy of $39 million in 2011, of which $28 million represented a return of capital.

See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Energy Consolidated, Liquidity and Capital Resources, Dividends on Common Stock.

Common Stock Dividends and Price Ranges

	2013			2012		
	Market Price per Share of Common Stock [1]		Dividends Declared	Market Price per Share of Common Stock [1]		Dividends Declared
Quarter:	High	Low		High	Low	
First	$49.13	$43.10	$0.435	$38.66	$35.83	$0.43
Second	51.54	42.51	0.435	38.86	35.20	0.43
Third	51.86	43.81	0.435	42.71	38.43	0.43
Fourth	60.02	45.30	0.435	43.56	39.02	0.43
Total			$1.74			$1.72

[1] UNS Energy's Common Stock price as reported by the New York Stock Exchange.

Convertible Senior Notes

See Note 6.

Issuer Purchases of Common Equity

UNS Energy did not purchase any shares of Common Stock during 2013, 2012, or 2011.

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ITEM 6. – SELECTED FINANCIAL DATA
UNS Energy

	2013	2012	2011	2010	2009
	In Thousands (Except per Share Data)				
Income Statement Data					
Operating Revenues	$1,484,560	$1,461,766	$1,478,702	$1,425,947	$1,396,606
Net Income	127,478	90,919	109,975	112,984	105,901
Basic Earnings Per Share	3.06	2.25	2.98	3.10	2.95
Diluted Earnings Per Share	3.04	2.20	2.75	2.86	2.73
Shares of Common Stock Outstanding:					
Weighted Average	41,618	40,362	36,962	36,415	35,858
End of Year	41,538	41,344	36,918	36,542	35,851
Cash Dividends Declared per Share	$1.74	$1.72	$1.68	$1.56	$1.16
Balance Sheet Data					
Total Utility Plant – Net	$3,534,837	$3,300,363	$3,182,263	$2,961,498	$2,785,714
Total Investments in Lease Debt and Equity	36,194	45,457	65,829	103,844	132,168
Other Investments and Other Property	34,971	36,537	34,205	61,676	60,239
Total Assets	4,273,069	4,140,429	3,989,279	3,796,246	3,615,211
Long-Term Debt	$1,507,070	$1,498,442	$1,517,373	$1,352,977	$1,307,795
Non-Current Capital Lease Obligations	149,767	262,138	352,720	429,074	488,349
Common Stock Equity	1,130,784	1,065,465	888,474	830,756	759,329
Total Capitalization	2,787,621	2,826,045	2,758,567	2,612,807	2,555,473
Cash Flow Data					
Net Cash Flows From Operating Activities	$420,512	$348,109	$337,320	$346,920	$347,310
Capital Expenditures	(325,886)	(307,277)	(374,122)	(330,629)	(294,020)
Net Cash Flows From Financing Activities	(135,742)	(37,682)	(1,441)	(51,183)	(28,916)
Ratio of Earnings to Fixed Charges [1]	2.77	2.30	2.43	2.62	2.46

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TEP

	2013	2012	2011	2010	2009
	Thousands of Dollars				
Income Statement Data					
Operating Revenues	$1,196,690	$1,161,660	$1,156,386	$1,125,267	$1,099,338
Net Income	101,342	65,470	85,334	108,260	90,688
Balance Sheet Data					
Total Utility Plant – Net	$2,944,455	$2,750,421	$2,650,652	$2,410,077	$2,261,325
Total Investments in Lease Debt and Equity	36,194	45,457	65,829	103,844	132,168
Other Investments and Other Property	33,488	35,091	32,313	43,588	31,813
Total Assets	3,556,060	3,461,046	3,277,661	3,078,411	2,924,108
Long-Term Debt	1,223,070	1,223,442	1,080,373	1,003,615	903,615
Non-Current Capital Lease Obligations	149,767	262,138	352,720	429,074	488,311
Common Stock Equity	925,923	860,927	824,943	709,884	650,591
Total Capitalization	2,298,760	2,346,507	2,258,036	2,142,573	2,042,517
Cash Flow Data					
Net Cash Flows From Operating Activities	$346,191	$267,919	$268,294	$302,483	$268,064
Capital Expenditures	(252,848)	(252,782)	(351,890)	(277,309)	(240,079)
Net Cash Flows From Financing Activities	(140,937)	11,987	51,452	(51,882)	(29,320)
Ratio of Earnings to Fixed Charges [(1)]	2.67	2.10	2.40	2.74	2.56

(1) 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.

See Item 7. – Management’s Discussion and Analysis of Financial Condition and Results of Operations.

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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 UNS Energy and its three primary business segments. It includes the following:

- outlook and strategies;
- operating results during 2013 compared with 2012, and 2012 compared with 2011;
- factors affecting our results and outlook;
- liquidity, capital needs, capital resources, and contractual obligations;
- dividends; and
- critical accounting estimates.

UNS ENERGY CORPORATION

UNS Energy is a utility services holding company engaged, through its primary subsidiaries, in the electric generation and energy delivery business. Each of UNS Energy’s subsidiaries is a separate legal entity with its own assets and liabilities. UNS Energy owns 100% of TEP and UES.

References to “we” and “our” are to UNS Energy and its subsidiaries, collectively.

OUTLOOK AND STRATEGIES

Agreement and Plan of Merger

In December 2013, UNS Energy entered into an Agreement and Plan of Merger with Fortis Parent, Fortis and Merger Sub. The Boards of Directors of each of UNS Energy and Fortis Parent have approved the Merger. At the completion of the Merger, each outstanding share of UNS Energy common stock will be converted into the right to receive $60.25 in cash and UNS Energy will become a wholly-owned subsidiary of Fortis.

The Merger is subject to the approval of stockholders holding a majority of the outstanding shares of UNS Energy and other customary closing conditions, including, among other things:

- the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended;
- approvals of the Arizona Corporation Commission and the Federal Energy Regulatory Commission;
- confirmation of review, without unresolved concerns, from the Committee on Foreign Investment in the United States; and
- the absence of any injunction, order or other law prohibiting the Merger.

On February 18, 2014, we filed definitive proxy materials with the SEC. We expect UNS Energy's shareholders to formally consider a proposal to approve the Merger Agreement at a meeting on March 26, 2014.

In January 2014, UNS Energy and Fortis Parent filed an application and supporting testimony with the ACC requesting approval of the Merger. The ACC administrative law judge (ALJ) assigned to this matter issued a procedural order that calls for settlement discussions to commence on April 28, 2014, and a hearing before the ALJ to commence on June 16, 2014. In February 2014, we filed an application with FERC requesting approval of the Merger. The Merger is expected to close by the end of 2014. If the Merger is completed, UNS Energy expects to record approximately $22 million of expenses related to the Merger in 2014.

Operating Plans and Strategies

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

- Completing the proposed Merger with Fortis including obtaining all necessary approvals;

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- Completing the purchases of Gila River Unit 3 and additional interests in Springerville Unit 1, which are both key components of our long-term diversification strategy for our generating portfolio. The focus of our resource strategy is to provide long-term rate stability for our customers, mitigate environmental impacts, comply with regulatory requirements, and leverage our existing utility infrastructure.
- Strengthening the underlying financial condition of our utility subsidiaries by achieving constructive regulatory outcomes, improving our capital structure and our credit ratings, and promoting economic development in our service territories.
- Developing strategic responses to new environmental regulations and potential new legislation, including potential limits on greenhouse gas emissions. 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 businesses.
- Focusing on our core utility businesses through operational excellence, investing in utility rate base, emphasizing customer service, and maintaining a strong community presence.
- Expanding TEP's and UNS Electric's portfolio of renewable energy resources and programs to meet Arizona's Renewable Energy Standard (RES) while creating ownership opportunities for renewable energy projects that benefit customers, shareholders, and the communities we serve.
- Developing strategic responses to Arizona's Energy Efficiency Standards that protect the financial stability of our utility businesses and provide benefits to our customers.

RESULTS OF OPERATIONS

Contribution by Business Segment

The table below shows the contributions to our consolidated net income by business segment:

	2013	2012	2011
	Millions of Dollars		
TEP	$101	$65	$85
UNS Electric	12	17	18
UNS Gas	11	9	10
Other Non-Reportable Segments and Adjustments [1]	3	—	(3)
Consolidated Net Income	$127	$91	$110

[1] Includes: UNS Energy parent company expenses; Millennium; UED; and inter-company eliminations.

Executive Overview

2013 Compared with 2012

TEP

TEP reported net income of $101 million in 2013 compared with net income of $65 million in 2012. The increase in net income is due in part to: a $41 million increase in retail margin revenues related to a non-fuel base rate increase that was effective on July 1, 2013 and higher retail kWh sales resulting from favorable weather conditions; a $2 million increase in the margin on long-term wholesale sales due to higher market prices for wholesale power; and a $9 million decrease in interest expense due in part to a reduction in capital lease obligation balances; partially offset by a $12 million increase in Base O&M due in part to planned and unplanned maintenance on TEP's generating facilities, as well as merger-related expenses of $6 million recorded in December 2013; and a $3 million increase in taxes other than income taxes due in part to an increase in property tax rates and higher asset balances.

Additionally, TEP's net income in 2013 includes an income tax benefit of $11 million. In June 2013, we recorded a regulatory asset and corresponding reduction of income tax expense of $11 million to recover previously recorded income tax expense through future rates as a result of the 2013 TEP Rate Order. The regulatory asset will be amortized as income tax expense as the qualifying assets are depreciated. See Note 9. TEP's 2013 results also include additional fuel expense of $3 million related to a one-time credit to customers resulting from the 2013 TEP Rate Order. TEP's results in 2012 reflect a $3 million reduction

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to pre-tax income due to an unplanned outage at Springerville Unit 3 and a $5 million write-off of transmission related assets. See Tucson Electric Power Company, Results of Operations.

UNS Electric

UNS Electric reported net income of $12 million in 2013 compared with net income of $17 million in 2012. The decrease in net income was due in part to lower mining kWh sales during 2013 and the loss of an industrial customer in the second half of 2012. See UNS Electric, Results of Operations.

UNS Gas

UNS Gas reported net income of $11 million in 2013 compared with net income of $9 million in 2012. The increase in net income is due primarily to: higher sales volumes resulting from cold weather, which contributed to an improvement in retail margin revenues; and a non-fuel base rate increase that was effective in May 2012. See UNS Gas, Results of Operations.

2012 Compared with 2011

TEP

TEP reported net income of $65 million in 2012 compared with $85 million in 2011. The decrease in net income was due primarily to: a $7 million decline in retail margin revenues resulting from lower retail kWh sales due to milder summer weather than 2011, as well as the effects of the ACC's energy efficiency and distributed generation requirements; an $8 million decline in long-term wholesale margin revenues resulting primarily from a change in the pricing of energy sold under the SRP wholesale contract that was effective on June 1, 2011; an $11 million increase in depreciation and amortization expense as a result of an increase in utility plant-in-service; and a $5 million decrease in pre-tax income related to the partial write-off of transmission-related assets. These factors were partially offset by a decrease in TEP's Base O&M, resulting primarily from fewer planned generating plant outages. Net income in 2011 included the recognition of a $7 million pre-tax gain related to the settlement of a dispute with El Paso Electric.
See Tucson Electric Power, Results of Operations.

UNS Electric and UNS Gas

UNS Electric reported net income of $17 million in 2012 compared with net income of $18 million in 2011. See UNS Electric, Results of Operations.

UNS Gas reported net income of $9 million in 2012 compared with net income of $10 million in 2011. See UNS Gas, Results of Operations.

Operations and Maintenance Expense

The table below summarizes the items included in UNS Energy's Operations and Maintenance (O&M) expense. In 2013, Base O&M includes merger-related expenses of $7 million.

	2013	2012	2011
	Millions of Dollars		
UNS Energy Base O&M (Non-GAAP)[(1)]	$288	$266	$271
Reimbursed Expenses Related to Springerville Units 3 and 4	70	72	63
Expenses Related to Customer-Funded Renewable Energy and Demand Side Management (DSM) Programs[(2)]	32	46	45
Total UNS Energy O&M (GAAP)	390	$384	$379

(1) Base O&M, a non-GAAP financial measure, should not be considered as an alternative to O&M, which is determined in accordance with generally accepted accounting principles (GAAP). We believe Base O&M provides useful information to investors because it represents the fundamental level of operating and maintenance expense related to our core business. Base O&M excludes expenses that are directly offset by revenues collected from customers and other third parties.

(2) Represents expenses related to customer-funded renewable energy and DSM programs; these expenses are being collected from customers and the corresponding amounts are recorded in retail revenue.

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LIQUIDITY AND CAPITAL RESOURCES

UNS Energy Consolidated Liquidity

Cash flows may vary during the year, with cash flow 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, UNS Energy will use, as needed, its revolving credit facility to assist in funding its business activities. The table below provides a summary of the liquidity position of UNS Energy and each of its segments:

Balances at December 31, 2013	Cash and Cash Equivalents	Borrowings under Revolving Credit Facility(1)	Amount Available under Revolving Credit Facility
	Millions of Dollars		
UNS Energy Stand-Alone	$9	$54	$71
TEP	25	1	199
UNS Electric(2)	5	22	48
UNS Gas(2)	33	—	70
Other(3)	3	N/A	N/A
Total	$75		

(1) Includes Letters of Credit (LOCs) issued under revolving credit facilities.

(2) Either UNS Gas or UNS Electric may borrow up to a maximum of $70 million; the total combined amount borrowed by both companies cannot exceed $100 million.

(3) Includes cash and cash equivalents at Millennium and UED.

In March 2014, TEP expects to issue a $15 million LOC to a subsidiary of Entegra to satisfy a condition of the Gila River Unit 3 purchase agreement. TEP's borrowing capacity under the TEP Credit Agreement will be reduced by $15 million until the Gila River transaction closes and the LOC is terminated.

Dividends from UNS Energy’s subsidiaries represent the parent company’s main source of liquidity.

Dividends from Subsidiaries

UNS Energy received $40 million in dividends from TEP and $10 million in dividends from each of UNS Electric and UNS Gas in 2013, and $1 million from Millennium. In 2012, UNS Energy received dividends of $30 million from TEP, $20 million from UNS Gas, $14 million from Millennium, and $10 million from UNS Electric.

Short-term Investments

UNS Energy’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, 2013, UNS Energy’s short-term investments included highly-rated and liquid money market funds and certificates of deposit.

Access to Revolving Credit Facilities

We have access to working capital through revolving credit agreements with lenders. Each of these agreements is a committed facility that expires in November 2016. The TEP Revolving Credit Facility and UNS Electric/UNS Gas Revolver may be used for revolving borrowings as well as to issue LOCs. TEP, UNS Electric, and UNS Gas each issue LOCs from time to time to provide credit enhancement to counterparties for their energy procurement and hedging activities. The UNS Credit Agreement also may be used to issue LOCs for general corporate purposes.

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. However, TEP will need to issue long-term debt or enter into additional short-term credit facilities by June 2014 to meet capital expenditure requirements and scheduled mid-year capital lease payments. See Item 7A Quantitative and Qualitative Disclosures about Market Risk.

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UNS Energy Consolidated Cash Flows

	Years Ended December 31,		
	2013	2012	2011
	Millions of Dollars		
Operating Activities	$421	$348	$337
Investing Activities	(334)	(263)	(327)
Financing Activities	(136)	(37)	(2)
Net Increase (Decrease) in Cash	(49)	48	8
Beginning Cash	124	76	68
Ending Cash	$75	$124	76

UNS Energy's operating cash flows are generated primarily by retail and wholesale energy sales at TEP, UNS Electric, and UNS Gas, net of the related payments for fuel and purchased power. Generally, cash from operations is lowest in the first quarter and highest in the third quarter due to TEP's summer-peaking load. TEP, UNS Electric, and UNS Gas typically use their revolving credit facilities to assist in funding their business activities during periods when sales are seasonally lower.

Capital expenditures at TEP, UNS Electric, and UNS Gas represent the primary use of cash for investing activities. Cash used for investing and financing activities can fluctuate year-to-year depending on: capital expenditures; repayments and borrowings under revolving credit facilities; debt issuances or retirements; capital lease payments by TEP; and dividends paid by UNS Energy to its shareholders.

Operating Activities

In 2013, net cash flows from operating activities were $73 million higher than they were in 2012. The following items affected the year-over-year change in operating cash flows: a $23 million increase in cash receipts from retail and wholesale sales, net of fuel and purchased power costs paid, due to a non-fuel base rate increase that became effective on July 1, 2013, an increase in sales volumes from warmer weather compared to 2012, and higher market prices for wholesale power; a $27 million decrease in operations and maintenance costs and wages paid, net of amounts capitalized, due in part to renewable prepayments made in 2012; and a $6 million decrease in interest paid on capital lease obligations due to a decline in the balance of capital lease obligations.

Investing Activities

Net cash flows used for investing activities increased $71 million in 2013 compared with 2012 due in part to: a $19 million increase in capital expenditures; a $17 million increase in REC purchases due to an increase in renewable energy PPAs; a $15 million decrease in proceeds from a note receivable; and a $10 million decrease in the return of investment in Springerville lease debt.

Capital Expenditures

	Actual	Estimated				
	2013	2014	2015	2016	2017	2018
	Millions of Dollars					
TEP	$253	$528	$469	$223	$276	$218
UNS Electric	56	95	39	33	37	49
UNS Gas	17	13	13	14	15	16
UNS Energy Consolidated	$326	$636	$521	$270	$328	$283

TEP's estimated capital expenditures include:

- $164 million for the purchase of 75% of Gila River Unit 3 in 2014;
- $65 million for the purchase of 35.4% of Springerville Unit 1 in 2014 and 2015, and $73 million for TEP's share of the expected purchase of interests in the Springerville Coal Handling facilities in April 2015;
- $147 million for TEP-related transmission investments during 2014 and 2015;

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- $35 million for TEP's share of potential environmental expenditures related to the installation of SNCR at San Juan Unit 1. See Item 1 Business, TEP, Environmental Matters and Note 7; and
- $38 million for TEP's share of the expected purchase of the Springerville Common Facilities upon the expiration of one of the two leases in 2017.

UNS Electric's estimated capital expenditures include the purchase of 25% of Gila River Unit 3 for approximately $55 million in 2014.

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. See Tucson Electric Power Company, Liquidity and Capital Resources, Investing Activities, Capital Expenditures.

Financing Activities

Net cash flows used for financing activities were $98 million higher in 2013 when compared with 2012 due to: a $10 million increase in scheduled capital lease payments; a $3 million increase in dividends paid on Common Stock; and the issuance of $150 million of long-term debt by TEP in 2012.

Capital Contributions

UNS Energy made no capital contributions to its subsidiaries in 2013 and 2012.

In 2011, UNS Energy contributed $20 million in capital to UNS Electric to help fund its purchase of BMGS from UED.

Also in 2011, UNS Energy contributed $30 million in capital to TEP to help fund the purchase of TEP's headquarters building.

See Tucson Electric Power Company, Liquidity and Capital Resources.

UNS Credit Agreement

The UNS Credit Agreement, which expires in November 2016, consists of a $125 million revolving credit and LOC facility. At December 31, 2013, there was $54 million outstanding at a weighted-average interest rate of 1.66%. The UNS Credit Agreement restricts additional indebtedness, liens, mergers, and sales of assets. The UNS Credit Agreement also requires UNS Energy to meet a minimum cash flow to debt service coverage ratio determined on a UNS Energy stand-alone basis. Additionally, UNS Energy cannot exceed a maximum leverage ratio determined on a consolidated basis. Under the terms of the UNS Credit Agreement, UNS Energy may pay dividends so long as it maintains compliance with the agreement. UNS Energy's obligations under the agreement are secured by a pledge of the common stock of Millennium, UES, and UED.

At December 31, 2013, we were in compliance with the terms of the UNS Credit Agreement.

Interest Rate Risk

UNS Energy is subject to interest rate risk resulting from changes in interest rates on its borrowings under the revolving credit facility. The interest paid on revolving credit borrowings is variable. UNS Energy may be required to pay higher rates of interest on borrowings under its revolving credit facility if LIBOR and other benchmark interest rates increase. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

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Contractual Obligations

The following chart displays UNS Energy’s consolidated contractual obligations by maturity and by type of obligation as of December 31, 2013:

UNS Energy Contractual Obligations								
Payment Due in Years Ending December 31,	2014	2015	2016	2017	2018	Thereafter	Other	Total
	Millions of Dollars							
Long-Term Debt								
Principal(1)	$—	$130	$132	$—	$100	$1,146	$—	$1,508
Interest(2)	67	66	61	60	61	480	—	795
Capital Lease Obligations(3)	214	69	17	18	11	30	—	359
Operating Leases	4	4	3	2	2	14	—	29
Purchase Obligations(4):								
Fuel(5)	103	83	80	75	49	345	—	735
Purchased Power	75	17	—	—	—	—	—	92
Transmission	7	13	12	12	11	27	—	82
Renewable Power Purchase Agreements (6)	36	37	37	37	37	485		669
RES Performance-Based Incentives(7)	9	9	9	9	9	85	—	130
Acquisition of Springerville Coal Handling & Common Facilities(8)	—	120	—	38	—	68	—	226
Other Long-Term Liabilities(9):								
Pension & Other Post Retirement Obligations(10)	17	6	6	6	6	33	—	74
Unrecognized Tax Benefits	—	—	—	—	—	—	4	4
Total Contractual Obligations	$532	$554	$357	$257	$286	$2,713	$4	$4,703

(1) Certain of TEP’s variable rate industrial development revenue bonds (IDBs) or pollution control revenue bonds are secured by LOCs issued pursuant to the TEP Credit Agreement, which expires in 2016, and the 2010 TEP Reimbursement Agreement, which expires in 2019. Although the $115 million of variable rate bonds mature between 2022 and 2032, the above maturity reflects a redemption or repurchase of such bonds as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement in 2016 (that supports $78 million of variable rate bonds) and the 2010 TEP Reimbursement Agreement in 2019 (that supports $37 million of variable rate bonds). Additionally, TEP's 2013 variable-rate IDBs, which mature in 2032, are subject to mandatory tender for purchase after the current five-year term and are therefore reflected as maturing in 2018. Excludes approximately $1 million of debt discount.

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

(3) Capital lease obligations include the purchase of Springerville Unit 1 in December 2014 and January 2015. See Note 6. Effective with commercial operation of Springerville Unit 3 in July 2006 and Unit 4 in December 2009, Tri-State and SRP are reimbursing TEP for various operating costs related to the common facilities on an ongoing basis, including a total of $14 million annually related to the Springerville Common and Springerville Coal Handling Facilities Leases. TEP remains the obligor under these capital leases, and Capital Lease Obligations do not reflect any reduction associated with this reimbursement.

(4) Excludes the acquisition of Gila River Unit 3 pending regulatory approvals. See Note 8.

(5) 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.

(6) TEP and UNS Electric have entered into 20-year PPAs with renewable energy generation producers to comply with the RES tariff. TEP and UNS Electric are obligated to purchase 100% of the output of these facilities. The

table above includes estimated future payments based on expected power deliveries under these contracts. TEP and UNS Electric have entered into additional long-term renewable PPAs to comply with the RES; however, TEP's and UNS Electric's obligations to accept and pay for electric power under these agreements does not begin until the facilities are operational.

(7) TEP and UNS Electric have 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 3.

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(8) TEP has agreed with the owners of Springerville Units 3 and 4 that, prior to expiration of the Springerville Coal Handling Facilities and Common Facilities Leases, TEP will either renew such leases or exercise its fixed price purchase option under such leases and acquire the leased facilities. TEP has the option of purchasing the facilities at the end of the initial lease term or after one or more renewal periods through 2025 for the Springerville Common Facilities and through 2035 for the Springerville Coal Handling Facilities. The table above reflects the purchase as if TEP exercised the fixed price purchase option at the end of the initial lease term. Upon such acquisitions by TEP, the owner of Springerville Unit 3 and the owner of Springerville Unit 4 have the obligation to purchase from TEP a 17% interest in the Springerville Coal Handling Facilities and a 14% interest in the Springerville Common Facilities.

(9) Excludes asset retirement obligations expected to occur through 2066.

(10) These obligations represent TEP's and UES' expected contributions to pension plans in 2014, TEP's expected benefit payments for its unfunded Supplemental Executive Retirement Plan (SERP), and TEP's expected retiree benefit costs to cover medical and life insurance claims as determined by the plans' actuaries. TEP and UES do not know and have not included pension and retiree benefit contributions beyond 2014 for their funded plans due to the significant impact that returns on plan assets and changes in discount rates might have on such amounts.

We have reviewed our contractual obligations and provide the following additional information:

- 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.
- None of our contracts or financing arrangements contains acceleration clauses or other consequences triggered by changes in our stock price.

Income Tax Position

The 2010 Federal Tax Relief Act and the American Taxpayer Relief Act of 2012 include provisions that make qualified property placed in service between 2010 and 2013 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 UNS Energy and TEP otherwise would have received over 20 years. As a result of these provisions, UNS Energy and TEP do not expect to pay any federal or state income taxes through 2017.

TUCSON ELECTRIC POWER COMPANY

RESULTS OF OPERATIONS

TEP's financial condition and results of operations are the principal factors affecting the financial condition and results of operations of UNS Energy. The following discussion relates to TEP, unless otherwise noted.

2013 compared with 2012

TEP reported net income of $101 million in 2013 compared with net income of $65 million in 2012. The following factors affected TEP's results in 2013:

- a $41 million increase in retail margin revenues due to a non-fuel base rate increase that was effective on July 1, 2013, $2 million of LFCR revenues recorded in the fourth quarter of 2013, and favorable weather during 2013 compared with the same period last year. Favorable weather conditions contributed to a 0.2% increase in retail kilowatt-hour (kWh) sales during 2013;
- a $2 million increase in the margin on long-term wholesale sales due in part to an increase in the market price for wholesale power;
- a $3 million increase in pre-tax income related to the operation of Springerville Units 3 and 4. An unplanned outage at Springerville Unit 3 negatively affected results in 2012;
- a $9 million decrease in interest expense due to a reduction in the balance of capital lease obligations;
- an $11 million tax benefit related to a regulatory asset recorded in June 2013 to recover previously recorded income tax expense through future rates as a result of the 2013 TEP Rate Order. See Note 9; and

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- a $5 million increase in pre-tax income as a result of the 2012 write-off of a portion of the planned Tucson to Nogales transmission line;

partially offset by

- a charge of $3 million recorded to fuel and purchased energy expense resulting from the 2013 TEP Rate Order. See Factors Affecting Results of Operations, Purchased Power and Fuel Adjustor Clause, below;
- a $12 million increase in Base O&M due in part to higher planned and unplanned generating plant maintenance expense, as well as merger-related expenses of $6 million recorded in December 2013; and
- a $3 million increase in taxes other than income taxes due in part to an increase in property tax rates and higher asset balances.

2012 compared with 2011

TEP reported net income of $65 million in 2012 compared with net income of $85 million in 2011. The following factors contributed to the decrease in TEP's net income:

- a $7 million decline in retail margin revenues resulting from lower retail kWh sales due to milder summer weather than 2011, as well as the effects of the ACC's energy efficiency and distributed generation requirements;
- an $8 million decline in long-term wholesale margin revenues resulting primarily from a change in the pricing of energy sold under the SRP wholesale contract effective June 1, 2011;
- a $3 million decrease in pre-tax income related to the operation of Springerville Units 3 and 4. An unplanned outage at Springerville Unit 3 negatively affected results in 2012;
- a $7 million pre-tax gain recorded in 2011 related to the settlement of a dispute with El Paso Electric;
- an $11 million increase in depreciation and amortization expense as a result of an increase in utility plant-in-service; and
- a $5 million decrease in pre-tax income as a result of the write-off of a portion of the planned Tucson to Nogales transmission line;

partially offset by

- a $4 million decrease in Base O&M primarily due to lower planned generating plant maintenance expense at San Juan.

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Utility Sales and Revenues

The table below provides a summary of TEP's retail kWh sales, revenues, and weather data during 2013, 2012, and 2011:

	2013	2012	Percent(1)	2011	Percent(1)
Energy Sales, kWh (in Millions):					
Electric Retail Sales:					
Residential	3,867	3,821	1.2 %	3,888	(1.7)%
Commercial(2)	2,187	2,187	— %	2,184	0.2 %
Industrial	2,114	2,132	(0.9)%	2,145	(0.6)%
Mining	1,079	1,093	(1.2)%	1,083	0.9 %
Other(2)	32	32	1.6 %	32	0.7 %
Total Electric Retail Sales	9,279	9,265	0.2 %	9,332	(0.7)%
Retail Margin Revenues (in Millions):					
Residential	$271	$248	9.3 %	252	(1.4)%
Commercial	181	171	5.9 %	170	0.5 %
Industrial	97	93	5.4 %	95	(2.5)%
Mining	34	30	11.5 %	32	(3.8)%
Other	2	2	5.9 %	2	(15.0)%
Total Retail Margin Revenues (Non-GAAP)(3)	585	544	7.7 %	551	(1.2)%
Fuel and Purchased Power Revenues	300	327	(8.1)%	307	6.5 %
RES, DSM, ECA and LFCR Revenues	49	45	6.8 %	46	(2.6)%
Total Retail Revenues (GAAP)	$934	$916	2.0 %	904	1.3 %
Average Retail Margin Rate (Cents / kWh):(1)					
Residential	7.02	6.50	8.0 %	6.48	0.3 %
Commercial	8.28	7.82	5.9 %	7.80	0.3 %
Industrial	4.61	4.33	6.5 %	4.42	(2.0)%
Mining	3.14	2.78	12.9 %	2.92	(4.8)%
Other	5.56	5.34	4.1 %	6.32	(15.5)%
Average Retail Margin Revenue	6.31	5.87	7.5 %	5.90	(0.5)%
Average Fuel and Purchased Power Revenue	3.24	3.52	(8.0)%	3.29	7.0 %
Average RES, DSM, ECA and LFCR Revenue	0.52	0.49	6.1 %	0.50	(2.0)%
Total Average Retail Revenue	10.07	9.88	1.9 %	9.69	2.0 %
Weather Data:					
Cooling Degree Days					
Year Ended December 31,	1,631	1,556	4.8 %	1,528	1.8 %
10-Year Average	1,491	1,484	NM	1,473	NM
Heating Degree Days					
Year Ended December 31,	1,449	1,201	20.6 %	1,597	(24.8)%
10-Year Average	1,404	1,394	NM	1,417	NM

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

(2) Retail kWh sales to commercial and other customers for 2012 and 2011 have been adjusted to reflect a change in the methodology for counting customers resulting from rate design changes from the 2013 TEP Rate Order.

(3) 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 to investors because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail

operating revenues available to cover the non-fuel operating expenses of our core utility business.

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2013 compared with 2012

Residential

Residential kWh sales were 1.2% higher in 2013 due in part to favorable weather conditions compared with 2012. A non-fuel base rate increase effective July 1, 2013 and higher sales volumes led to an increase in residential margin revenues of 9.3%, or $23 million. The average number of residential customers grew by 0.7% in 2013 compared with 2012.

Commercial

Commercial kWh sales were the same when compared with 2012. A non-fuel base rate increase effective July 1, 2013 contributed to an increase in commercial margin revenues of 5.9%, or $10 million.

Industrial

Industrial kWh sales decreased by 0.9% compared with 2012. Lower sales due to certain customers changing their usage patterns were more than offset by a non-fuel base rate increase effective July 1, 2013, which led to an increase in industrial margin revenues of $4 million.

Mining

Mining kWh sales decreased by 1.2% compared with 2012. One of TEP's mining customers performed maintenance on its facilities resulting in a temporary decrease in production. A non-fuel base rate increase effective July 1, 2013 led to an increase in margin revenues from mining customers of 11.5%, or $4 million. See Factors Affecting Results of Operations, Sales to Mining Customers.

2012 compared with 2011

Residential

In 2012, residential kWh sales decreased by 1.7% compared with 2011 due in part to a decrease in the number of Cooling Degree Days during the summer months of 2012 compared with 2011. Other factors affecting TEP’s 2012 retail sales volumes included the ACC’s Electric EE Standards and distributed generation requirements, as well as the pace of economic recovery.

Residential margin revenues in 2012 decreased by $4 million when compared with 2011.

Commercial

Commercial kWh sales increased by 0.1% compared with 2011 due primarily to a 0.4% increase in the number of commercial customers. Commercial margin revenues increased by less than $1 million, or 0.1%, compared with 2011.

Industrial

Industrial kWh sales decreased by 0.6% in 2012 compared with 2011, while margin revenues declined by 2.5%. The decline in margin revenues resulted from a change in usage patterns by certain industrial customers that reduced their demand charges paid to TEP.

Mining

The continuation of high copper prices led to increased mining activity, resulting in a 0.9% increase in sales volumes in 2012 compared with 2011. However, margin revenues from mining customers decreased by 3.8% compared with 2011, due to changing usage patterns which resulted in lower demand charges paid to TEP.

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Wholesale Sales and Transmission Revenues

	2013	2012	2011
	Millions of Dollars		
Long-Term Wholesale Revenues:			
Long-Term Wholesale Margin Revenues (Non-GAAP)(1)	$7	$5	$13
Fuel and Purchased Power Expense Allocated to Long- Term Wholesale Revenues	19	20	28
Total Long-Term Wholesale Revenues	26	25	41
Transmission Revenues	15	16	16
Short-Term Wholesale Revenues	92	70	73
Electric Wholesale Sales (GAAP)	$133	$111	$130

(1) Long-term Wholesale Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Electric Wholesale Sales, which is determined in accordance with GAAP. We believe the change in Long-Term Wholesale Margin Revenues between periods provides useful information to investors because it demonstrates the underlying profitability of TEP's long-term wholesale sales contracts. Long-Term Wholesale Margin Revenues represents the portion of long-term wholesale revenues available to cover the operating expenses of our core utility business.

Long-Term Wholesale Margin Revenues in 2013 were higher when compared with 2012 due in part to higher market prices for wholesale power. Long-Term Wholesale Margin Revenues in 2012 were lower when compared with 2011 due to a change in the pricing of energy sold under the SRP contract. See Factors Affecting Results of Operations, Long-Term Wholesale Sales, below.

Short-Term Wholesale Revenues

All revenues from short-term wholesale sales and 10% of the profits from wholesale trading activity are credited against the fuel and purchased power costs eligible for recovery in the PPFAC.

Other Revenues

	2013	2012	2011
	Millions of Dollars		
Revenue related to Springerville Units 3 and 4(1)	$102	$101	$97
Other Revenue	28	33	26
Total Other Revenue	$130	$134	$123

(1) Represents revenues and reimbursements from Tri-State and SRP, owners of Springerville Units 3 and 4, respectively, 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 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.

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Operating Expenses

Fuel and Purchased Power Expense

TEP's fuel and purchased power expense and energy resources for 2013, 2012 and 2011 are detailed below:

	Generation and Purchased Power			Fuel and Purchased Power Expense		
	2013	2012	2011	2013	2012	2011
	Millions of kWh			Millions of Dollars		
Coal-Fired Generation	10,254	9,702	9,946	$273	$247	$254
Gas-Fired Generation	1,007	1,435	929	46	65	55
Renewable Generation	38	45	28	—	—	—
Reimbursed Fuel Expense for Springerville Units 3 and 4	—	—	—	7	7	8
Total Fuel	11,299	11,182	10,903	326	319	317
Total Purchased Power	2,329	2,328	2,687	112	80	106
Transmission and Other PPFAC Recoverable Costs	—	—	—	12	6	(1)
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	—	(12)	31	(6)
Total Resources	13,628	13,510	13,590	$438	$436	$416
Less Line Losses and Company Use	(885)	(839)	(786)			
Total Energy Sold	12,743	12,671	12,804			

Generation

Total generating output increased in 2013 when compared with 2012 due in part to higher retail kWh sales than the same period last year. Coal-fired generation increased by 6% in 2013 when compared with 2012 due in part to the use of coal to fuel Sundt Unit 4 instead of natural gas.

The table below summarizes TEP's average cost per kWh generated or purchased:

	2013	2012	2011
	cents per kWh		
Coal	2.66	2.54	2.56
Gas	4.57	4.54	5.99
Purchased Power	4.83	3.44	3.94
All Sources	3.54	3.19	3.30

O&M

The table below summarizes the items included in TEP's O&M expense.

	2013	2012	2011
	Millions of Dollars		
Base O&M (Non-GAAP)(1)	$246	$234	$238
O&M Recorded in Other Expense	(7)	(6)	(8)
Reimbursed Expenses Related to Springerville Units 3 and 4	70	72	63
Expenses Related to Customer Funded Renewable Energy and DSM Programs(2)	26	35	38
Total O&M (GAAP)	$335	$335	$331

(1) Base O&M is a non-GAAP financial measure and should not be considered as an alternative to O&M, which is determined in accordance with GAAP. TEP believes that Base O&M, which is O&M less reimbursed expenses and expenses related to customer-funded renewable energy and DSM programs, provides useful information to investors because it represents the fundamental level of operating and maintenance expense related to our core business.

(2) Represents expenses related to customer-funded renewable energy and DSM programs; these expenses are being collected from customers and the corresponding amounts are recorded in retail revenue.

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The table below summarizes TEP’s pension and other retiree benefit expenses included in TEP's Base O&M in 2013, 2012, and 2011. See Note 10.

	2013	2012	2011
	Millions of Dollars		
Pension Expense Charged to O&M	$10	$10	$10
Retiree Benefit Expense Charged to O&M	5	5	4
Total	$15	$15	$14

FACTORS AFFECTING RESULTS OF OPERATIONS

2013 TEP Rate Order

In June 2013, the ACC issued an order (2013 TEP Rate Order) that resolved the rate case filed by TEP in July 2012, which was based on a test year ended December 31, 2011. The 2013 TEP Rate Order approved new rates effective July 1, 2013.

The provisions of the 2013 TEP Rate Order include, but are not limited to:

- an increase in non-fuel retail Base Rates of approximately $76 million over adjusted test year revenues;
- an Original Cost Rate Base (OCRB) of approximately $1.5 billion and a Fair Value Rate Base (FVRB) of approximately $2.3 billion;
- a return on equity of 10.0%, a long-term cost of debt of 5.18%, and a short-term cost of debt of 1.42%, resulting in a weighted average cost of capital of 7.26%;
- a capital structure of approximately 43.5% equity, 56.0% long-term debt, and 0.5% short-term debt;
- a 0.68% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $800 million);
- a revision in depreciation rates from an average rate of 3.32% to 3.0% for generation and distribution plant regulated by the ACC, primarily due to revised estimates of asset removal costs, which will have the effect of reducing depreciation expense by approximately $11 million annually; and
- an agreement by TEP to seek recovery of costs related to the Nogales transmission line from the Federal Energy Regulatory Commission (FERC) before seeking rate recovery from the ACC.

The 2013 TEP Rate Order also approved the following cost recovery mechanisms:

- A Lost Fixed Cost Recovery mechanism (LFCR) that allows TEP to recover certain non-fuel costs that would otherwise go unrecovered due to reduced kWh sales attributed to energy efficiency programs and distributed generation. The LFCR rate will be adjusted annually and is subject to ACC review and a year-over-year cap of 1% of TEP's total retail revenues. TEP expects to file its first LFCR report with the ACC on or before May 15, 2014. We expect the new LFCR rate to become effective on July 1, 2014. TEP’s 2015 LFCR report may include an estimated $6 million to $8 million of unrecovered non-fuel costs incurred during 2014. In the fourth quarter of 2013, TEP recorded LFCR revenues of $2 million for unrecovered non-fuel costs incurred during 2013.
- An Environmental Compliance Adjustor (ECA) mechanism that allows TEP to recover the costs of complying with environmental standards required by federal or other governmental agencies between rate cases. The ECA will be adjusted annually to recover environmental compliance costs and is subject to ACC approval and a cap of $0.00025 per kWh, which approximates 0.25% of TEP's total retail revenues. TEP expects to file its first ECA report on or before March 1, 2014. That report will include qualified investments and costs to be included in the ECA. TEP expects the new ECA rate to become effective on May 1, 2014. We estimate that the ECA could benefit pre-tax income by less than $1 million in 2014.
- An energy efficiency provision which includes a 2013 calendar year budget to fund programs that support the ACC's Electric Energy Efficiency Standards (Electric EE Standards), as well as a performance incentive. See Electric Energy Efficiency Standards, below.
- A new rate under TEP's PPFAC. See Purchased Power and Fuel Adjustment Clause, below.

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Competition

Retail Electric Competition Rules

In 1999, the ACC approved the Rules that provided a framework for the introduction of retail electric competition in Arizona. Certain portions of the ACC Rules that enabled Electric Service Providers (ESPs) to compete in the retail market were invalidated by an Arizona Court of Appeals decision in 2004. During 2012, several companies filed applications for a Certificate of Convenience and Necessity (CC&N) with the ACC to provide competitive retail electric services in TEP's service territory as an ESP. Unless and until the ACC clarifies the Rules and/or grants a CC&N to an ESP, it is not possible for TEP's retail customers to use an alternative ESP.

In May 2013, the ACC voted to commence a process to consider the possibility of opening Arizona to retail electric competition. The first step in the process was to solicit comments on questions raised by the ACC on the potential benefits and risks to Arizona electric customers associated with retail electric competition. In July 2013, various parties, including TEP and UNS Electric, filed comments. TEP and UNS Electric oppose opening Arizona to retail electric competition. Responsive comments from the parties were filed in August 2013. In September 2013, the ACC voted to close the docket and did not take any steps to implement retail electric competition. We cannot predict if the ACC will consider retail electric competition in the future.

Technological Developments and Energy Efficiency

New technological developments and the implementation of Electric EE Standards have reduced energy consumption by TEP's retail customers. TEP's customers also have the ability to install renewable energy technologies and conventional generation units that could reduce their reliance on TEP's services.

Coal-Fired Generating Resources

At December 31, 2013, approximately 70% of TEP's generating capacity was fueled by coal (of which 120 MW can be converted to 156 MW of natural gas capacity at Sundt Unit 4). Existing and proposed federal environmental regulations, as well potential changes in state regulation, may increase the cost of operating coal-fired generating facilities. TEP is evaluating various strategies for reducing the proportion of coal in its fuel mix. TEP's ability to reduce its coal-fired generating capacity will depend on several factors, including, but not limited to:

- the resolution of the non-binding agreement between the State of New Mexico, the EPA, and PNM as it relates to San Juan, see Note 7;
- TEP's future ownership interest in Springerville Unit 1, see Springerville Unit 1; and
- the potential purchase of a combined cycle natural gas plant, see Gila River Generating Station Unit 3.

Springerville Unit 1

TEP leases 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 are accounted for as capital leases. The leases expire in January 2015 and include fair market value renewal and purchase options. In 2006, TEP purchased a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 MW of capacity.

In 2011, TEP and the owner participants of Springerville Unit 1 completed a formal appraisal procedure to determine the fair market value purchase price of Springerville Unit 1 in accordance with the Springerville Unit 1 Leases. The purchase price was determined to be $478 per kW of capacity based on a capacity rating of 387 MW.

In August 2013, TEP notified certain owner participants and their lessors that TEP elected to purchase their undivided ownership interests in Springerville Unit 1, at the appraised value upon the expiration of the lease term in January 2015. In total, TEP elected to purchase leased interests comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million.

In October 2013, TEP agreed to purchase an additional 10.6% leased interest in Springerville Unit 1 for $20 million, the appraised value, with the purchase scheduled to occur in December 2014. The 10.6% ownership interest represents 41 MW of capacity.

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Upon the close of these lease option purchases, TEP will own 49.5% of Springerville Unit 1, or 192 MW of capacity. Due to TEP's purchase commitments, TEP and UNS Energy recorded an increase to both Utility Plant Under Capital Leases and Capital Lease Obligations on their balance sheets in the aggregate amount of approximately $55 million. TEP does not expect that its final undivided ownership interest in Springerville Unit 1 will exceed 49.5%, or 192 MW of capacity. The remaining 50.5% of Springerville Unit 1, or 195 MW of capacity, will be owned by third parties. TEP is not obligated to purchase any of the remaining power from Springerville Unit 1; however, TEP is obligated to operate Springerville Unit 1 for the remaining third-party owners following the expiration of the leases. TEP expects to replace the 195 MW of expiring leased capacity with the purchase of Gila River Unit 3. See Gila River Generating Station Unit 3, below.

Gila River Generating Station Unit 3

In December 2013, TEP and UNS Electric entered into an agreement (the Purchase Agreement) to purchase Gila River Unit 3 for $219 million from a subsidiary of Entegra. The purchase price is subject to adjustments to prorate certain fees and expenses through the closing and in respect of certain operational matters. It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 (413 MW) for approximately $164 million and UNS Electric will purchase the remaining 25% undivided interest (137 MW) for approximately $55 million, although TEP and UNS Electric may modify the percentage ownership allocation between them. We expect the transaction to close in December 2014.

The Purchase Agreement is subject to, among other things:

- the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended;
- the approval of the FERC;
- an amendment satisfactory to TEP, UNS Electric and the owners of the other units of the Gila River Power Station of the agreement with the other unit owners to address the ownership, operations and maintenance of common facilities and future generation located at the station;
- the completion of certain other agreements associated with the operation of Gila River Unit 3; and
- other customary closing conditions.

TEP expects to provide a letter of credit in March 2014 for $15 million to satisfy a condition of the Purchase Agreement. The seller of Gila River Unit 3 would be entitled to draw upon the letter of credit and apply such amount as liquidated damages if it has validly terminated the Purchase Agreement as a result of misrepresentations by TEP and UNS Electric or the failure of TEP and UNS Electric to close the transaction when the closing conditions have been satisfied. Upon the close of the transaction, the letter of credit would be canceled.

The purchase of Gila River Unit 3, which would replace the expiring coal-fired leased capacity from Springerville Unit 1 and the expected reduction of coal-fired generating capacity from San Juan Unit 2, is consistent with TEP's strategy to diversify its generation fuel mix. See Note 7.

In December 2013, UNS Electric filed an application requesting the ACC to approve an accounting order that would authorize UNS Electric to defer for future recovery specific non-fuel operating costs associated with its anticipated ownership of 25% of Gila River Unit 3. See UNS Electric, Factors Affecting Results of Operations, Gila River Generating Station Unit 3 and Note 8.

Springerville Units 3 and 4

TEP receives annual benefits in the form of rental payments and other fees and cost savings from operating Springerville Unit 3 on behalf of Tri-State and Unit 4 on behalf of SRP.

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The table below summarizes the income statement line items in which TEP records revenues and expenses related to Springerville Units 3 and 4:

	2013	2012	2011
	Millions of Dollars		
Other Revenues	$102	$101	$97
Fuel Expense	(7)	(7)	(8)
O&M Expense	(69)	(72)	(63)
Taxes Other Than Income Taxes	(2)	(1)	(2)

Long-Term Wholesale Sales

TEP’s two primary long-term wholesale contracts are with SRP and the Navajo Tribal Utility Authority (NTUA).

Salt River Project

From January 1, 2012, through the end of the contract in May 2016, SRP is required to purchase 500,000 MWh of on-peak energy per year. TEP does not receive a demand charge and the price of energy is based on a discount to the wholesale market price of on-peak power.

Navajo Tribal Utility Authority

TEP serves the portion of NTUA's load that is not served from NTUA's allocation of federal hydroelectric power. Over the last three years, sales to NTUA averaged 225,000 MWh. Prior to June 30, 2013, the power sold to NTUA was at a fixed price. In May 2013, TEP amended its contract with NTUA and extended the contract term from December 2015 to December 2022.

As a result of the amendment, on July 1, 2013, TEP began receiving monthly capacity payments in exchange for providing 15 MW from July to September (June to September beginning in 2014 and thereafter) and 50 MW for the remainder of each year. Starting in 2016, the July to September capacity increases to 25 MW. TEP prices the energy sold to NTUA at its monthly PPFAC eligible cost rate. Any energy sold in excess of the seasonal capacity amounts will be indexed to the wholesale market price of natural gas. TEP estimates that sales to NTUA will be approximately 225,000 MWh in 2014 and 2015.

Sales to Mining Customers

TEP's mining customers have indicated they are taking initial steps to increase production either through expansion of their current mining operations or by the re-opening of non-operational mine sites. If efforts to increase production are successful, TEP's mining load could increase by up to 100 MW over the next several years. The market price for copper and the ability to obtain necessary permits could affect the mining industry's expansion plans.

In addition to the mining customers that TEP currently serves, Augusta Resources Corporation filed a plan of operations with the United States Forest Service in 2007 for the proposed Rosemont Copper Mine near Tucson, Arizona. The Rosemont Copper Mine requires electric service from TEP via a 138 kilo-volt (kV) transmission line for the construction and ongoing operation of the mine. The state line siting committee approved a Certificate of Environmental Compatibility (CEC) in 2011 for the 138 kV transmission line. In 2012, the ACC finalized the CEC. If the Rosemont Copper Mine is constructed and reaches full production, it would be expected to become TEP's largest retail customer, with TEP serving the mine's estimated load of approximately 85 MW.

TEP cannot predict if or when existing mines will expand operations or new or re-opened mines will commence operations.

Interest Rates

TEP is exposed to interest rate risk resulting from changes in interest rates on certain of its variable rate debt obligations, as well as borrowings under its revolving credit facility. As a result, TEP may be required to pay significantly higher rates of interest on outstanding variable rate debt and borrowings under the TEP Revolving Credit Facility. At December 31, 2013, TEP had $215 million in tax-exempt variable rate debt outstanding. The interest rates on TEP’s tax-exempt variable rate debt are reset weekly or monthly. In 2013, the average rates paid ranged from 0.06% to 0.48%.

TEP has a fixed-for-floating interest rate swap to hedge $50 million of its tax-exempt variable rate debt.

TEP is also subject to interest rate risk resulting from changes in interest rates on its borrowings under the TEP Revolving Credit Facility. The interest paid on revolving credit borrowings is variable. If LIBOR and other benchmark interest rates

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increase, TEP may be required to pay higher rates of interest on borrowings under its revolving credit facility. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

LIQUIDITY AND CAPITAL RESOURCES

TEP Cash Flows

The tables below show TEP's net cash flows after capital expenditures, scheduled lease debt payments, and payments on capital lease obligations:

	2013	2012	2011
	Millions of Dollars		
Net Cash Flows – Operating Activities (GAAP)	$346	$268	$268
Less: Capital Expenditures	(253)	(253)	(352)
Net Cash Flows after Capital Expenditures (Non-GAAP)(1)	93	15	(84)
Less: Payments of Capital Lease Obligations	(100)	(89)	(74)
Plus: Proceeds from Investment in Lease Debt	9	19	38
Net Cash Flows after Capital Expenditures and Required Payments on Lease Debt and Capital Lease Obligations (Non-GAAP)(1)	$2	$(55)	$(120)

	2013	2012	2011
	Millions of Dollars		
Net Cash Flows – Operating Activities (GAAP)	$346	$268	$268
Net Cash Flows – Investing Activities (GAAP)	(260)	(228)	(312)
Net Cash Flows – Financing Activities (GAAP)	(141)	12	52
Net Increase (Decrease) in Cash	(55)	52	8
Beginning Cash	80	28	20
Ending Cash	$25	$80	$28

(1) Net Cash Flows after Capital Expenditures and Net Cash Flows after Capital Expenditures and Required Payments on Lease Debt and Capital Lease Obligations, both non-GAAP measures of liquidity, should not be considered as alternatives to Net Cash Flows—Operating Activities, which is determined in accordance with GAAP. We believe that Net Cash Flows after Capital Expenditures and Net Cash Flows after Capital Expenditures and Required Payments on Lease Debt and Capital Lease Obligations provide useful information to investors as measures of TEP’s ability to fund capital requirements, make required payments on lease debt and capital lease obligations, and pay dividends to UNS Energy before consideration of financing activities.

Liquidity Outlook

Cash flows may vary during the year, with cash flow 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, TEP will use, as needed, its revolving credit facility to assist in funding its business activities.

Additionally, due to capital expenditure requirements and scheduled mid-year lease payments, TEP will need to issue long-term debt or enter into additional short-term credit facilities by June 2014. Due to additional purchase commitments for Gila River Unit 3 and Springerville Unit 1, additional external financing will be needed by year-end 2014.

If the Merger Agreement is approved by all necessary parties, Fortis will contribute $200 million of equity capital to UNS Energy upon closing. If the contribution is made by December 2014, UNS Energy may then contribute this capital to TEP and UNS Electric to help fund the Gila River Unit 3 and Springerville Unit 1 purchase commitments.

Operating Activities

In 2013, net cash flows from operating activities were $78 million higher than in 2012. The increase was due primarily to: a $34 million increase in cash receipts from retail and wholesale sales, net of fuel and purchased power costs paid, resulting from a base rate increase that became effective on July 1, 2013, an increase in retail sales volumes, and an increase in wholesale power prices; a $30 million decrease in operations and maintenance costs paid due in part to lower renewable prepayments, lower incentive payments under DSM programs, and lower payments for remote plants; and a $6 million decrease in capital

lease interest paid due to a decline in capital lease obligation balances; partially offset by a $6 million increase in wages paid (net of amounts capitalized).

Investing Activities

Net cash flows used for investing activities increased by $32 million in 2013 compared with 2012 due primarily to: a $14 million increase in purchases of RECs due to an increase in renewable energy PPAs; and $10 million in lower proceeds from investment in lease debt.

TEP’s capital expenditures were $253 million in each of 2013 and 2012.

TEP's forecasted capital expenditures are summarized below:

	2014	2015	2016	2017	2018
	Millions of Dollars				
Transmission and Distribution	$135	$169	$84	$80	$81
Generation Facilities	109	101	63	83	61
Renewable Energy Generation	45	30	31	31	31
Springerville Lease Purchases(1)	20	119	—	38	—
Gila River Unit 3 Purchase	164	—	—	—	—
General and Other	55	50	45	44	45
Total	$528	$469	$223	$276	$218

(1) Includes: Springerville Unit 1 purchases of $65 million, $20 million in 2014, and $46 million in 2015; TEP's portion of the Springerville Coal Handling facilities purchase of $73 million in 2015; and Springerville Common facilities purchases of $38 million in 2017.

Financing Activities

In 2013, net cash from financing activities was $153 million lower than 2012. Financing activities in 2013 included a $10 million increase in dividend payments to UNS Energy and a $10 million increase in payments made on capital lease obligations. Financing activities in 2012 included: the issuance of $150 million of long-term debt; $7 million of repayments of long-term debt; and $10 million of repayments (net of borrowings) under the TEP Revolving Credit Facility.

TEP Mortgage Indenture

Prior to November 2013, the TEP Credit Agreement and the 2010 TEP Reimbursement Agreement were secured by $423 million in Mortgage Bonds issued under the 1992 Mortgage. As a result of a credit rating upgrade, in October 2013, TEP (i) requested $423 million in Mortgage Bonds be returned to TEP for cancellation, and (ii) discharged the 1992 Mortgage, which had created a lien on and security interest in substantially all of TEP’s utility plant assets. TEP’s obligations under the TEP Credit Agreement and the 2010 TEP Reimbursement Agreement are now unsecured. See Note 6.

TEP Credit Agreement

TEP Credit Agreement consists of a $200 million revolving credit, revolving LOC facility and an $82 million LOC facility to support tax-exempt bonds. The TEP Credit Agreement expires in November 2016.

In December 2013, TEP reduced its letter of credit facility from $186 million to $82 million, following the refinancing of $100 million of variable rate bonds and the cancellation of $104 million of LOCs supporting those bonds.

At December 31, 2013, there were no outstanding borrowings and $1 million of LOCs issued under the TEP Revolving Credit Facility.

In March 2014, TEP expects to issue a $15 million LOC to a subsidiary of Entegra to satisfy a condition of the Gila River Unit 3 purchase agreement. TEP's borrowing capacity under the TEP Credit Agreement will be reduced by $15 million until the Gila River transaction closes and the LOC is terminated.

The TEP Credit Agreement contains restrictions on mergers and sale of assets. The TEP Credit Agreement also requires TEP not to exceed a maximum leverage ratio. If TEP complies with the terms of the TEP Credit Agreement, TEP may pay dividends to UNS Energy. At December 31, 2013, TEP was in compliance with the terms of the TEP Credit Agreement. See Note 6.

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2010 TEP Reimbursement Agreement

In December 2010, TEP entered into a four-year $37 million reimbursement agreement (2010 TEP Reimbursement Agreement). A $37 million LOC was issued pursuant to the 2010 TEP Reimbursement Agreement. The LOC supports $37 million aggregate principal amount of variable rate tax-exempt pollution control bonds that were issued on behalf of TEP in December 2010.

In February 2014, TEP amended the 2010 TEP Reimbursement Agreement to extend the expiration date of the LOC from 2014 to 2019.

The 2010 TEP Reimbursement Agreement contains substantially the same restrictive covenants as the TEP Credit Agreement described above. At December 31, 2013, TEP was in compliance with the terms of the 2010 TEP Reimbursement Agreement. See Note 6.

2013 Bond Issuances and Redemptions

In March 2013, approximately $91 million of unsecured tax-exempt industrial development bonds were issued on behalf of TEP. The bonds bear interest at a fixed rate of 4.0%, mature in September 2029 and may be redeemed at par on or after March 1, 2023. In April 2013, the proceeds of the bond issuance were used to redeem approximately $91 million of tax-exempt bonds with an interest rate of 6.375% and a maturity date of September 2029. See Note 6.

In November 2013, $100 million of unsecured tax-exempt industrial development revenue bonds were issued on behalf of TEP and sold in a private placement. The bonds bear interest at a variable rate, mature in April 2032, and may be redeemed at any time while the bonds are in variable rate mode and upon proper notice by TEP. Also in November 2013, TEP entered into a Lender Rate Mode Covenants Agreement (2013 Covenants Agreement), with the purchaser of the bonds. The 2013 Covenants Agreement contains covenants and events of default which are the same, in all material respects, as those in the TEP Credit Agreement, including restrictions on mergers and sale of assets and requiring TEP not to exceed a maximum leverage ratio.

Under the terms of the 2013 Covenants Agreement, TEP may pay dividends to UNS Energy so long as it maintains compliance with the agreement. In December 2013, the proceeds of the bond issuance were used to redeem $100 million of variable rate tax-exempt bonds with a maturity date of December 2018. See Note 6.

Capital Lease Obligations

At December 31, 2013, TEP had $317 million of total capital lease obligations on its balance sheet. The table below provides a summary of the outstanding lease obligations:

Capital Leases	Capital Lease Obligation Balance As Of December 31, 2013	Expiration	Renewal/Purchase Option
	Millions of Dollars		
Springerville Unit 1[(1)]	$193	2015	Fair market value[(2)]
Springerville Coal Handling Facilities	28	2015	Fixed price purchase option of $120 million[(3)]
Springerville Common Facilities[(4)]	96	2017 and 2021	Fixed price purchase option of $106 million[(3)]
Total Capital Lease Obligations	$317		

(1) The Springerville Unit 1 Leases cover both Unit 1 and an undivided one-half interest in certain Springerville Common Facilities. The $193 million balance includes the present value of the lease purchase options elected and agreed to in August and October 2013. See Factors Affecting Results of Operations, Coal-Fired Generating Resources, Springerville Unit 1. Also see Note 6.

(2) As determined in December 2011 in an appraisal procedure undertaken pursuant to the Springerville Unit 1 lease agreements. TEP elected and agreed to purchase certain interests in the Springerville Unit 1 lease agreements in August and October 2013. See Factors Affecting Results of Operations, Coal-Fired Generating Resources, Springerville Unit 1. Also see Note 6.

(3)

TEP agreed with Tri-State, the lessee of Springerville Unit 3 and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities and Common Leases are not renewed, TEP will exercise the purchase options under these contracts. SRP will then be obligated to buy a portion of these facilities and Tri State will then be obligated to either 1) buy a portion of these facilities; or 2) continue making payments to TEP for the use of these facilities.

(4) The Springerville Common Facilities Leases cover an undivided one-half interest in certain Springerville Common Facilities.

TEP's capital lease obligation balances decline over time due to the normal capital lease payments made by TEP.

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Income Tax Position

See UNS Energy Consolidated, Liquidity and Capital Resources, Income Tax Position.

Contractual Obligations

The following chart displays TEP's contractual obligations by maturity and by type of obligation as of December 31, 2013:

	TEP Contractual Obligations							
Payment Due in Years Ending December 31,	2014	2015	2016	2017	2018	Thereafter	Other	Total
	Millions of Dollars							
Long-Term Debt								
Principal	$—	$—	$78	$—	$100	$ 1,046	$—	$1,224
Interest	54	53	54	53	54	443	—	711
Capital Lease Obligations	214	69	17	18	11	30	—	359
Operating Leases	3	3	2	2	2	14	—	26
Purchase Obligations(1):								
Fuel	77	63	64	62	36	285	—	587
Purchased Power	27	5	—	—	—	—	—	32
Transmission	3	6	6	6	6	21	—	48
Renewable Power Purchase Agreements	30	31	31	31	31	410		564
RES Performance-Based Incentives	8	8	8	8	8	83	—	123
Acquisition of Springerville Coal Handling and Common Facilities	—	120	—	38	—	68	—	226
Other Long-Term Liabilities:								
Pension & Other Post Retirement Obligations	15	6	6	6	6	33	—	72
Unrecognized Tax Benefits	—	—	—	—	—	—	2	2
Total Contractual Obligations	$431	$364	$266	$224	$254	$ 2,433	$2	$3,974

(1) Excludes the acquisition of Gila River Unit 3 pending regulatory approvals. See Note 8.

See UNS Energy Consolidated, Liquidity and Capital Resources, Contractual Obligations, for a description of these obligations.

We have reviewed our contractual obligations and provide the following additional information:

- The TEP 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. A downgrade in TEP's credit ratings would not cause a restriction in TEP's ability to borrow under its revolving credit facility.
- The TEP Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement contain certain financial and other restrictive covenants, including a leverage test. Failure to comply with these covenants would entitle the lenders to accelerate the maturity of all amounts outstanding. At December 31, 2013, TEP was in compliance with these covenants. See TEP Credit Agreement, above.
- 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 an 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, 2013, TEP had posted less than $1 million in LOCs as collateral with counterparties for credit enhancement.

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Dividends on Common Stock
TEP paid dividends to UNS Energy of $40 million in 2013 and $30 million in 2012. TEP did not pay any dividends to UNS Energy in 2011.
TEP can pay dividends to UNS Energy if it maintains compliance with the TEP Credit Agreement, the 2010 TEP Reimbursement Agreement and the 2013 Covenants Agreement. At December 31, 2013, TEP was in compliance with the terms of the TEP Credit Agreement, the 2010 TEP Reimbursement Agreement and the 2013 Covenants Agreement.

UNS ELECTRIC
RESULTS OF OPERATIONS
UNS Electric reported net income of $12 million in 2013, $17 million in 2012, and $18 million in 2011. The decline in net income in 2013 is related to a reduction in mining kWh sales as well as the loss of an industrial customer during the fourth quarter of 2012.
Like TEP, UNS Electric's operations are typically seasonal in nature, with peak energy demand occurring in the summer months. The table below provides summary financial information for UNS Electric:

	2013	2012	2011
	Millions of Dollars		
Retail Electric Revenues	$168	$171	$182
Wholesale Electric Revenues	6	17	6
Other Revenues	2	2	2
Total Operating Revenues	176	190	190
Purchased Energy Expense	7	81	91
Fuel Expense	76	10	7
Transmission Expense	13	11	12
Increase (Decrease) to Reflect PPFAC Recovery	(2)	(1)	(4)
O&M	32	31	27
Depreciation and Amortization Expense	19	18	17
Taxes Other Than Income Taxes	6	4	4
Total Other Operating Expenses	151	154	154
Operating Income	25	36	36
Other Income	1	—	—
Interest Expense	7	8	7
Income Tax Expense	7	11	11
Net Income	$12	$17	18

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The table below shows UNS Electric’s kWh sales and margin revenues:

	2013	2012	Percent[1]	2011	Percent[1]
Electric Retail Sales, kWh (in Millions):					
Residential	844	836	1.0 %	828	1.0 %
Commercial	607	614	(1.2)%	602	2.0 %
Industrial	185	213	(13.2)%	221	(3.5)%
Mining	61	91	(32.7)%	200	(54.8)%
Other	2	2	20.5 %	2	(1.7)%
Total Electric Retail Sales	1,699	1,756	(3.2)%	1,853	(5.3)%
Retail Margin Revenues (in Millions):					
Residential	$32	$32	0.9 %	$31	2.6 %
Commercial	28	29	(1.7)%	29	— %
Industrial	8	9	(14.4)%	9	— %
Mining	4	7	(34.4)%	7	(1.5)%
Other	—	—	— %	—	(33.3)%
Total Retail Margin Revenues (Non-GAAP)[2]	$72	$77	(4.8)%	$76	0.8 %
Fuel and Purchased Power Revenues	88	83	5.0 %	99	71.2 %
RES & DSM Revenues	8	11	(31.9)%	7	(15.9)%
Total Retail Revenues (GAAP)	$168	$171	(1.8)%	$182	(5.8)%
Weather Data:					
Cooling Degree Days					
Year Ended December 31,	3,278	3,489	(6.0)%	3,243	7.6 %
10-Year Average	3,271	3,285	NM	3,283	NM

(1) Percent change calculated on un-rounded data and may not correspond exactly to data shown in table.

(2) Total 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. Total Retail Margin Revenues exclude revenues collected from retail customers that are directly offset by expenses recorded in other line items. We believe the change in Total Retail Margin Revenues between periods provides useful information to investors because it demonstrates the underlying revenue trend and performance of our core utility business. Total Retail Margin Revenues represents the portion of retail operating revenues available to cover the non-fuel operating expenses of our core utility business.

In 2013, total retail kWh sales decreased by 3.2% and retail margin revenues decreased by 4.8% compared with 2012. The decline in sales volumes and resulting reduction in retail margin revenues is due primarily to one of UNS Electric's mining customers generating a portion of its own electricity and the loss of an industrial customer in the fourth quarter of 2012.

FACTORS AFFECTING RESULTS OF OPERATIONS

2013 UNS Electric Rate Order

In December 2012, UNS Electric filed a rate case application with the ACC as required by the ACC in UNS Electric's 2010 rate order. UNS Electric's rate filing was based on a test year ended June 30, 2012.

In December 2013, the ACC approved a new rate structure for UNS Electric that became effective on January 1, 2014 (2013 UNS Electric Rate Order). The provisions of the 2013 UNS Electric Rate Order include, but are not limited to:

- an increase in non-fuel retail Base Rates of approximately $3 million;
- an Original Cost Rate Base (OCRB) of approximately $213 million and a Fair Value Rate Base (FVRB) of approximately $283 million;

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- a return on equity of 9.50% and a long-term cost of debt of 5.97% resulting in a weighted average cost of capital of 7.83%;
- a 0.50% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $70 million); and
- a capital structure of 52.6% equity and 47.4% long-term debt.

The 2013 UNS Electric Rate Order also approved the following cost recovery mechanisms:

- an LFCR mechanism that will allow UNS Electric to recover certain non-fuel costs that would otherwise go unrecovered due to reduced kWh sales attributed to compliance with the ACC's Electric EE Standards and distributed generation requirements under the ACC's RES. The LFCR is not a full decoupling mechanism because it is not intended to recover lost fixed costs attributable to weather or economic conditions; and
- a Transmission Cost Adjustment Mechanism (TCA) that will allow more timely recovery of transmission costs associated with serving retail customers at the level approved by FERC. UNS Electric's approved Base Rates include a transmission component based on UNS Electric’s current FERC Open Access Transmission Tariff (OATT) rate. The OATT rates are adjusted annually and the TCA will be limited to the recovery (or refund) of costs associated with future changes in UNS Electric’s OATT rate. UNS Electric expects to make an informational TCA filing with the ACC on or before May 1, 2014. The filing will include an updated retail transmission rate calculated pursuant to UNS Electric's OATT rate.

Gila River Generating Station Unit 3

In December 2013, TEP and UNS Electric entered into an agreement to purchase Gila River Unit 3 for $219 million. It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 (413 MW) for approximately $164 million and UNS Electric will purchase the remaining 25% undivided interest (137 MW) for approximately $55 million, although TEP and UNS Electric may modify the percentage ownership allocation between them. We expect the transaction to close in December 2014. See Tucson Electric, Factors Affecting Results of Operations, Gila River Generating Station Unit 3 and Note 8.

Also in December 2013, UNS Electric filed an application requesting the ACC to approve an accounting order that would authorize UNS Electric to defer for future recovery specific non-fuel operating costs associated with Gila River Unit 3. If UNS Electric purchases 25% of Gila River Unit 3, the deferred costs, including depreciation, amortization, property taxes, O&M expense and a carrying cost on UNS Electric's investment in Gila River Unit 3, are expected to total approximately $9 million by the end of 2015. We cannot predict if the ACC will approve UNS Electric's request.

Competition

See Tucson Electric Power, Factors Affecting Results of Operations, Competition.

Fair Value Measurements

UNS Electric’s income statement exposure to risk is mitigated as UNS Electric reports the change in fair value of energy contract derivatives as a regulatory asset or a regulatory liability rather than in the income statement. See Note 15.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Outlook

UNS Electric expects operating cash flows to fund a portion of its construction expenditures during 2014. Additional sources of funding capital expenditures could include draws on the UNS Electric/UNS Gas Revolver, additional credit lines, the issuance of long-term debt, or capital contributions from UNS Energy.

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Cash Flows and Capital Expenditures

The table below provides summary cash flow information for UNS Electric:

	2013	2012	2011
	Millions of Dollars		
Cash Provided By (Used In):			
Operating Activities	$43	$50	$43
Investing Activities	(59)	(37)	(93)
Financing Activities	13	(10)	44
Net Increase/(Decrease) in Cash	(3)	3	(6)
Beginning Cash	8	5	11
Ending Cash	$5	$8	$5

Operating Activities

Cash provided by operating activities decreased by $7 million in 2013 when compared with 2012 due primarily to a $6 million decrease in cash receipts from electric sales (net of fuel and purchased energy costs paid) caused by a lower PPFAC rate effective in June 2012, the loss of an industrial customer, and lower mining sales volumes.

Investing Activities

UNS Electric had capital expenditures of $56 million in 2013 compared with $38 million in 2012. The increase is related to a transmission line that was constructed to increase reliability to UNS Electric's service territory in Nogales, Arizona.

Financing Activities

Cash provided by financing activities at UNS Electric in 2013 increased by $23 million when compared with 2012. Financing activities in 2013 included $22 million of borrowings under the UNS Electric/UNS Gas Revolver (net of repayments) and a $2 million receipt related to a contribution in aid of construction from a large customer.

UNS Electric/UNS Gas Credit Agreement

The UNS Electric/UNS Gas Credit Agreement consists of a $100 million unsecured revolving credit and revolving letter of credit facility. Either company can borrow up to a maximum of $70 million as long as the combined amount borrowed does not exceed $100 million. The UNS Electric/UNS Gas Credit Agreement expires November 2016. UNS Electric is only liable for UNS Electric’s borrowings, and similarly, UNS Gas is only liable for UNS Gas' borrowings under the UNS Electric/UNS Gas Credit Agreement.

The UNS Electric/UNS Gas Credit Agreement restricts additional indebtedness, liens, and mergers. It also requires each borrower not to exceed a maximum leverage ratio. Each borrower may pay dividends so long as it maintains compliance with the agreement. At December 31, 2013, UNS Electric and UNS Gas each were in compliance with the terms of the UNS Electric/UNS Gas Credit Agreement.

UNS Electric expects to draw upon the UNS Electric/UNS Gas Revolver from time to time for seasonal working capital purposes, to fund a portion of its capital expenditures or to issue LOCs to provide credit enhancement for its energy procurement and hedging activities. At December 31, 2013, UNS Electric had $22 million of outstanding borrowings and less than $1 million of LOCs issued under the UNS Electric/UNS Gas Credit Agreement.

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Contractual Obligations

UNS Electric Contractual Obligations								
Payment Due in Years Ending December 31,	2014	2015	2016	2017	2018	Thereafter	Other	Total
	Millions of Dollars							
Long-Term Debt								
Principal	$—	$80	$—	$—	$—	$ 50	$—	$130
Interest	7	7	4	4	4	17	—	43
Purchase Obligations[1]:								
Purchased Power	48	12	—	—	—	—	—	60
Transmission	4	7	6	6	5	6	—	34
Renewable Power Purchase Agreements	6	6	6	6	6	75	—	105
RES Performance-Based Incentives	1	1	1	1	1	2		7
Other Long-Term Liabilities:								
Pension & Other Post Retirement Obligations	1	—	—	—	—	—	—	1
Unrecognized Tax Benefits	—	—	—	—	—	—	2	2
Total Contractual Obligations	$67	$113	$17	$17	$16	$ 150	$2	$382

[1] Excludes the acquisition of Gila River Unit 3 pending regulatory approvals. See Note 8.

See UNS Energy Consolidated, Liquidity and Capital Resources, Contractual Obligations, for a description of these obligations.

Dividends on Common Stock

UNS Electric paid dividends to UNS Energy, through UES, of $10 million in both 2013 and 2012. UNS Electric did not pay any dividends to UNS Energy in 2011. UNS Electric’s ability to pay future dividends will depend on the cash needs for capital expenditures and various other factors.

The note purchase agreement for UNS Electric contains restrictions on dividends. UNS Electric may pay dividends so long as (i) no default or event of default exists, and (ii) it could incur additional debt under the debt incurrence test. At December 31, 2013, UNS Electric was in compliance with the terms of its note purchase agreement and the terms of the UNS Electric/UNS Gas Revolver.

UNS GAS

RESULTS OF OPERATIONS

UNS Gas reported net income of $11 million in 2013, $9 million in 2012, and $10 million in 2011. The increase in net income in 2013 is due primarily to an improvement in retail margin revenues caused by cold weather in the first and fourth quarters, which contributed to an increase retail therm sales, as well as a non-fuel base rate increase that was effective in May 2012.

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The table below provides summary financial information for UNS Gas:

	2013	2012	2011
	Millions of Dollars		
Gas Revenues	$131	$128	$148
Other Revenues	3	5	3
Total Operating Revenues	134	133	151
Purchased Gas Expense	73	72	85
Increase (Decrease) to Reflect PGA Recovery Treatment	(2)	2	5
O&M	26	25	25
Depreciation and Amortization	9	9	8
Taxes Other Than Income Taxes	4	4	4
Total Other Operating Expenses	110	112	127
Operating Income	24	21	24
Interest Expense	6	6	7
Income Tax Expense	7	6	7
Net Income	$11	$9	$10

The table below includes UNS Gas' therm sales and margin revenues:

	2013	2012	Percent[(1)]	2011	Percent[(1)]
Gas Retail Sales, Therms (in Millions):					
Residential	76	67	12.7 %	74	(9.1)%
Commercial	31	29	7.2 %	31	(5.7)%
All Other	9	8	13.1 %	9	(13.5)%
Total Gas Retail Sales	116	104	11.2 %	114	(8.5)%
Negotiated Sales Program (NSP)	27	32	(15.2)%	26	21.2 %
Total Gas Sales	143	136	5.1 %	140	(3.0)%
Retail Margin Revenues (in Millions):					
Residential	$42	$38	9.7 %	$40	(3.5)%
Commercial	12	11	7.4 %	11	0.9 %
All Other	2	2	14.3 %	2	(4.5)%
Total Retail Margin Revenues (Non-GAAP)[(2)]	56	51	9.4 %	53	(2.7)%
DSM Revenue	1	1	(18.2)%	1	— %
Transport and NSP	17	16	6.3 %	17	(4.2)%
Retail Fuel Revenues	57	60	(4.5)%	77	(22.5)%
Total Gas Revenues (GAAP)	$131	$128	2.3 %	$148	(13.2)%
Weather Data:					
Heating Degree Days					
Year Ended December 31,	4,588	4,089	12.2 %	4.615	(11.4)%
10-Year Average	4,401	4,431	NM	4,399	NM

(1) Percent change calculated on un-rounded data and may not correspond exactly to data shown in table.

(2) Total Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Gas Revenues, which is determined in accordance with GAAP. Total Retail Margin Revenues excludes revenues collected from retail customers that are directly offset by expenses recorded in other line items. We believe the change in Total Retail Margin Revenues between periods provides useful information to investors because it demonstrates the underlying revenue trend and performance of our core utility business. Total Retail Margin Revenues represents the portion of retail operating revenues available to cover the non-fuel operating expenses of our core utility business.

Retail therm sales in 2013 increased by 11.2% when compared with 2012 due to a 12.2% increase in Heating Degree Days. The increase in retail therm sales, as well as a Base Rate increase implemented in May 2012, contributed to an increase in retail margin revenues of 9.4%, or $5 million, when compared with 2012.

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FACTORS AFFECTING RESULTS OF OPERATIONS

Competition

New technological developments and the implementation of the ACC's Gas Energy Efficiency Standards (Gas EE Standards) may reduce energy consumption by UNS Gas' retail customers. Customers of UNS Gas also have the ability to switch from gas to an alternate energy source that could reduce their reliance on services provided by UNS Gas.

2012 UNS Gas Rate Order

In April 2012, the ACC approved a Base Rate increase of $2.7 million as well as a LFCR mechanism to enable UNS Gas to recover lost fixed-cost revenues as a result of implementing the Gas EE Standards. The LFCR is expected to recover lost fixed-cost revenues of less than $0.1 million in 2014, based on estimated lost retail therm sales from May 2012 through December 2013.

The new rates became effective on May 1, 2012. The impact of the Base Rate increase on customers' bills was offset by a temporary credit adjustment to the PGA. See Purchased Gas Adjustor.

Fair Value Measurements

UNS Gas' income statement exposure to risk is mitigated as UNS Gas reports the change in fair value of energy contract derivatives as a regulatory asset or a regulatory liability rather than in the income statement. See Note 15.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Outlook

UNS Gas expects operating cash flows to fund all of its construction expenditures during 2014. If natural gas prices rise and UNS Gas is not allowed to recover its projected gas costs or PGA bank balance on a timely basis, UNS Gas may require additional funding to meet operating and capital requirements in future periods. Sources of funding future capital expenditures could include existing cash balances, draws on the UNS Electric/UNS Gas Revolver, additional credit lines, the issuance of long-term debt, or capital contributions from UNS Energy.

Cash Flows and Capital Expenditures

The table below provides summary cash flow information for UNS Gas:

	2013	2012	2011
	Millions of Dollars		
Cash Provided By (Used In):			
Operating Activities	$27	$28	$32
Investing Activities	(15)	(15)	(12)
Financing Activities	(10)	(20)	(11)
Net Increase/(Decrease) in Cash	2	(7)	9
Beginning Cash	31	38	29
Ending Cash	$33	$31	$38

UNS Gas' operating cash flows during 2013 were $1 million lower than 2012 due in part to the PGA credit that was effective in April 2012.

UNS Electric/UNS Gas Credit Agreement

At December 31, 2013, UNS Gas had no outstanding borrowings under the UNS Electric/UNS Gas Credit Agreement. See UNS Electric, Liquidity and Capital Resources, UNS Electric/UNS Gas Credit Agreement.

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Interest Rate Risk

UNS Gas is subject to interest rate risk resulting from changes in interest rates on its borrowings under its revolving credit facility. The interest paid on revolving credit borrowings is variable. If LIBOR or other benchmark interest rates increase, UNS Gas may be required to pay higher rates of interest on borrowings under its revolving credit facility. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Contractual Obligations

The following table displays UNS Gas' contractual obligations as of December 31, 2013 by maturity and by type of obligation:

	UNS Gas Contractual Obligations							
Payment Due in Years Ending December 31,	2014	2015	2016	2017	2018	Thereafter	Other	Total
	Millions of Dollars							
Long-Term Debt								
Principal	$—	$50	$—	$—	$—	$ 50	$—	$100
Interest	6	6	3	3	3	20	—	41
Operating Leases	1	1	1	—	—	—	—	3
Purchase Obligations:								
Fuel	26	20	16	13	13	60	—	148
Other Long-Term Liabilities:								
Pension & Other Post Retirement Obligations	1	—	—	—	—	—	—	1
Total Contractual Obligations	$34	$77	$20	$16	$16	$ 130	$—	$293

Dividends on Common Stock

UNS Gas paid dividends to UNS Energy, through UES, of $10 million 2013, $20 million in 2012, and $10 million in 2011. UNS Gas' ability to pay future dividends will depend on the cash needs for capital expenditures and various other factors.

The note purchase agreement for UNS Gas contains restrictions on dividends. UNS Gas may pay dividends so long as (i) no default or event of default exists, (ii) it could incur additional debt under the debt incurrence test. At December 31, 2013, UNS Gas was in compliance with the terms of its note purchase agreement and had sufficient additional debt under the debt incurrence test to pay dividends.

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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 UNS Energy's other significant accounting policies can be found in Note 1.

Accounting for Regulated Operations

We account for our regulated electric and gas 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, 2013, regulatory liabilities net of regulatory assets totaled $103 million at TEP, $9 million at UNS Electric and $40 million at UNS Gas. There are no current or expected proposals or changes in the regulatory environment that impact our ability to apply regulated operations accounting. 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 statements, both of which would be material to our financial statements. See Note 3.

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 and other governmental regulations, 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. Beginning July 1, 2013, TEP began deferring costs associated with the majority of its legal AROs as regulatory assets because new depreciation rates approved in the 2013 TEP Rate Order include these costs. Deferred costs are amortized over the life of the underlying asset.

A liability for the fair value of a legal asset retirement obligation (ARO) is recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a part of the carrying amount of the long-lived assets. The asset retirement cost is subsequently charged to depreciation expense over the useful life of the asset or lease term. Upon retirement of the asset, we will either settle the obligation for its recorded amount or incur a gain or loss if the actual costs differ from the recorded amount.

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 the expiration of the leases. Additionally, TEP and UNS Electric 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 or UNS Electric to remove the PV facilities upon expiration of the leases. TEP's ARO related to the PV assets is estimated to be approximately $9 million at the retirement dates, and UNS Electric's ARO is estimated to be approximately $3 million. 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 and Springerville environmental obligations will be approximately $166 million at the retirement dates. No other legal obligations to retire generation plant assets were identified.

TEP, UNS Electric and UNS Gas have various transmission and distribution lines that operate under leases and rights-of-way that contain end dates and may contain site restoration clauses. TEP, UNS Electric and UNS Gas operate 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.

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The total net present value of TEP's ARO liability was $22 million at December 31, 2013. The net present value of UNS Electric's ARO liability was $1 million at December 31, 2013. ARO liabilities are reported in Deferred Credits and Other Liabilities—Other on the balance sheets. UNS Gas has not identified any AROs associated with removal of its long-lived assets. See Note 5.
Additionally, the authorized depreciation rates for TEP, UNS Electric and UNS Gas include a component designed to accrue the future costs of retiring assets for which no legal obligations exist. The accumulated balances at December 31, 2013 representing non-legal asset retirement obligation accruals, less actual removal costs incurred, net of salvage proceeds realized, are included in Deferred Credits and Other Liabilities, Regulatory Liabilities – Noncurrent on the balance sheets. See Note 3.
Pension and Other Retiree Benefit Plan Assumptions
TEP, UNS Electric, and UNS Gas record 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 10 discusses the rate of return and discount rate used in the calculation of pension plan and other retiree plan obligations for TEP, UNS Electric, and UNS Gas.
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, 2013, TEP discounted its future pension plan obligations at between 5.0% and 5.1% and its other retiree plan obligations at a rate of 4.7%. 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 60^{th} and 90^{th} 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 $10 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. A 25-basis point change in the discount rate would not significantly impact plan expense.
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, 2013. 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 2014 by $1 million.
TEP used a current year health care cost trend rate of 6.7% in valuing its retiree benefit obligation at December 31, 2013. 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 change the retiree benefit obligation by approximately $5 million and the related plan expense in 2014 by $1 million.
In 2014, TEP will incur pension costs of approximately $8 million and other retiree benefit costs of approximately $6 million. TEP expects to charge approximately $10 million of these costs to O&M expense, $3 million to capital, and $1 million to Other Expense. TEP expects to make pension plan contributions of $9 million in 2014. In 2009, TEP established a VEBA trust to fund its other retiree benefit plan. In 2014, TEP expects to make benefit payments to

retirees under the retiree benefit plan of approximately $5 million and contributions to the VEBA trust of $1 million, net of distributions.

UNS Electric and UNS Gas discounted their future pension plan obligations using a rate of 5.2% at December 31, 2013. For UNS Electric and UNS Gas' pension plan, a 25-basis point change in the discount rate would impact the benefit obligation and pension expense by less than $1 million. UNS Electric and UNS Gas will record pension expense of $2 million in 2014, of which less than $1 million will be capitalized. UNS Electric and UNS Gas expect to make combined pension plan contributions of $1 million in 2014.

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UNS Electric and UNS Gas discounted their other retiree plan obligations using a rate of 4.7% at December 31, 2013. UNS Electric and UNS Gas will record retiree medical benefit expense and make benefit payments to retirees under the retiree benefit plan of less than $0.5 million in 2014.

Accounting for Derivative Instruments and Hedging Activities

Commodity Derivative Contracts

TEP, UNS Electric, and UNS Gas enter 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 has excess supply and the market price of energy exceeds its marginal cost. TEP and UNS Gas enter into forward gas commodity price swap agreements to lock in fixed prices on a portion of forecasted gas purchases. UNS Electric enters into forward gas commodity price swap agreements to hedge the price risk associated with forward power purchase agreements 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 sheets of TEP, UNS Electric, and UNS Gas based on our ability to recover the prudent 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 or PGA mechanisms. The market prices used to determine fair values for TEP’s, UNS Electric’s, and UNS Gas' derivative instruments at December 31, 2013, are estimated based on various factors including broker quotes, exchange prices, over the counter prices, and time value.

TEP, UNS Electric, and UNS Gas manage 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, 2013, approximately $25 million of variable rate lease debt for the Springerville Common Facilities Lease had been hedged through an interest rate swap agreement through July 1, 2014, and $34 million had been hedged through January 2, 2020. In August 2009, TEP entered into a swap that had the effect of converting $50 million of variable-rate IDBs to a fixed rate from September 2009 through September 2014.

In August 2011, UNS Electric entered into an interest rate swap with the effect of converting the variable interest rate for their $30 million term loan to a fixed rate from August 2011 through August 2015. See Note 6.

Commodity Cash Flow Hedge

TEP hedges the cash flow risk associated with a six-year power wholesale supply agreement using a six-year power purchase swap agreement. Unrealized gains and losses are recorded in AOCI. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk, Commodity Price Risk and Note 1.

Revenue Recognition

TEP’s, UNS Electric’s, and UNS Gas' retail revenues, which are recognized in the period that electricity or energy is delivered and consumed by customers, include unbilled revenue based on an estimate of kWh/therms 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/therms delivered to the kWh/therms billed to our retail customers. The excess of estimated kWh/therms delivered over kWh/therms 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 and UNS Electric’s actual load, the unbilled revenue amount increases during the spring and summer and decreases during the fall and

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winter. Conversely the unbilled revenue amount for UNS Gas sales increases during the fall and winter and decreases during the spring and summer. A provision for uncollectible accounts is recorded as a component of O&M expense.

Plant Asset Depreciable Lives

TEP, UNS Electric, and UNS Gas have significant investments in electric generation assets and electric and natural gas 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 5. 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 statements. The ACC approves depreciation rates for all generation and distribution assets. Depreciation rates for such assets cannot be changed without ACC approval. TEP and UNS Electric transmission assets are subject to the jurisdiction of the FERC. See Note 1.

The 2013 TEP Rate Order approved a change in authorized depreciation rates for generation and distribution plant from an average of 3.32% to 3.00% , effective July 1, 2013. The change in depreciation rates will have the effect of reducing depreciation expense by approximately $11 million annually. The reduction in depreciation expense is primarily due to revised estimates of removal costs, net of estimated salvage value for interim and final retirements. See Note 3.

In January 2010, TEP obtained an updated depreciation study which indicated that its transmission assets' depreciable lives should be extended. As a result, TEP adopted new FERC approved transmission depreciation rates effective January 2010.

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.

Consolidated income tax liabilities are allocated to subsidiaries based on their taxable income and deductions as reported in the 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, 2013, UNS Energy had a $7 million valuation allowance. The valuation allowances related to unregulated investments' losses are treated as capital losses for income tax purposes. If UNS Energy incurs additional capital losses in the future, a valuation allowance will be recorded against the deferred tax asset unless management can identify future capital gains to offset the losses. See Note 9.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

The FASB issued guidance for the recognition, measurement, and disclosure of certain obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. On adoption, an entity would recognize and disclose in the financial statements its obligation from a joint and several liability arrangement as the sum of the amount the entity agreed with its co-obligors that it will pay, and any additional amount the entity expects to pay on behalf of its co-obligors. This guidance will be effective in the first quarter of 2014. We do not expect the adoption of this guidance to have a material impact on our financial condition, results of operations, or cash flows.

The FASB issued guidance which permits an entity to designate the Federal Funds Rate (the interest rate at which depository institutions lend balances to each other overnight) as a benchmark interest rate for fair value and cash flow hedges. Prior to this guidance, only interest rates on direct treasury obligations of the U.S. Government and the LIBOR were considered benchmark interest rates in the U.S. This guidance is effective immediately, and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. We have not entered into any new cash flow or fair value hedges since the effective date of this guidance. We do not expect this guidance to have a material impact on our financial condition, results of operations, or cash flows.

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The FASB issued new guidance on the financial statement presentation of unrecognized tax benefits when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. We will be required to comply with the guidance on a prospective basis beginning in the first quarter of 2014. Although adoption of this new guidance may impact how such items are classified on our balance sheets, we do not expect such changes to be material. In addition, we do not expect any material changes in the presentations of our other financial statements.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. UNS Energy and TEP are 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 UNS Energy or 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”, “estimates”, “expects”, “intends”, “plans”, “predicts”, “projects”, and similar expressions. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All such forward-looking statements, whether written or oral, and whether made by or on behalf of UNS Energy or TEP, are expressly qualified by these cautionary statements and any other cautionary statements which may accompany the forward-looking statements. In addition, UNS Energy and TEP disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

Forward-looking statements involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. 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 Item 1A. Risk Factors, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and other parts of this report: state and federal regulatory and legislative decisions and actions; regional economic and market conditions which could affect customer growth and energy usage; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets; the performance of the stock market and changing interest rate environment, which affect the value of our pension and other retiree benefit plan assets and the related contribution requirements and expense; unexpected increases in O&M expense; resolution of pending litigation matters; changes in accounting standards; changes in critical accounting estimates; the ongoing restructuring of the electric industry; changes to long-term contracts; the cost of fuel and power supplies; cyber attacks or challenges to our information security; and the performance of TEP’s generating plants.

ITEM 7A. – QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

We are exposed to various forms of market risk. Changes in interest rates, returns on marketable securities, and changes in commodity prices may affect our future financial results.

See Safe Harbor for Forward-Looking Statements.

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 activities of TEP and the fuel and power procurement activities at TEP, UNS Electric, and UNS Gas. Our Risk Management Committee, which meets on a quarterly basis and as needed, consists of officers from the finance, accounting, legal, wholesale marketing, transmission and distribution operations, and generation operations departments of UNS Energy. To limit TEP, UNS Electric, and UNS Gas’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, UNS Electric, and UNS Gas'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 $215 million at December 31, 2013 in tax-exempt variable rate debt outstanding. The interest rates on TEP's tax-exempt variable rate debt are reset weekly or monthly. The average rate on TEP's weekly variable rate debt (excluding letter of credit fees) was 0.12% in 2013 and 0.17% in 2012. The average weekly interest rate ranged from 0.06% to 0.48% in 2013 and 0.06% to 0.26% during 2012. Although short-term interest rates have been relatively low and stable in 2013 and 2012, 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 $2 million.

TEP manages 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 fixed-for-floating interest rate swaps in place to hedge floating rate interest rate risk associated with $55 million of Springerville Common Facilities lease debt and $50 million of its variable rate IDBs.

In 2011, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a $30 million notional amount through August 2015 to hedge the interest rate risk associated with its $30 million credit agreement.

Interest Rate Swaps

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

	2013	2012	2011
	Millions of Dollars		
Unrealized Gains (Losses)	$(1)	$(2)	$(5)

Revolving Credit Facilities

UNS Energy, TEP, UNS Electric, and UNS Gas are also subject to interest rate risk resulting from changes in interest rates on their borrowings under revolving credit facilities. Revolving credit borrowings may be made on the basis of a spread over LIBOR or an Alternate Base Rate. As a result, UNS Energy, TEP, UNS Electric, and UNS Gas may experience significant volatility in the rates paid on LIBOR borrowings under their revolving credit facilities.

Marketable Securities Risk

UNS Energy has a short-term investment policy which governs the investment of excess cash balances by UNS Energy and its subsidiaries. We review this policy periodically in response to market conditions to adjust, if necessary, the maturities and concentrations by investment type and issuer in the investment portfolio. At December 31, 2013, UNS Energy's short-term investments consisted of liquid, highly-rated money market funds and certificates of deposit. These short-term investments are classified as Cash and Cash Equivalents on the balance sheet.

TEP had marketable securities comprised of investments in lease equity with an estimated fair value of $25 million at December 31, 2013, and $32 million of lease debt and equity at December 31, 2012. At December 31, 2013, the carrying value exceeded fair value by $11 million. No impairment was recorded as TEP expects to recover the full carrying value of its lease equity investment in future rates charged to retail customers. At December 31, 2012, the carrying value exceeded the fair value by $13 million. These securities represent TEP's investments in lease debt and equity underlying certain of TEP's capital lease obligations. Changes in the fair value of such debt securities do not present a material risk to TEP, as TEP intends to hold these investments to maturity.

Commodity Price Risk

TEP

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

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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

Through the end of the contract in May 2016, SRP is required to purchase 500,000 MWh of on-peak energy per year from TEP. TEP does not receive a demand charge and the price of energy is based on a discount to the price of on-peak power on the Palo Verde Market Index. As of February 14, 2014, the average forward price of on-peak power on the Palo Verde Market Index for the calendar year 2014 was $46 per MWh.

Each $5 change in the per MWh market price of on-peak power can affect annual pre-tax income by approximately $3 million.

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 3 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, 2013, 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 in regulatory assets or regulatory liabilities, TEP recorded the following net unrealized gains (losses):

	2013	2012	2011
	Millions of Dollars		
Unrealized Gains (Losses)	$—	$6	$(2)

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The chart below displays the valuation methodologies and maturities of TEP's power and gas derivative contracts.

	Unrealized Gain (Loss) of TEP's Hedging Activities Millions of Dollars			
Source of Fair Value at Dec. 31, 2013	Maturity 0 – 6 months	Maturity 6 – 12 months	Maturity over 1 yr.	Total Unrealized Gain (Loss)
Prices Actively Quoted	$(1)	$1	$1	$1
Prices Based on Models and Other Valuation Methods	(1)	(1)	—	(2)
Total	$(2)	$—	$1	$(1)

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 net losses reported as a regulatory asset by approximately $1 million; for gas swaps and collars contracts, a 10% change in the market price of energy would affect unrealized net gains reported as a regulatory 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 a PPFAC mechanism which allows for the recovery of costs from retail customers. TEP's coal supply contract for Springerville Units 1 and 2 expires in 2020. TEP expects coal reserves to be sufficient to supply the estimated requirements for Units 1 and 2 for their presently estimated remaining lives. The coal price is determined by the cost of Powder River Basin coal delivered to Springerville Unit 3 subject to a floor and ceiling. TEP does not have a long-term coal supply contract for Sundt Unit 4. TEP purchases coal for Sundt Unit 4 on the spot market and can supply that unit with natural gas when the price is competitive with coal. Coal burned at Sundt Unit 4 represents less than 10% of TEP's total coal consumption.

TEP also participates in jointly-owned generating facilities at Four Corners, Navajo, and San Juan, where coal supplies are under long-term contracts administered by the operating agents. TEP expects coal reserves available to these three jointly-owned generating facilities to be sufficient for the remaining lives of the stations.

The contracts to purchase coal for use at the jointly-owned facilities require TEP to purchase minimum amounts of coal at an estimated average annual cost of $21 million for the next five years. See Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations, UNS Energy Consolidated, Liquidity and Capital Resources, Contractual Obligations and Note 7.

UNS Electric

UNS Electric is exposed to commodity price risk from changes in the price for electricity and natural gas. This risk is mitigated through hedging practices, and UNS Electric has a PPFAC mechanism which allows for the recovery of purchased power and fuel costs from retail customers.

The PPFAC allows UNS Electric to recover its fuel, transmission, and purchased power costs, including demand charges, broker fees, and the prudent costs of contracts for hedging fuel and purchased power costs for its retail customers.

As a result of the 2013 UNS Electric Rate Order, UNS Electric's PPFAC rate reflects a weighted, 12-month rolling average of actual fuel and purchased power costs incurred by UNS Electric. The PPFAC rate adjusts monthly, but the change in the PPFAC rate is banded, so the new monthly PPFAC rate cannot increase or decrease the total average retail purchased power and fuel rate by more than 0.83 percent from the preceding month's rate. UNS Electric is required to file for a PPFAC rate adjustment if the PPFAC bank balance is over-collected by more than $10 million on a billed-to-customer basis. At December 31, 2013, the PPFAC bank balance was over-collected by $14 million on a billed-to-customer basis. The new PPFAC rate effective on January 1, 2014 is designed to address any over- or under-collected balances. See Note 3.

UNS Electric enters into various power supply agreements for periods of one to five years. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. Because of the new 12-month rolling average structure of the current PPFAC, costs are expected to be recovered on a more timely basis.

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For UNS Electric's forward power contracts, a 10% change in market prices would affect unrealized net losses reported as a regulatory asset by approximately $3 million.

UNS Electric hedges a portion of its natural gas exposure from gas-indexed purchased power agreements with fixed price contracts. In addition, UNS Electric hedges a portion of its anticipated natural gas exposure from plant fuel. UNS Electric will satisfy its remaining gas and purchased power needs through a combination of purchases in the short-term and spot markets.

As required by fair value accounting rules, for the year ended December 31, 2013, UNS Electric 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 in regulatory assets or regulatory liabilities, UNS Electric recorded the following net unrealized gains (losses):

	2013	2012	2011
	Millions of Dollars		
Unrealized Gains (Losses)	$5	$9	$(1)

For UNS Electric's forward gas contracts, a 10% increase in market prices would result in an increase in unrealized net gains reported as a regulatory liability by approximately $5 million. A 10% decrease in market prices would result in a decrease in unrealized net gains reported as a regulatory liability by approximately $4 million.

UNS Gas

UNS Gas is subject to commodity price risk, primarily from the changes in the price of natural gas purchased for its customers. This risk is mitigated through the PGA mechanism which provides an adjustment to UNS Gas' Retail Rates to recover the prudently incurred actual costs of gas and transportation. UNS Gas further reduces this risk by purchasing forward fixed price contracts or entering into financial gas swaps for a portion of its projected gas needs under its Price Stabilization Plan.

As required by fair value accounting rules, for the year ended December 31, 2013, UNS Gas 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 in regulatory assets or regulatory liabilities, UNS Gas recorded the following net unrealized gains:

	2013	2012	2011
	Millions of Dollars		
Unrealized Gains	$4	$6	$1

For UNS Gas' forward gas contracts, a 10% change in market prices would affect unrealized net gains reported as a regulatory liability by approximately $2 million.

Credit Risk

UNS Energy 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. A positive value means that we are exposed to the creditworthiness of our counterparties. 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 a letter of credit. Conversely, a negative value means that a counterparty is exposed to the creditworthiness of TEP, UNS Gas, or UNS Electric. If such exposure exceeds credit limits or collateral thresholds, we may be required to post collateral in the form of cash or LOCs.

TEP, UNS Electric, and UNS Gas each have entered into short-term and long-term transactions with several financial institution counterparties with terms of one month through five years. As of December 31, 2013, the combined credit exposure to TEP, UNS Electric, and UNS Gas from financial institution counterparties was approximately $3 million.

As of December 31, 2013, TEP's total credit exposure related to its wholesale marketing and gas hedging activities was approximately $15 million. TEP had one non-investment grade counterparty with exposure of greater than 10% of its total credit exposure, totaling approximately $3 million. TEP's total exposure to non-investment grade counterparties was $3 million.

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At December 31, 2013, 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.

UNS Gas is subject to credit risk from non-performance by its supply and hedging counterparties to the extent that these contracts have a mark-to-market value in favor of UNS Gas. As of December 31, 2013, UNS Gas had purchased under fixed price contracts approximately 30% of its expected consumption for the 2014/2015 winter season. At December 31, 2013, UNS Gas had no mark-to-market credit exposure under its supply and hedging contracts. As of December 31, 2013 UNS Gas had posted no cash collateral and no LOCs as credit enhancements with its counterparties, and did not hold any collateral from counterparties.

UNS Electric enters into energy purchase agreements as well as gas hedging contracts to hedge the risk in its gas-indexed power purchase agreements. To the extent that such contracts have a positive mark-to-market value, UNS Electric is exposed to credit risk under those contracts. At December 31, 2013, UNS Electric had less than $1 million in credit exposure under such contracts. As of December 31, 2013, UNS Electric had posted less than $1 million in LOCs and no cash collateral as credit enhancements with its counterparties, and had not collected any collateral margin from its counterparties.

ITEM 8. – CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

UNS Energy—Management’s Report on Internal Controls Over Financial Reporting

UNS Energy’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 UNS Energy’s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the 1992 Committee of Sponsoring Organizations of the Treadway Commission (COSO) Internal Control – Integrated Framework.

Based on management’s assessment using those criteria management has concluded that, as of December 31, 2013, UNS Energy’s internal control over financial reporting was effective.

The effectiveness of UNS Energy’s internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report in Item 8 of this Annual Report on Form 10-K.

Tucson Electric Power Company—Management’s Report on Internal Controls 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, 2013. In making this assessment, management used the criteria set forth by the 1992 COSO Internal Control – Integrated Framework.

Based on management’s assessment using those criteria, management has concluded that, as of December 31, 2013, TEP’s internal control over financial reporting was effective.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
UNS Energy Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of UNS Energy Corporation and its subsidiaries at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
February 25, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholder of
Tucson Electric Power Company:
In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Tucson Electric Power Company and its subsidiaries at December 31, 2013 and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits 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 audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
February 25, 2014

UNS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2013	2012	2011
	Thousands of Dollars (Except Per Share Amounts)		
Operating Revenues			
Electric Retail Sales	$1,102,769	$1,087,279	$1,085,822
Electric Wholesale Sales	135,160	125,414	132,346
Gas Retail Sales	125,478	123,133	145,053
Other Revenues	121,153	125,940	115,481
Total Operating Revenues	1,484,560	1,461,766	1,478,702
Operating Expenses			
Fuel	332,279	327,832	324,520
Purchased Energy	252,532	224,696	276,610
Transmission and Other PPFAC Recoverable Costs	23,012	14,540	7,334
Increase (Decrease) to Reflect PPFAC/PGA Recovery Treatment	(16,313)	32,246	(4,932)
Total Fuel and Purchased Energy	591,510	599,314	603,532
Operations and Maintenance	389,699	383,689	379,220
Depreciation	149,615	141,303	133,832
Amortization	27,557	35,784	30,983
Taxes Other Than Income Taxes	54,683	49,881	49,428
Total Operating Expenses	1,213,064	1,209,971	1,196,995
Operating Income	271,496	251,795	281,707
Other Income (Deductions)			
Interest Income	534	1,106	4,568
Other Income	7,880	4,928	7,958
Other Expense	(3,463)	(7,723)	(5,278)
Appreciation in Fair Value of Investments	2,833	1,892	329
Total Other Income (Deductions)	7,784	203	7,577
Interest Expense			
Long-Term Debt	71,180	71,909	73,217
Capital Leases	25,140	33,613	40,359
Other Interest Expense	538	1,983	2,535
Interest Capitalized	(3,483)	(2,153)	(3,753)
Total Interest Expense	93,375	105,352	112,358
Income Before Income Taxes	185,905	146,646	176,926
Income Tax Expense	58,427	55,727	66,951
Net Income	$127,478	$90,919	$109,975
Weighted-Average Shares of Common Stock Outstanding (000)			
Basic	41,618	40,362	36,962
Diluted	41,975	41,755	41,609
Earnings Per Share			
Basic	$3.06	$2.25	$2.98
Diluted	$3.04	$2.20	$2.75
Dividends Declared Per Share	$1.74	$1.72	$1.68

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2013	2012	2011
	Thousands of Dollars		
Comprehensive Income			
Net Income	$127,478	$90,919	$109,975
Other Comprehensive Income (Loss)			
Net Changes in Fair Value of Cash Flow Hedges, net of income tax (expense) benefit of $(1,850), $(743), and $964	2,825	1,134	(1,473)
SERP Benefit Amortization, net of income tax (expense) benefit of $(572), $608, and $(804)	916	(840)	1,158
Total Other Comprehensive Income (Loss), Net of Tax	3,741	294	(315)
Total Comprehensive Income	$131,219	$91,213	$109,660

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2013	2012	2011
	Thousands of Dollars		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	$1,208,967	$1,197,390	$1,163,537
Cash Receipts from Electric Wholesale Sales	160,947	149,722	183,151
Cash Receipts from Gas Retail Sales	138,775	141,590	159,529
Cash Receipts from Operating Springerville Units 3 & 4	114,258	107,927	104,754
Cash Receipts from Gas Wholesale Sales	3,740	5,233	12,404
Interest Received	517	2,947	6,334
Income Tax Refunds Received	11	1,821	4,672
Performance Deposits Received	—	200	7,050
Other Cash Receipts	35,142	24,105	23,937
Fuel Costs Paid	(285,812)	(321,355)	(277,386)
Purchased Energy Costs Paid	(280,920)	(250,231)	(328,713)
Payment of Operations and Maintenance Costs	(260,453)	(291,512)	(295,662)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	(182,488)	(187,257)	(179,766)
Wages Paid, Net of Amounts Capitalized	(131,710)	(127,176)	(122,370)
Interest Paid, Net of Amounts Capitalized	(66,610)	(69,478)	(68,027)
Capital Lease Interest Paid	(22,553)	(28,788)	(32,103)
Income Taxes Paid	(316)	—	(700)
Performance Deposits Paid	—	(200)	(4,550)
Wholesale Gas Costs Paid	—	—	(11,822)
Other Cash Payments	(10,983)	(6,829)	(6,949)
Net Cash Flows—Operating Activities	420,512	348,109	337,320
Cash Flows from Investing Activities			
Capital Expenditures	(325,886)	(307,277)	(374,122)
Purchase of Intangibles—Renewable Energy Credits	(26,948)	(10,317)	(5,992)
Return of Investments in Springerville Lease Debt	9,104	19,278	38,353
Change in Restricted Cash	4,134	(1,445)	—
Proceeds from Note Receivable	—	15,000	—
Other, net	5,786	21,862	14,673
Net Cash Flows—Investing Activities	(333,810)	(262,899)	(327,088)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facilities	139,000	359,000	391,000
Repayments of Borrowings Under Revolving Credit Facilities	(108,000)	(381,000)	(351,000)
Payments of Capital Lease Obligations	(99,621)	(89,452)	(74,381)
Common Stock Dividends Paid	(72,234)	(69,648)	(61,904)
Proceeds from Stock Options Exercised	3,831	3,570	8,115
Proceeds from Common Stock Issuance	464	—	—
Proceeds from Issuance of Long-Term Debt	—	149,513	340,285
Repayments of Long-Term Debt	—	(9,341)	(252,125)
Other, net	818	(324)	(1,431)
Net Cash Flows—Financing Activities	(135,742)	(37,682)	(1,441)
Net Increase (Decrease) in Cash and Cash Equivalents	(49,040)	47,528	8,791
Cash and Cash Equivalents, Beginning of Year	123,918	76,390	67,599
Cash and Cash Equivalents, End of Year	$74,878	$123,918	$76,390

See Note 14 for supplemental cash flow information.

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2013	2012
	Thousands of Dollars	
ASSETS		
Utility Plant		
Plant in Service	$5,192,122	$5,005,768
Utility Plant Under Capital Leases	637,957	582,669
Construction Work in Progress	201,959	128,621
Total Utility Plant	6,032,038	5,717,058
Less Accumulated Depreciation and Amortization	(1,982,524)	(1,921,733)
Less Accumulated Amortization of Capital Lease Assets	(514,677)	(494,962)
Total Utility Plant—Net	3,534,837	3,300,363
Investments and Other Property		
Investments in Lease Equity	36,194	36,339
Other	34,971	36,537
Total Investments and Other Property	71,165	72,876
Current Assets		
Cash and Cash Equivalents	74,878	123,918
Accounts Receivable—Customer	104,596	93,742
Unbilled Accounts Receivable	52,403	53,568
Allowance for Doubtful Accounts	(6,833)	(6,545)
Materials and Supplies	88,085	93,322
Deferred Income Taxes—Current	59,681	34,260
Regulatory Assets—Current	52,763	51,619
Fuel Inventory	44,317	62,019
Derivative Instruments	5,629	3,165
Investments in Lease Debt	—	9,118
Other	15,354	33,567
Total Current Assets	490,873	551,753
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	150,584	191,077
Derivative Instruments	1,180	3,801
Other Assets	24,430	20,559
Total Regulatory and Other Assets	176,194	215,437
Total Assets	$4,273,069	$4,140,429

See Notes to Consolidated Financial Statements.

(Continued)

UNS ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2013	2012
	Thousands of Dollars	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	$1,130,784	$1,065,465
Capital Lease Obligations	149,767	262,138
Long-Term Debt	1,507,070	1,498,442
Total Capitalization	2,787,621	2,826,045
Current Liabilities		
Current Obligations Under Capital Leases	167,659	90,583
Borrowings Under Revolving Credit Facilities	22,000	—
Accounts Payable—Trade	117,503	107,740
Regulatory Liabilities—Current	53,935	43,516
Accrued Taxes Other than Income Taxes	43,880	41,939
Customer Deposits	30,671	34,048
Accrued Employee Expenses	28,148	24,094
Accrued Interest	27,786	31,950
Derivative Instruments	7,534	14,742
Other	17,775	10,517
Total Current Liabilities	516,891	399,129
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	481,662	364,756
Regulatory Liabilities—Noncurrent	302,482	279,111
Pension and Other Retiree Benefits	90,923	159,401
Derivative Instruments	7,100	12,709
Other	86,390	99,278
Total Deferred Credits and Other Liabilities	968,557	915,255
Commitments, Contingencies, and Environmental Matters (Note 7)		
Total Capitalization and Other Liabilities	$4,273,069	$4,140,429

See Notes to Consolidated Financial Statements.
(Concluded)

UNS ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2013	2012
			Thousands of Dollars	
COMMON STOCK EQUITY				
Common Stock-No Par Value			$889,301	$882,138
	2013	2012		
Shares Authorized	75,000,000	75,000,000		
Shares Outstanding	41,538,343	41,343,851		
Retained Earnings			247,532	193,117
Accumulated Other Comprehensive Loss			(6,049)	(9,790)
Total Common Stock Equity			1,130,784	1,065,465
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			—	—
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			192,871	196,843
Springerville Coal Handling Facilities			27,878	48,038
Springerville Common Facilities			96,677	107,840
Total Capital Lease Obligations			317,426	352,721
Less Current Maturities			(167,659)	(90,583)
Total Long-Term Capital Lease Obligations			149,767	262,138
LONG-TERM DEBT				
	Maturity	Interest Rate		
UNS Energy:				
Credit Agreement	2016	Variable	54,000	45,000
Tucson Electric Power Company:				
Variable Rate Bonds	2016 - 2032	Variable	214,802	215,300
Fixed Rate Bonds	2020 - 2040	3.85% – 5.75%	1,008,268	1,008,142
UNS Electric and UNS Gas:				
Senior Notes	2015 – 2026	5.39% – 7.10%	200,000	200,000
UNS Electric:				
Term Loan	2015	Variable	30,000	30,000
Total Long-Term Debt			1,507,070	1,498,442
Total Capitalization			$2,787,621	$2,826,045

See Notes to Consolidated Financial Statements.

UNS ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Shares Outstanding	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Thousands of Shares	Thousands of Dollars			
Balances at December 31, 2010	36,542	$715,687	$124,838	$ (9,769)	$830,756
Net Income			109,975		109,975
Other Comprehensive Loss, net of tax				(315)	(315)
Dividends Declared			(62,158)		(62,158)
Shares Issued for Stock Options	319	8,176			8,176
Shares Issued under Performance Share Awards	57	—			—
Share-based Compensation		2,040			2,040
Balances at December 31, 2011	36,918	725,903	172,655	(10,084)	888,474
Net Income			90,919		90,919
Other Comprehensive Income, net of tax				294	294
Dividends Declared			(70,457)		(70,457)
Shares Issued on Conversion of Notes and Related Tax Effect	4,262	149,805			149,805
Shares Issued for Stock Options	133	3,511			3,511
Shares Issued under Performance Share Awards	31	—			—
Share-based Compensation		2,919			2,919
Balances at December 31, 2012	41,344	882,138	193,117	(9,790)	1,065,465
Net Income			127,478		127,478
Other Comprehensive Income, net of tax				3,741	3,741
Dividends Declared			(73,063)		(73,063)
Shares Issued under Dividend Reinvestment Plan	10	464			464
Shares Issued for Stock Options	127	3,831			3,831
Shares Issued under Performance Share Awards	57	—			—
Share-based Compensation		2,868			2,868
Balances at December 31, 2013	41,538	$889,301	$247,532	$ (6,049)	$1,130,784

We describe limitations on our ability to pay dividends in Note 13.

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2013	2012	2011
	Thousands of Dollars		
Operating Revenues			
Electric Retail Sales	$934,357	$915,879	$903,930
Electric Wholesale Sales	132,500	111,194	129,861
Other Revenues	129,833	134,587	122,595
Total Operating Revenues	1,196,690	1,161,660	1,156,386
Operating Expenses			
Fuel	325,903	318,901	318,268
Purchased Power	112,452	80,137	105,766
Transmission and Other PPFAC Recoverable Costs	12,233	5,722	(1,435)
Increase (Decrease) to Reflect PPFAC Recovery Treatment	(12,458)	31,113	(6,165)
Total Fuel and Purchased Energy	438,130	435,873	416,434
Operations and Maintenance	335,321	334,553	330,801
Depreciation	118,076	110,931	104,894
Amortization	31,294	39,493	34,650
Taxes Other Than Income Taxes	43,498	40,323	40,199
Total Operating Expenses	966,319	961,173	926,978
Operating Income	230,371	200,487	229,408
Other Income (Deductions)			
Interest Income	120	136	3,567
Other Income	5,770	3,953	5,364
Other Expense	(10,715)	(13,574)	(12,064)
Appreciation in Fair Value of Investments	2,833	1,892	329
Total Other Income (Deductions)	(1,992)	(7,593)	(2,804)
Interest Expense			
Long-Term Debt	56,378	55,038	49,858
Capital Leases	25,140	33,613	40,358
Other Interest Expense	87	1,446	1,127
Interest Capitalized	(2,554)	(1,782)	(2,073)
Total Interest Expense	79,051	88,315	89,270
Income Before Income Taxes	149,328	104,579	137,334
Income Tax Expense	47,986	39,109	52,000
Net Income	$101,342	$65,470	$85,334

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2013	2012	2011
	Thousands of Dollars		
Comprehensive Income			
Net Income	$101,342	$65,470	$85,334
Other Comprehensive Income (Loss)			
Net Changes in Fair Value of Cash Flow Hedges, net of income tax (expense) benefit of $(1,793), $(887), and $941	2,738	1,354	(1,433)
SERP Benefit Amortization, net of income tax (expense) benefit of $(572), $608, and $(804)	916	(840)	1,158
Total Other Comprehensive Income (Loss), Net of Tax	3,654	514	(275)
Total Comprehensive Income	$104,996	$65,984	$85,059

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2013	2012	2011
	Thousands of Dollars		
Cash Flows from Operating Activities			
Cash Receipts from Electric Retail Sales	$1,020,903	$1,006,926	$963,247
Cash Receipts from Electric Wholesale Sales	146,880	124,594	152,618
Cash Receipts from Operating Springerville Units 3 & 4	114,258	107,927	104,754
Reimbursement of Affiliate Charges	23,468	20,926	18,448
Cash Receipts from Gas Wholesale Sales	3,271	4,652	11,825
Interest Received	509	2,025	5,367
Income Tax Refunds Received	77	493	7,492
Other Cash Receipts	25,079	18,850	19,611
Fuel Costs Paid	(280,639)	(313,742)	(271,975)
Payment of Operations and Maintenance Costs	(253,054)	(282,752)	(287,615)
Taxes Other Than Income Taxes Paid, Net of Amounts Capitalized	(144,849)	(147,859)	(139,728)
Purchased Power Costs Paid	(115,008)	(81,328)	(117,224)
Wages Paid, Net of Amounts Capitalized	(110,995)	(104,955)	(100,942)
Interest Paid, Net of Amounts Capitalized	(52,589)	(52,125)	(45,433)
Capital Lease Interest Paid	(22,553)	(28,786)	(32,103)
Income Taxes Paid	—	(1,796)	(2,346)
Wholesale Gas Cost Paid	—	—	(11,822)
Other Cash Payments	(8,567)	(5,131)	(5,880)
Net Cash Flows—Operating Activities	346,191	267,919	268,294
Cash Flows from Investing Activities			
Capital Expenditures	(252,848)	(252,782)	(351,890)
Purchase of Intangibles—Renewable Energy Credits	(23,280)	(8,889)	(5,111)
Return of Investments in Springerville Lease Debt	9,104	19,278	38,353
Change in Restricted Cash	4,134	(1,445)	—
Other, net	3,228	15,957	6,637
Net Cash Flows—Investing Activities	(259,662)	(227,881)	(312,011)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facility	78,000	189,000	220,000
Repayments of Borrowings Under Revolving Credit Facility	(78,000)	(199,000)	(210,000)
Payments of Capital Lease Obligations	(99,621)	(89,452)	(74,343)
Dividends Paid to UNS Energy	(40,000)	(30,000)	—
Proceeds from Issuance of Long-Term Debt	—	149,513	260,285
Repayments of Long-Term Debt	—	(6,535)	(172,460)
Equity Investment from UNS Energy	—	—	30,000
Other, net	(1,316)	(1,539)	(2,030)
Net Cash Flows—Financing Activities	(140,937)	11,987	51,452
Net Increase (Decrease) in Cash and Cash Equivalents	(54,408)	52,025	7,735
Cash and Cash Equivalents, Beginning of Year	79,743	27,718	19,983
Cash and Cash Equivalents, End of Year	$25,335	$79,743	$27,718

See Note 14 for supplemental cash flow information.
See Notes to Consolidated Financial Statements.

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TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2013	2012
	Thousands of Dollars	
ASSETS		
Utility Plant		
Plant in Service	$4,467,667	$4,348,041
Utility Plant Under Capital Leases	637,957	582,669
Construction Work in Progress	180,485	98,460
Total Utility Plant	5,286,109	5,029,170
Less Accumulated Depreciation and Amortization	(1,826,977)	(1,783,787)
Less Accumulated Amortization of Capital Lease Assets	(514,677)	(494,962)
Total Utility Plant—Net	2,944,455	2,750,421
Investments and Other Property		
Investments in Lease Equity	36,194	36,339
Other	33,488	35,091
Total Investments and Other Property	69,682	71,430
Current Assets		
Cash and Cash Equivalents	25,335	79,743
Accounts Receivable—Customer	80,211	71,813
Unbilled Accounts Receivable	34,369	33,782
Allowance for Doubtful Accounts	(4,825)	(4,598)
Accounts Receivable—Due from Affiliates	6,064	5,720
Materials and Supplies	75,200	80,377
Deferred Income Taxes—Current	63,497	37,212
Fuel Inventory	44,027	61,737
Regulatory Assets—Current	42,555	34,345
Derivative Instruments	2,137	2,230
Investments in Lease Debt	—	9,118
Other	12,923	32,163
Total Current Assets	381,493	443,642
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	141,030	178,330
Derivative Instruments	167	1,354
Other Assets	19,233	15,869
Total Regulatory and Other Assets	160,430	195,553
Total Assets	$3,556,060	$3,461,046

See Notes to Consolidated Financial Statements.
(Continued)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2013	2012
	Thousands of Dollars	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	$925,923	$860,927
Capital Lease Obligations	149,767	262,138
Long-Term Debt	1,223,070	1,223,442
Total Capitalization	2,298,760	2,346,507
Current Liabilities		
Current Obligations Under Capital Leases	167,659	90,583
Accounts Payable—Trade	88,556	82,122
Accounts Payable—Due to Affiliates	9,153	3,134
Accrued Taxes Other than Income Taxes	34,485	33,060
Accrued Employee Expenses	24,454	20,715
Regulatory Liabilities—Current	23,701	20,822
Accrued Interest	22,785	26,965
Customer Deposits	21,354	24,846
Derivative Instruments	5,531	4,899
Other	9,244	7,085
Total Current Liabilities	406,922	314,231
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	420,878	319,216
Regulatory Liabilities—Noncurrent	263,270	241,189
Pension and Other Retiree Benefits	84,936	149,718
Derivative Instruments	5,161	10,565
Other	76,133	79,620
Total Deferred Credits and Other Liabilities	850,378	800,308
Commitments, Contingencies, and Environmental Matters (Note 7)		
Total Capitalization and Other Liabilities	$3,556,060	$3,461,046

See Notes to Consolidated Financial Statements.

(Concluded)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31,	
			2013	2012
			Thousands of Dollars	
COMMON STOCK EQUITY				
Common Stock-No Par Value			$888,971	$888,971
	2013	2012		
Shares Authorized	75,000,000	75,000,000		
Shares Outstanding	32,139,434	32,139,434		
Capital Stock Expense			(6,357)	(6,357)
Accumulated Earnings (Deficit)			49,185	(12,157)
Accumulated Other Comprehensive Loss			(5,876)	(9,530)
Total Common Stock Equity			925,923	860,927
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			—	—
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			192,871	196,843
Springerville Coal Handling Facilities			27,878	48,038
Springerville Common Facilities			96,677	107,840
Total Capital Lease Obligations			317,426	352,721
Less Current Maturities			(167,659)	(90,583)
Total Long-Term Capital Lease Obligations			149,767	262,138
LONG-TERM DEBT				
	Maturity	Interest Rate		
Variable Rate Bonds	2016 - 2032	Variable	214,802	215,300
Fixed Rate Bonds	2020 - 2040	3.85% – 5.75%	1,008,268	1,008,142
Total Long-Term Debt			1,223,070	1,223,442
Total Capitalization			$2,298,760	$2,346,507

See Notes to Consolidated Financial Statements.

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

	Common Stock	Capital Stock Expense	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
	Thousands of Dollars				
Balances at December 31, 2010	$858,971	$(6,357)	$(132,961)	$ (9,769)	$709,884
Net Income			85,334		85,334
Other Comprehensive Loss, net of tax				(275)	(275)
Capital Contribution from UNS Energy	30,000				30,000
Balances at December 31, 2011	888,971	(6,357)	(47,627)	(10,044)	824,943
Net Income			65,470		65,470
Other Comprehensive Income, net of tax				514	514
Dividends Declared			(30,000)		(30,000)
Balances at December 31, 2012	888,971	(6,357)	(12,157)	(9,530)	860,927
Net Income			101,342		101,342
Other Comprehensive Income, net of tax				3,654	3,654
Dividends Declared			(40,000)		(40,000)
Balances at December 31, 2013	$888,971	$(6,357)	$49,185	$ (5,876)	$925,923

We describe limitations on our ability to pay dividends in Note 13.
See Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS

UNS Energy Corporation (UNS Energy) is a utility services holding company engaged, through its subsidiaries, in the electric generation and energy delivery business. Each of UNS Energy’s subsidiaries is a separate legal entity with its own assets and liabilities. UNS Energy owns 100% of Tucson Electric Power Company (TEP), UniSource Energy Services, Inc. (UES), Millennium Energy Holdings, Inc. (Millennium), and UniSource Energy Development Company (UED).

TEP is a regulated utility and UNS Energy’s largest operating subsidiary, representing approximately 83% of UNS Energy’s total assets as of December 31, 2013. TEP generates, transmits and distributes electricity to approximately 413,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. In addition, TEP operates Springerville Generating Station (Springerville) Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agriculture Improvement and Power District (SRP).

UES wholly-owns two regulated utilities: UNS Electric, Inc. (UNS Electric) and UNS Gas, Inc. (UNS Gas). UNS Electric is a regulated utility, which generates, transmits and distributes electricity to approximately 93,000 retail customers in Mohave and Santa Cruz counties in Arizona. UNS Gas is a regulated gas distribution company, which services approximately 150,000 retail customers in Mohave, Yavapai, Coconino, Navajo, and Santa Cruz counties in Arizona.

UED and Millennium’s investments in unregulated businesses represent less than 1% of UNS Energy’s assets as of December 31, 2013.

Our business is comprised of three reporting segments – TEP, UNS Electric, and UNS Gas.

References to “we” and “our” are to UNS Energy and its subsidiaries, collectively.

See Note 2 for information regarding a pending merger with Fortis, Inc.

BASIS OF PRESENTATION

UNS Energy'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 3. The consolidated financial statements include the accounts of UNS Energy and all of its subsidiaries. In the consolidation process, accounts of the parent and subsidiaries are combined, and intercompany balances and transactions are eliminated. Intercompany profits on transactions between regulated entities are not eliminated if recovery from ratepayers is probable. See Note 4. 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 in the consolidated statements of income. See Note 5.

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.

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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 FERC-approved transmission tariffs. Regulatory liabilities generally represent expected future costs that have already been collected from customers or items that are expected to be returned to customers through future billing 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 3.

TEP, UNS Electric, and UNS Gas apply 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.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2013, we adopted authoritative guidance that:

- Requires disclosure related to offsetting derivative assets and derivative liabilities in accordance with GAAP. See Note 15.
- Requires additional disclosures for amounts reclassified out of Accumulated Other Comprehensive Income (AOCI) by component. See Note 16.

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—Other on the balance sheets. Restricted cash was $2 million at December 31, 2013 and $7 million at December 31, 2012.

UTILITY PLANT

Utility Plant includes the business property and equipment that supports electric and gas services, 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 statements 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. For operations that do not apply regulatory accounting, we capitalize interest related only to debt as a cost of construction. The capitalized interest that relates to debt is recorded as a reduction in Interest Expense in the income statements. The capitalized cost for equity funds is recorded as Other Income in the income statements.

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

	2013	2012	2011
TEP	7.38 %	7.22 %	6.72 %
UNS Electric	8.07 %	7.89 %	8.18 %
UNS Gas	7.89 %	7.95 %	8.32 %

UNS Energy did not capitalize interest related to non-regulated construction activity in 2013 or 2012. UNS Energy capitalized interest on non-regulated construction activity at a rate of 3.30% for 2011.

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 and Note 5. The Arizona Corporation Commission (ACC) approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Depreciation rates are based on average useful lives and include estimates for salvage value and removal costs. Below are the summarized average annual depreciation rates for all utility plant:

	2013	2012	2011
TEP	3.16 %	3.22 %	3.14 %
UNS Electric	3.94 %	3.99 %	4.02 %
UNS Gas	2.63 %	2.69 %	2.84 %

TEP Utility Plant Under Capital Leases

TEP financed the following generation assets with capital leases: Springerville Unit 1; facilities at Springerville used in common with Springerville Unit 1 and Unit 2 (Springerville Common Facilities); and the Springerville Coal Handling Facilities. The capital lease expense incurred consists of Amortization Expense (see Note 5) and Interest Expense—Capital Leases. The lease terms are described in Note 6.

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.

INVESTMENTS IN LEASE DEBT AND EQUITY

TEP held an investment in lease debt relating to Springerville Unit 1 through its maturity date in January 2013 and recorded this investment at amortized cost and recognized interest income. TEP holds a 14% equity interest in Springerville Unit 1 and a 7% interest in certain Springerville Common Facilities (Springerville Unit 1 Leases). The fair value of these investments is described in Note 15. These investments do not reduce the capital lease obligations reflected on the balance sheet because there is no legal right of offset. TEP makes lease payments to a trustee who then distributes the payments to the equity holders.

TEP accounts for its equity interest in the Springerville Unit 1 Lease trust using the equity method.

ASSET RETIREMENT OBLIGATIONS

TEP and UNS Electric have identified legal Asset Retirement Obligations (AROs) related to the retirement of certain generation assets. Additionally, TEP and UNS Electric incurred AROs related to their photovoltaic assets as a result of entering into various ground leases. 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. Beginning July 1, 2013, TEP began deferring costs associated with the majority of its legal AROs as regulatory assets because new depreciation rates approved in the 2013 TEP Rate Order include these costs.

Depreciation rates for all of our utilities 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. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees, and printing costs.

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 electricity and gas 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 not settled with energy, TEP and UNS Electric net the sales contracts with the purchase power contracts and reflect the net amount as Electric Wholesale Sales. The corresponding cash receipts are recorded in the statement of cash flows as Cash Receipts from Electric Wholesale Sales, while cash payments are recorded as Purchased Energy/Power Costs Paid.

TEP recognizes monthly management fees in Other Revenues as the operator of Springerville Unit 3 on behalf of Tri-State and Springerville Unit 4 on behalf of 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) associated with energy sales that no longer occur due to 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.

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.

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.

FUEL AND PURCHASED ENERGY COST RECOVERY MECHANISMS

TEP and UNS Electric Purchased Power and Fuel Adjustment Clause

TEP and UNS Electric recover actual fuel, purchased power and transmission costs incurred 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 and UNS Electric recover these costs. The difference between costs recovered through rates and actual fuel, purchased power and transmission costs prudently incurred 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 3.

UNS Gas Purchased Gas Adjustor

UNS Gas recovers actual gas costs incurred through a Purchased Gas Adjustor (PGA) mechanism that adjusts monthly. Gas cost over-recoveries are deferred as regulatory liabilities and under-recoveries are deferred as regulatory assets. See Note 3.

RENEWABLE ENERGY and ENERGY EFFICIENCY PROGRAMS

The ACC's Renewable Energy Standard (RES) requires TEP and UNS Electric to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025. The utilities must file annual RES implementation plans for review and approval by the ACC. The approved cost of carrying out those plans 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, UNS Electric, and UNS Gas are required to implement cost-effective Demand-Side Management (DSM) programs to comply with the ACC's Energy Efficiency (EE) Standards. The EE Standards provide for a DSM surcharge to recover, from retail customers, the costs to implement DSM programs. The Electric EE Standards require increasing annual targeted retail kWh savings equal to22% by 2020. The Gas EE Standards require increasing annual targeted retail therm sales equal to 6% 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 and UNS Electric recognize RES and DSM surcharge revenue in Electric Retail Sales in amounts necessary to offset recognized qualifying expenditures. Similarly, UNS Gas recognizes DSM surcharge revenue in Gas Retail Sales.

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 or UNS Electric 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 and UNS Electric record 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 and UNS Electric recognize Purchased Power expense and Other Revenues in an equal amount. See Note 3.

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 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 – Noncurrent includes income taxes recoverable through future rates, which reflects the future revenues due us from ratepayers as these tax benefits reverse. See Note 3.

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 are deferred as regulatory assets effective July 1, 2013 due to the 2013 TEP Rate Order. All other federal and state income tax credits are treated as a reduction to Income Tax Expense in the year the credit arises.

Consolidated income tax liabilities are allocated to subsidiaries based on their taxable income as reported in the 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.

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.

Cash Flow Hedges

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates related to the leveraged lease arrangements for the Springerville Common Lease and variable rate industrial development revenue or pollution control revenue bonds (IDBs). In addition, TEP hedges the cash flow risk associated with a long-term wholesale power supply agreement that does not qualify for regulatory recovery using a six-year power purchase swap agreement. UNS Electric uses a cash flow hedge to effectively convert the interest rate on the UNS Electric term loan from a variable rate to a fixed rate. TEP and UNS Electric account for cash flow hedges as follows:

- The effective portion of the change in the fair value is recorded in AOCI and the ineffective portion, if any, is recognized in earnings; and
- When TEP and UNS Electric determine a contract is no longer effective in offsetting the changes in cash flow of a hedged item, TEP and UNS Electric recognize the change in fair value in earnings. The unrealized gains and losses at that time remain in AOCI and are reclassified into earnings as the underlying hedged transaction occurs.

We formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives have been and are expected to remain highly effective in offsetting changes in the cash flows of hedged items.

Energy Contracts - Regulatory Recovery

TEP, UNS Electric and UNS Gas are authorized to recover the prudent costs of hedging activities entered into to mitigate energy price risk for retail customers. We record unrealized gains and losses on these energy derivatives as either a regulatory asset or regulatory liability to the extent they qualify for recovery through the PPFAC or PGA mechanism.

Master Netting Agreements

We have elected gross presentation for our derivative contracts under master netting agreements and collateral positions. We separate all derivatives into current and long-term portions on the balance sheet.

Normal Purchases and Normal Sales

We enter into forward energy purchase and sales contracts, including call options, with counterparties that have generating capacity to support our current load forecasts or counterparties that have load serving requirements. We have elected the normal purchase or normal sales exception for these contracts which are not required to be measured at fair value and are accounted for on an accrual basis.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commodity Trading
We did not engage in trading of derivative financial instruments.
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 sheets. 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 10.

NOTE 2. PENDING MERGER WITH FORTIS
On December 11, 2013, UNS Energy announced that it had entered into an agreement and plan of merger, subject to shareholder and required regulatory approvals, to be acquired by Fortis for $60.25 per share of Common Stock in cash. Following the merger, UNS Energy will continue as a wholly owned subsidiary of Fortis. The Board of Directors of each of UNS Energy and Fortis Parent have approved the merger.

NOTE 3. REGULATORY MATTERS
The Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (FERC) each regulate portions of the utility accounting practices and rates of TEP, UNS Electric, and UNS Gas. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, transactions with affiliated parties, and the pending merger. The FERC regulates terms and prices of transmission services and wholesale electricity sales, and the pending merger.
2013 TEP RATE ORDER
In June 2013, the ACC issued the 2013 TEP Rate Order that resolved the rate case filed by TEP in July 2012 which was based on a test year ended December 31, 2011. The 2013 TEP Rate Order approved new rates effective July 1, 2013.
The provisions of the 2013 TEP Rate Order include, but are not limited to:
- an increase in non-fuel retail Base Rates of approximately $76 million over adjusted test year revenues;
- an Original Cost Rate Base (OCRB) of approximately $1.5 billion and a Fair Value Rate Base (FVRB) of approximately $2.3 billion;
- a return on equity of 10.0%, a long-term cost of debt of 5.18%, and a short-term cost of debt of 1.42%, resulting in a weighted average cost of capital of 7.26%;
- a capital structure of approximately 43.5% equity, 56.0% long-term debt, and 0.5% short-term debt;
- a 0.68% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $800 million);

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

- a revision in depreciation rates from an average rate of 3.32% to 3.0% for generation and distribution plant, primarily due to revised estimates of asset removal costs, which will have the effect of reducing depreciation expense by approximately $11 million annually; and
- an agreement by TEP to seek recovery of costs related to the discontinued Nogales transmission project from the FERC before seeking rate recovery from the ACC.

The 2013 TEP Rate Order also includes the following cost recovery mechanisms:

- a new Purchased Power and Fuel Adjustment Clause (PPFAC) credit of 0.1388 cents per kWh effective July 1, 2013. The credit reflects the following:
  a reduction in the PPFAC bank balance, recorded in June 2013, as an increase to fuel expense, of $3 million related to prior sulfur credits; and
  a transfer of $10 million, recorded in June 2013, from the PPFAC bank balance to a new regulatory asset to defer coal costs related to the San Juan mine fire. These costs will be eligible for recovery through the PPFAC upon final settlement with the San Juan operator related to insurance proceeds.
- a modification of the PPFAC mechanism to include recovery of generation-related lime costs offset by sulfur credits.
- a Lost Fixed Cost Recovery mechanism (LFCR) to recover certain non-fuel costs related to kWh sales lost due to energy efficiency programs and distributed generation. In the fourth quarter of 2013, TEP recorded revenues of $2 million related to unrecovered non-fuel costs incurred during 2013.
- an Environmental Compliance Adjustor (ECA) mechanism to recover certain capital carrying costs to comply with government-mandated environmental regulations between rate cases. The ECA rate is capped at 0.025 cents per kWh, which approximates 0.25% of TEP's total retail revenues, and will be charged to customers beginning in May 2014 for any qualifying costs incurred between August 2013 and December 2013.
- an energy efficiency provision which includes a 2013 calendar year budget of approximately $21 million to fund programs that support the ACC's Electric Energy Efficiency Standards, as well as a $2 million performance incentive.

2013 UNS ELECTRIC RATE ORDER

In December 2013, the ACC issued the 2013 UNS Electric Rate Order that resolved the rate case filed by UNS Electric in December 2012 which was based on a test year ended June 30, 2012. The 2013 UNS Electric Rate Order approved new rates effective January 1, 2014.

The provisions of the 2013 UNS Electric Rate Order include, but are not limited to:

- an increase in non-fuel retail Base Rates of approximately $3 million;
- an OCRB of approximately $213 million and a FVRB of approximately $283 million;
- a return on equity of 9.50% and a long-term cost of debt of 5.97% resulting in a weighted average cost of capital of 7.83%;
- a 0.50% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $70 million); and
- a capital structure of 52.6% equity and 47.4% long-term debt.

The 2013 UNS Electric Rate Order also includes the following cost recovery mechanisms:

- a LFCR mechanism to recover certain non-fuel costs related to kWh sales lost due to energy efficiency programs and distributed generation; and
- a Transmission Cost Adjustor (TCA), which will allow more timely recovery of transmission costs associated with serving retail customers.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2012 UNS GAS RATE ORDER
In April 2012, the ACC approved a Base Rate increase of $2.7 million, or 1.8%, and an LFCR mechanism to enable UNS Gas to recover lost fixed cost revenues as a result of implementing the ACC's Gas Energy Efficiency Standards (Gas EE Standards).
The ACC approved an authorized rate of return of 8.3% on an OCRB of $183 million, and a 1.0% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and FVRB of approximately $70 million). The new rates became effective in May 2012.
COST RECOVERY MECHANISMS
TEP, UNS Electric, and UNS Gas have 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 (unless otherwise approved by the ACC) and goes into effect for the subsequent 12-month period unless suspended by the ACC.
TEP's PPFAC rate includes: 1) a forward component, under which TEP recovers or refunds differences between a) forecasted fuel, transmission, and purchased power costs for the upcoming calendar year and b) those embedded in the fuel rate and the current PPFAC rates; and 2) a true-up component, which reconciles differences between prudently incurred actual fuel, transmission, and purchased power costs and those recovered through the combination of the fuel rate and the forward component for the preceding 12-month period.
Prior to the 2013 UNS Electric Rate Order, UNS Electric's PPFAC rate was adjusted annually each June 1st, effective for the subsequent 12-month period. As a result of the 2013 UNS Electric Rate Order, effective January 1, 2014, UNS Electric's PPFAC rate reflects a weighted 12-month rolling average of actual fuel and purchased power costs incurred by UNS Electric. The PPFAC rate adjusts monthly, but it is restricted from changing by more than 0.83 percent from the preceding month's rate. If the PPFAC deferral balance reflects an over-collection of $10 million or more on a billed-to-customer basis, UNS Electric must file for a PPFAC rate adjustment. At December 31, 2013, the PPFAC bank balance was over-collected by $14 million on a billed-to-customer basis.
The tables below summarize TEP's and UNS Electric's PPFAC rates:

	TEP 2013 July - December	 January - June	 2012 April - December	 January - March
	Cents per kWh			
PPFAC Rate	0.14	0.77	0.77	0.53
Competition Transition Charge [1]	—	—	—	(0.53)
Net TEP PPFAC Rate	0.14	0.77	0.77	—

(1) TEP's PPFAC became effective January 1, 2009. However, TEP was initially required to refund amounts to customers through the PPFAC mechanism that were over collected under the Competition Transition Charge (CTC) in place from 1999 through 2008. As a result, the authorized net PPFAC charge was set at zero until all over collected CTC revenue was fully refunded to customers (November 2011). TEP then continued deferring PPFAC eligible costs but was not authorized to bill customers until a new PPFAC rate was approved by the ACC in April 2012.

	UNS Electric 2013 September - December	 June - August	 January - May	 2012 June - December	 January - May
	Cents per kWh				
PPFAC Rate	(0.40)	(0.92)	(1.44)	(1.44)	(0.88)

UNS Gas Purchased Gas Adjustor

The PGA mechanism allows UNS Gas to adjust Retail Rates to recover fluctuations in natural gas costs. UNS Gas records deferrals for recovery or refund to the extent actual natural gas costs vary from the PGA rate. The PGA rate reflects a weighted, rolling average of the gas costs incurred by UNS Gas over the preceding 12 months. The PGA rate automatically adjusts monthly, but it is restricted from rising or falling more than 15 cents per therm in a twelve-month period. UNS Gas is required to request an additional surcredit if deferral balances reflect $10 million or more on a billed-to-customer basis.

In October 2013, the ACC approved an increase to the existing PGA credit from 4.5 cents per therm to 10 cents per therm in order to reduce the over-collected PGA bank balance. The new PGA credit will be effective for the period November 1, 2013 through April 30, 2014. At December 31, 2013 and December 31, 2012, the PGA bank balance was over-collected by $10 million on a billed-to-customer basis.

The PGA rate ranged from 0.4504 to 0.5280 cents per therm in 2013, and ranged from 0.5202 to 0.6501 cents per therm in 2012.

Renewable Energy Standards

TEP and UNS Electric are required to expand their use of renewable energy in order to meet the ACC's RES. TEP and UNS Electric, through a customer surcharge, recover costs associated with meeting the RES. These costs include the purchases of RECs through Power Purchase Agreements (PPAs) and Performance Based Incentives (PBIs), as well as costs associated with utility-scale ownership of solar assets until the projects can be incorporated in Base Rates.

In October 2013, the ACC approved TEP's 2014 RES plan and authorized a total 2014 RES budget of $40 million with $34 million to be collected through the 2014 RES funding mechanism. TEP earned returns on solar investments of $2 million in each of 2013 and 2012 and $1 million in 2011.

In October 2013, the ACC approved UNS Electric's 2014 RES plan and authorized a total 2014 RES budget of $7 million with $6 million to be collected through the 2014 RES funding mechanism. UNS Electric earned returns on solar investments of less than $0.5 million in 2013 and 2012. No return was earned in 2011.

Energy Efficiency Standards

TEP, UNS Electric, and UNS Gas are required to implement cost-effective 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.

In December 2013, the ACC approved UNS Electric's 2013-2014 energy efficiency implementation plan that included a 2014 calendar year budget of approximately $5 million to fund programs that support the ACC's Electric EE Standards as well as a performance incentive.

In June 2013, the ACC approved the UNS Gas 2011-2012 energy efficiency implementation plan with certain modifications. The approval included an annual energy efficiency budget of approximately $2 million and a waiver of the Gas EE Standards through 2013.

Lost Fixed Cost Recovery Mechanism

The LFCR is a mechanism to recover certain non-fuel costs that would go unrecovered due to lost sales as a result of implementing ACC approved EE Standards and distributed generation targets.

In April 2012, the ACC authorized a LFCR mechanism that enables UNS Gas to recover non-purchased energy related costs that would go unrecovered due to lost therm sales as a result of implementing the Gas EE Standards.

In June 2013, the ACC authorized a LFCR mechanism for TEP subject to a year-over-year cap of 1% of TEP's total retail revenues. TEP expects the LFCR rate which will recover 2013 costs, to be effective on July 1, 2014, upon review by the ACC of verified lost kWh sales.

In December 2013, as part of the 2013 UNS Electric Rate Order, the ACC authorized a LFCR for UNS Electric, to be effective on July 1, 2014.

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REGULATORY ASSETS AND LIABILITIES

The following tables summarize regulatory assets and liabilities:

	December 31, 2013			
	TEP	UNS Electric	UNS Gas	UNS Energy
	Millions of Dollars			
Regulatory Assets—Current				
Property Tax Deferrals [1]	$20	$—	$—	$20
Derivative Instruments (Note 15)	1	—	—	1
San Juan Mine Fire Cost Deferral [2]	10	—	—	10
PPFAC [2]	4	10	—	14
DSM and LFCR [2]	3	—	—	3
Other Current Regulatory Assets [3]	5	—	—	5
Total Regulatory Assets—Current	43	10	—	53
Regulatory Assets—Noncurrent				
Pension and Other Retiree Benefits (Note 10)	75	3	2	80
Income Taxes Recoverable through Future Revenues [4]	22	3	—	25
PPFAC—Final Mine Reclamation and Retiree Health Care Costs [5]	25	—	—	25
Discontinued Nogales Transmission Project [6]	5	—	—	5
Other Regulatory Assets [3]	14	2	—	16
Total Regulatory Assets—Noncurrent	141	8	2	151
Regulatory Liabilities—Current				
PGA [2]	—	—	(15)	(15)
RES [2]	(22)	(9)	—	(31)
Other Current Regulatory Liabilities	(2)	(6)	—	(8)
Total Regulatory Liabilities—Current	(24)	(15)	(15)	(54)
Regulatory Liabilities—Noncurrent				
Net Cost of Removal for Interim Retirements [7]	(254)	(12)	(26)	(292)
Income Taxes Payable through Future Rates	(5)	—	(1)	(6)
Deferred Investment Tax Credit [8]	(4)	—	—	(4)
Total Regulatory Liabilities—Noncurrent	(263)	(12)	(27)	(302)
Total Net Regulatory Assets (Liabilities)	$(103)	$(9)	$(40)	$(152)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2012			
	TEP	UNS Electric	UNS Gas	UNS Energy
	Millions of Dollars			
Regulatory Assets—Current				
Property Tax Deferrals [1]	$18	$—	$—	$18
Derivative Instruments (Note 15)	2	6	3	11
PPFAC [2]	7	8	—	15
DSM [2]	5	—	—	5
Other Current Regulatory Assets [3]	2	—	1	3
Total Regulatory Assets—Current	34	14	4	52
Regulatory Assets—Noncurrent				
Pension and Other Retiree Benefits (Note 10)	130	5	4	139
Income Taxes Recoverable through Future Revenues [4]	8	2	—	10
PPFAC—Final Mine Reclamation and Retiree Health Care Costs [5]	22	—	—	22
Discontinued Nogales Transmission Project [6]	5	—	—	5
Other Regulatory Assets [3]	13	1	1	15
Total Regulatory Assets—Noncurrent	178	8	5	191
Regulatory Liabilities—Current				
PGA [2]	—	—	(17)	(17)
RES [2]	(19)	(4)	—	(23)
Other Current Regulatory Liabilities	(2)	(1)	(1)	(4)
Total Regulatory Liabilities—Current	(21)	(5)	(18)	(44)
Regulatory Liabilities—Noncurrent				
Net Cost of Removal for Interim Retirements [7]	(231)	(11)	(25)	(267)
Income Taxes Payable through Future Rates	(5)	—	(1)	(6)
Deferred Investment Tax Credit [8]	(5)	—	—	(5)
Other Regulatory Liabilities	—	(1)	—	(1)
Total Regulatory Liabilities—Noncurrent	(241)	(12)	(26)	(279)
Total Net Regulatory Assets (Liabilities)	$(50)	$5	$(35)	$(80)

Regulatory assets are either being collected in Retail Rates or are expected to be collected through Retail Rates in a future period. We describe regulatory assets below. With the exception of interest earned on under-recovered PPFAC costs, we do not earn a return on regulatory assets.

(1) Property Tax is recovered over approximately a six-month period as costs are paid, rather than as costs are accrued.

(2) See Cost Recovery Mechanisms discussion above.

(3) TEP's other regulatory assets include unamortized loss on reacquired debt (recovery through 2032), coal contract amendment (recovery through 2017), rate case costs (recovery over three years), environmental compliance costs, Springerville Unit 1 lease deferrals and other assets (recovery through 2014).

(4) Income Taxes Recoverable through Future Revenues are amortized over the life of the assets.

(5) Final Mine Reclamation and Retiree Health Care Costs stem from TEP's jointly-owned facilities at the San Juan Generating Station, the Four Corners Generating Station, and the Navajo Generating Station. TEP is required to recognize the present value of its liability associated with final mine reclamation and retiree health care obligations over the life of the coal supply agreements. TEP recorded a regulatory asset because TEP is permitted to fully recover these costs through the PPFAC when the costs are invoiced by the miners. TEP expects to recover these costs over the remaining life of the mines, which is estimated to be between 14 and 20 years.

(6) TEP and UNS Electric will request recovery from FERC for the prudent costs incurred to develop a high-voltage transmission line from Tucson to Nogales. TEP and UNS Electric are not going to proceed with the project. See Note 7.

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, as described below:

(7) Net Cost of Removal for Interim Retirements represents amounts recovered through depreciation rates associated with asset retirement costs expected to be incurred in the future.

(8) The Deferred Investment Tax Credit relates to federal energy credits generated in 2012 and is 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 4. BUSINESS SEGMENTS

We have three reportable segments regularly reviewed by our chief operating decision makers to evaluate performance and make operating decisions.

(1) TEP, a regulated electric utility and our largest subsidiary
(2) UNS Electric, a regulated electric utility
(3) UNS Gas, a regulated gas distribution utility

We disclose selected financial data for our reportable segments in the following tables:

	Reportable Segments					
	TEP	UNS Electric	UNS Gas	Other [2]	Reconciling Adjustments	UNS Energy
	Millions of Dollars					
2013						
Income Statement						
Operating Revenues-External	$1,180	$174	$131	$2	$(2)	$1,485
Operating Revenues-Intersegment [1]	17	2	3	17	(39)	—
Depreciation and Amortization	149	19	9	—	—	177
Interest Income	—	1	—	—	—	1
Interest Expense	79	7	6	1	—	93
Income Tax Expense	48	7	7	(4)	—	58
Net Income	101	12	11	3	—	127
Cash Flow Statement						
Capital Expenditures	(253)	(56)	(17)	—	—	(326)
Balance Sheet						
Total Assets	3,556	404	311	1,194	(1,192)	4,273

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Reportable Segments					
	TEP	UNS Electric	UNS Gas	Other [2]	Reconciling Adjustments	UNS Energy
	Millions of Dollars					
2012						
Income Statement						
Operating Revenues-External	$1,145	$189	$129	$—	$(1)	$1,462
Operating Revenues-Intersegment [1]	17	1	4	18	(40)	—
Depreciation and Amortization	150	18	9	—	—	177
Interest Income	—	—	—	1	—	1
Interest Expense	88	8	6	3	—	105
Income Tax Expense	39	11	6	—	—	56
Net Income	65	17	9	—	—	91
Cash Flow Statement						
Capital Expenditures	(253)	(38)	(16)	—	—	(307)
Balance Sheet						
Total Assets	3,461	370	310	1,121	(1,122)	4,140
2011						
Income Statement						
Operating Revenues-External	$1,141	$188	$149	$—	$1	$1,479
Operating Revenue-Intersegment [1]	15	2	2	23	(42)	—
Depreciation and Amortization	140	17	8	1	(1)	165
Interest Income	4	—	—	1	—	5
Interest Expense	89	7	7	9	—	112
Income Tax Expense	52	11	7	(1)	(2)	67
Net Income	85	18	10	—	(3)	110
Cash Flow Statement						
Capital Expenditures	(352)	(96)	(13)	(34)	121	(374)

(1) Operating Revenues – Intersegment includes common costs (system, facilities, etc.) allocated to affiliates on a cost-causative basis and recorded as revenue by TEP, sales of power between TEP and UNS Electric at third-party market prices, control area services provided by TEP to UNS Electric based on a FERC-approved tariff, sales of gas by UNS Gas at third-party market prices for use in UNS Electric's generating facilities, and supplemental workforce charges charges (primarily meter reading services) provided to the utilities by an unregulated affiliate.

(2) Other includes the UNS Energy and UES holding companies, Millennium, and UED.

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NOTE 5. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

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

	UNS Energy		TEP	
	December 31,		December 31,	
	2013	2012	2013	2012
	Millions of Dollars			
Plant in Service:				
Electric Generation Plant	$1,974	$1,932	$1,889	$1,847
Electric Transmission Plant	912	842	825	796
Electric Distribution Plant	1,529	1,495	1,298	1,271
Gas Distribution Plant	252	240	—	—
Gas Transmission Plant	18	18	—	—
General Plant	356	347	312	309
Intangible Plant - Software Costs (1) (2)	142	124	141	123
Intangible Plant - Other	5	5	—	—
Electric Plant Held for Future Use	4	3	3	2
Total Plant in Service	$5,192	$5,006	$4,468	$4,348
Utility Plant under Capital Leases(3)	$638	$583	$638	$583

(1) Unamortized computer software costs were $40 million for UNS Energy and $39 million for TEP as of December 31, 2013, and $36 million for UNS Energy and $35 million for TEP as of December 31, 2012.

(2) The amortization of computer software costs in UNS Energy’s and TEP's income statements was $14 million in 2013, $13 million in 2012, and $10 million in 2011.

(3) In 2013, TEP entered into agreements to purchase certain Springerville Unit 1 leased interests. See Note 6.

TEP Utility Plant under Capital Leases

All TEP utility plant under capital leases is used in TEP’s generation operations and amortized over the primary lease term. See Note 6. At December 31, 2013, the utility plant under capital leases includes: 1) Springerville Unit 1; 2) Springerville Common Facilities; and 3) Springerville Coal Handling Facilities. The following table shows the amount of lease expense incurred for TEP’s generation-related capital leases:

	Years Ended December 31,		
	2013	2012	2011
	Millions of Dollars		
Lease Expense:			
Interest Expense – Included in:			
Capital Leases	25	$34	$40
Operating Expenses – Fuel	2	3	4
Other Expense	—	—	1
Amortization of Capital Lease Assets – Included in:			
Operating Expenses – Fuel	5	4	3
Operating Expenses – Amortization	15	14	14
Total Lease Expense	$47	$55	$62

Utility plant depreciation rates and approximate average remaining service lives based on the most recent depreciation studies available at December 31, 2013, were as follows:

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	TEP December 31, 2013 Annual Depreciation Rate [5]	Average Remaining Life in Years
Major Class of Utility Plant in Service:		
Electric Generation Plant [1]	3.31%	22
Electric Transmission Plant	1.48%	32
Electric Distribution Plant [1]	2.08%	35
General Plant [1]	5.48%	11
Intangible Plant [2]	Various	Various

	UNS Electric December 31, 2013 Annual Depreciation Rate [5]	Average Remaining Life in Years
Major Class of Utility Plant in Service:		
Electric Generation Plant	2.56%	36
Electric Transmission Plant	3.36%	19
Electric Distribution Plant	3.97%	15
General Plant	8.01%	7
Intangible Plant [3]	Various	Various

	UNS Gas December 31, 2013 Annual Depreciation Rate [5]	Average Remaining Life in Years
Major Class of Utility Plant in Service:		
Gas Generation Plant	2.37%	41
Gas Transmission Plant	1.54%	54
General Plant	4.38%	7
Intangible Plant [4]	Various	Various

(1) In June 2013, the ACC issued the 2013 TEP Rate Order that approved a change in depreciation rates which reflects changes in the remaining average useful lives for our generation, distribution, and general plant assets. See Note 3.

(2) The majority of TEP's investment in intangible plant represents computer software, which is being amortized over its expected useful life based on either the average lives of 3 to 5 years for smaller application software or remaining lives ranging from 5 to 19 years for large enterprise software.

(3) UNS Electric's intangible plant primarily represents capitalized interconnection costs, which are amortized based on either an average life of 23 years or a remaining life of 35 years.

(4) UNS Gas' intangible plant consists of miscellaneous intangible assets, which are amortized over an average life of either 15 or 25 years.

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

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JOINTLY-OWNED FACILITIES

At December 31, 2013, TEP's interests in jointly-owned generating stations and transmission systems were as follows:

	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Book Value
		Millions of Dollars			
San Juan Units 1 and 2	50.0%	$448	$6	$230	$224
Navajo Units 1, 2, and 3	7.5%	152	1	110	43
Four Corners Units 4 and 5	7.0%	101	2	75	28
Luna Energy Facility	33.3%	53	—	2	51
Transmission Facilities	Various	330	43	190	183
Total		$1,084	$52	$607	$529

TEP is responsible for its share of operating costs for the above facilities as well as providing financing. TEP accounts for its share of operating expenses and utility plant costs related to these facilities using proportionate consolidation.

ASSET RETIREMENT OBLIGATIONS

The accrual of AROs is primarily related to generation and photovoltaic assets and is included in Deferred Credits and Other Liabilities on the balance sheets. The following table reconciles the beginning and ending aggregate carrying amounts of ARO accruals on the balance sheets:

	UNS Energy December 31, 2013	2012
	Millions of Dollars	
Beginning Balance	$14	$13
Liabilities Incurred	1	—
Accretion Expense or Regulatory Deferral	1	1
Revisions to the Present Value of Estimated Cash Flows (1)	7	—
Ending Balance	$23	$14

(1) Primarily related to changes in expected retirement dates of generating facilities.

The table above primarily reflects TEP's ARO obligations. UNS Electric's ARO obligations were less than $1 million at December 31, 2013 and 2012.

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

Long-term debt matures more than one year from the date of the financial statements. We summarize UNS Energy's and TEP's long-term debt in the statements of capitalization.

UNS ENERGY CONVERTIBLE SENIOR NOTES

In 2005, UNS Energy issued $150 million of 4.50% Convertible Senior Notes due in 2035. In 2012, UNS Energy converted approximately $147 million of the Convertible Senior Notes into approximately 4.3 million shares of Common Stock and redeemed $3 million for cash.

TEP DEBT ISSUANCES AND REDEMPTIONS

Unsecured Tax-Exempt Variable Rate Bonds

In November 2013, the Industrial Development Authority of Apache County, Arizona issued $100 million of tax-exempt, variable rate Industrial Development Revenue Bonds (IDRBs), due April 2032. The lender resets the interest rate monthly based on a percentage of an index rate equal to one-month LIBOR plus a bank margin rate; the rate at December 31, 2013 was

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0.948% per annum. These bonds are multi-modal bonds, and the initial term is set at five years through November 2018, at which time the bonds will be subject to mandatory tender for purchase. Proceeds were deposited with a trustee to redeem $100 million variable rate bonds in December 2013.

Secured Tax-Exempt Variable Rate Bonds and Interest Rate Swap

Certain of TEP's tax-exempt, variable rate bonds are secured by Letter of Credits (LOCs) issued under the TEP Credit Agreement and TEP Reimbursement Agreement, see below.

The following table shows interest rates on TEP’s weekly variable rate bonds, which are reset weekly by its remarketing agents:

	Years Ended December 31,		
	2013	2012	2011
Interest Rates on Bonds:			
Average Interest Rate	0.10%	0.17%	0.18%
Range of Average Weekly Rates	0.06% - 0.25%	0.06% - 0.26%	0.05% - 0.34%

In August 2009, TEP entered into an interest rate swap that had the effect of converting $50 million of variable rate bonds to a fixed rate of 2.4% from September 2009 to September 2014.

Unsecured Tax-Exempt Fixed Rate Bonds

In March 2013, TEP issued approximately $91 million aggregate principal amount of Pima County, Arizona, unsecured tax-exempt Industrial Development Bonds (IDBs). The bonds bear interest at a fixed rate of 4.0%, mature in September 2029, and may be redeemed at par on or after March 1, 2023. The proceeds from the sale of the bonds were deposited with a trustee to retire approximately $91 million of 6.375% unsecured tax-exempt bonds in April 2013.

In June 2012, TEP issued approximately $16 million of Pima County, Arizona, unsecured tax-exempt IDBs. The bonds bear interest at a fixed rate of 4.5%, mature in June 2030, and may be redeemed at par on or after June 1, 2022. The proceeds from the sale of the bonds were deposited with a trustee to retire approximately $16 million of unsecured, tax-exempt bonds with interest rates of 5.85% and 5.875%, and maturity dates ranging from 2026 to 2033.

In March 2012, TEP issued $177 million of Apache County, Arizona, unsecured, tax-exempt pollution control bonds. The bonds bear interest at a fixed rate of 4.5%, mature in March 2030, and may be redeemed at par on or after March 1, 2022. The proceeds from the sale of the bonds, together with $7 million of principal and $1 million for accrued interest provided by TEP, were deposited with a trustee to retire $184 million of unsecured tax-exempt bonds with interest rates of 5.85% and 5.875% and maturity dates ranging from 2026 to 2033.

Unsecured Fixed Rate Notes

In September 2012, TEP issued $150 million of 3.85% unsecured notes due March 2023. TEP may call the debt prior to December 15, 2022, with a make-whole premium plus accrued interest. After December 15, 2022, TEP may call the debt at par plus accrued interest. The unsecured notes contain a limitation on the amount of secured debt that TEP may have outstanding. TEP used the net proceeds to repay approximately $72 million outstanding on the revolving credit facility, with the remaining proceeds used for general corporate purposes.

TEP MORTGAGE INDENTURE

Prior to November 2013, the TEP Credit Agreement and the 2010 TEP Reimbursement Agreement were secured by $423 million in mortgage bonds issued under the 1992 Mortgage. As a result of TEP's credit rating upgrade, in October 2013, TEP canceled $423 million in mortgage bonds and discharged the 1992 Mortgage, which had created a lien on and security interest in substantially all of TEP’s utility plant assets. TEP’s obligations under the TEP Credit Agreement and the 2010 TEP Reimbursement Agreement are now unsecured.

UNS ENERGY CREDIT AGREEMENT

The UNS Energy Credit Agreement consists of a $125 million revolving credit facility and revolving LOC facility and expires in November 2016. UNS Energy’s obligations under the agreement are secured by a pledge of the capital stock of Millennium, UES, and UED.

UNS Energy had $54 million of outstanding borrowings at December 31, 2013 and $45 million of outstanding borrowings at December 31, 2012, under its revolving credit facility. The weighted average interest rate on the revolver was 1.66% at

December 31, 2013 and 1.96% at December 31, 2012. We report the revolver borrowings in Long-Term Debt on the balance sheet as UNS Energy has the ability and the intent to have outstanding borrowings for the next twelve months. As of February 14, 2014, outstanding borrowings under the UNS Energy Credit Agreement totaled $52 million.
Interest rates and fees under the UNS Energy Credit Agreement are based on a pricing grid tied to UNS Energy's credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.25% for Eurodollar loans or Alternate Base Rate plus 0.25% for Alternate Base Rate loans.

TEP CREDIT AGREEMENT

The TEP Credit Agreement consists of a $200 million revolving credit, revolving LOC facility, and a $82 million LOC facility to support tax-exempt bonds, and expires in November 2016. In December 2013, TEP reduced its letter of credit facility from $186 million to $82 million, following the refinancing of $100 million of variable rate bonds and the cancellation of $104 million of LOCs supporting those bonds.
Interest rates and fees under the TEP 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 1.125% for Eurodollar loans or Alternate Base Rate plus 0.125% for Alternate Base Rate loans. The margin rate currently in effect on the $82 million LOC facility is 1.125%.
TEP had no borrowings and $1 million outstanding in LOCs issued under its revolving credit facility at December 31, 2013 and December 31, 2012. The revolving loan balance was included in Current Liabilities on UNS Energy's and TEP's balance sheets. The outstanding LOCs are off-balance sheet obligations of TEP. As of February 14, 2014, TEP had $90 million in borrowings and $1 million outstanding in LOCs under its revolving credit facility.

2010 TEP REIMBURSEMENT AGREEMENT

A $37 million LOC was issued pursuant to the 2010 TEP Reimbursement Agreement. The LOC supports $37 million aggregate principal amount of variable rate tax-exempt bonds that were issued on behalf of TEP in December 2010. In February 2014, TEP amended the agreement to extend the LOC expiration date from 2014 to 2019. Fees are payable on the aggregate outstanding amount of the LOC at a rate of 1.00% per annum.

UNS ELECTRIC/UNS GAS CREDIT AGREEMENT

The UNS Electric/UNS Gas Credit Agreement consists of a $100 million revolving credit and revolving LOC facility, and expires in November 2016. The maximum borrowings outstanding at any one time for UNS Gas or UNS Electric under the agreement may not exceed $70 million. UNS Electric and UNS Gas each are liable for only their own individual borrowings under the UNS Electric/UNS Gas Credit Agreement. UES guarantees the obligations of both UNS Electric and UNS Gas. The UNS Electric/UNS Gas Credit Agreement may be used to issue LOCs, as well as for revolver borrowings. UNS Electric and UNS Gas issue LOCs, which are off-balance sheet obligations, to support power and gas purchases and hedges.
Interest rates and fees under the UNS Electric/UNS Gas Credit Agreement are based on a pricing grid tied to their credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.125% for Eurodollar loans or Alternate Base Rate plus 0.125% for Alternate Base Rate loans.
UNS Electric had $22 million in borrowings and less than $0.5 million in outstanding LOCs under the UNS Electric/UNS Gas Credit Agreement as of December 31, 2013. The revolving loan balance was included in Current Liabilities on UNS Energy's balance sheet. UNS Electric had no borrowings outstanding and less than $0.5 million LOCs under UNS Electric/UNS Gas Credit Agreement as of December 31, 2012. The oustanding LOCs balances are not shown on the balance sheet. As of February 14, 2014, UNS Electric had $25 million in borrowings and less than $0.5 million in outstanding LOCs under the UNS Electric/UNS Gas Credit Agreement.

UNS ELECTRIC TERM LOAN CREDIT AGREEMENT AND INTEREST RATE SWAP

In August 2011, UNS Electric entered into a four-year $30 million variable rate term loan credit agreement. The interest rate currently in effect is three-month LIBOR plus 1.125%. At the same time, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a $30 million notional amount over a four years period ending August 2015. The UNS Electric term loan credit agreement, included in Long-Term Debt on the balance sheet, is guaranteed by UES.

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COVENANT COMPLIANCE

Our credit agreements, the 2010 TEP Reimbursement Agreement, and certain of our 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. The UNS Energy Credit Agreement also requires UNS Energy to meet a minimum cash flow to interest coverage ratio, and each of our credit agreements stipulate a maximum leverage ratio. UNS Energy and its subsidiaries may pay dividends so long as we maintain compliance with our credit agreements.

At December 31, 2013, we were in compliance with the terms of our long-term debt, credit agreements, and the 2010 TEP Reimbursement Agreement. No amounts of net income were subject to dividend restrictions.

TEP CAPITAL LEASE OBLIGATIONS

In January 2014, through scheduled lease payments, TEP reduced its capital lease obligations by $80 million.

Springerville Unit 1 Capital Lease Purchase Commitments

The Springerville Unit 1 Leases have an initial term to January 2015, and include a fair market value purchase option at the end of the initial lease term. In 2011, TEP and the owner participants of Springerville Unit 1 completed a formal appraisal procedure to determine the fair market value purchase price of Springerville Unit 1 in accordance with the Springerville Unit 1 Leases. The purchase price was determined to be $478 per kW of capacity based on a capacity rating of 387 MW.

In August 2013, TEP elected to purchase 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 the expiration of the lease term in January 2015.

In October 2013, TEP elected to purchase an additional 10.6% leased interest in Springerville Unit 1, representing 41 MW of capacity, for $20 million, the appraised value, with the purchase scheduled to occur in December 2014.

Upon close of these lease option purchases, TEP will own 49.5% of Springerville Unit 1, or 192 MW of capacity. Due to TEP's purchase commitments, TEP and UNS Energy recorded an increase of approximately $55 million to both Utility Plant Under Capital Leases and Capital Lease Obligations on their balance sheets.

Springerville Coal Handling and Common Facilities Leases

The Springerville Coal Handling Facilities Leases have an initial term to April 2015 and provide for fixed-rate lease renewal options if certain conditions are satisfied as well as a fixed-price purchase provision of $120 million. The leases provide for one renewal period of six years beginning in April 2015, with additional renewal periods of five or more years through 2035.

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 a fixed-price purchase provision. The fixed prices for the acquisition of the common facilities are $38 million in 2017 and $68 million in 2021.

TEP agreed with Tri-State, the owner of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities and Common Facilities Leases are not renewed, TEP will exercise the purchase options under these contracts. SRP will then be obligated to buy a portion of these facilities and Tri-State will then be obligated to either: buy a portion of these facilities; or continue making payments to TEP for the use of these facilities.

Lease Debt and Equity

Investments in Springerville Lease Debt and Equity

In January 2013, TEP received the final maturity payment of $9 million on the investment in Springerville Unit 1 lease debt. TEP also held an undivided equity ownership interest in the Springerville Unit 1 Leases totaling $36 million at December 31, 2013 and December 31, 2012.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Swaps—Springerville Common Facilities Lease Debt

TEP's interest rate swaps hedge the floating interest rate risk associated with the Springerville Common Facilities lease debt. Interest on the lease debt is payable at six-month London Interbank Offered Rate (LIBOR) plus a spread. The applicable spread was 1.75% at December 31, 2013 and December 31, 2012.

The swaps have the effect of fixing the interest rates on the amortizing principal balances as follows:

Lease Debt Outstanding at December 31, 2013	Fixed Rate	LIBOR Spread
Swap 1 - Notional Amount $33 million - Effective Date June 2006	5.77 %	1.75 %
Swap 2 - Notional Amount $16 million - Effective Date May 2009	3.18 %	1.75 %
Swap 3 - Notional Amount $6 million - Effective Date May 2009	3.32 %	1.75 %

TEP recorded these interest rate swaps as a cash flow hedge for financial reporting purposes. See Note 15.

DEBT MATURITIES

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

	TEP Long-Term Debt Maturities [(1)]	TEP Capital Lease Obligations	TEP Total	UNS Electric	UNS Gas	UNS Energy Parent Company	Total
	Millions of Dollars						
2014	$—	$214	$214	$—	$—	$—	$214
2015	—	69	69	80	50	—	199
2016	78	17	95	—	—	54	149
2017	—	18	18	—	—	—	18
2018	100	11	111	—	—	—	111
Total 2014 – 2018	178	329	507	80	50	54	691
Thereafter	1,046	30	1,076	50	50	—	1,176
Less: Imputed Interest	—	(42)	(42)	—	—	—	(42)
Total	$1,224	$317	$1,541	$130	$100	$54	$1,825

(1) $115 million of TEP's variable rate bonds are backed by LOCs issued pursuant to TEP's Credit Agreement, which expires in November 2016, and TEP's Reimbursement Agreement, which expires in December 2019. Although the variable rate bonds mature between 2022 and 2032, the above table reflects a redemption or repurchase of such bonds in 2016 and 2019 as though the LOCs terminate without replacement upon expiration of the TEP Credit Agreement. TEP's 2013 tax-exempt variable rate IDBs, which mature in 2032, are subject to mandatory tender for purchase after the current five-year term and are therefore reflected as maturing in 2018. The repayment of TEP Unsecured Notes is not reduced by the approximately $1 million discount.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 7. COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL MATTERS
COMMITMENTS
At December 31, 2013, UNS Energy and TEP had the following firm, non-cancelable, minimum purchase obligations and operating leases. UNS Energy's commitments represent the obligations of TEP, UNS Electric, and UNS Gas:

	UNS Energy Purchase Commitments						
	2014	2015	2016	2017	2018	Thereafter	Total
	Millions of Dollars						
Fuel, Including Transportation	$103	$83	$80	$75	$49	$345	$735
Purchased Power	75	17	—	—	—	—	92
Transmission	7	13	12	12	11	27	82
Renewable Power Purchase Agreements	36	37	37	37	37	485	669
RES Performance-Based Incentives	9	9	9	9	9	85	130
Operating Leases	4	4	3	2	2	14	29
Total Purchase Commitments	$234	$163	$141	$135	$108	$956	$1,737

At December 31, 2013, TEP had the following firm, non-cancelable, minimum purchase obligations and operating leases:

	TEP Purchase Commitments						
	2014	2015	2016	2017	2018	Thereafter	Total
	Millions of Dollars						
Fuel, Including Transportation	$77	$63	$64	$62	$36	$285	$587
Purchased Power	27	5	—	—	—	—	32
Transmission	3	6	6	6	6	21	48
Renewable Power Purchase Agreements	30	31	31	31	31	410	564
RES Performance-Based Incentives	8	8	8	8	8	83	123
Operating Leases	3	3	2	2	2	14	26
Total Purchase Commitments	$148	$116	$111	$109	$83	$813	$1,380

Fuel
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.

UNS Gas purchases gas from various supplies at market prices. However, UNS Gas' risk of loss due to increased costs is mitigated through the use of the PGA, which provides for the pass-through of actual commodity costs to customers. UNS Gas' forward gas purchase agreements expire through 2016. Certain of these contracts are at a fixed price per Million British Thermal Units (MMbtu) and others are indexed to natural gas prices. The commitment amounts included in the table are based on projected marked prices as of December 31, 2013. UNS Gas has firm transportation agreements with capacity sufficient to meet its load requirements. These contracts expire in various years between 2016 and 2023.

Purchased Power and Transmission
TEP and UNS Electric have 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. These contracts expire in 2014 and 2015. 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, 2013.

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TEP has agreements with other utilities to provide transmission services. These contracts expire in various years between 2018 and 2028. UNS Electric imports the power it purchases over the Western Area Power Administration's (WAPA) transmission lines. UNS Electric's transmission capacity agreements with WAPA provide for annual rate adjustments and expire in 2016.

TEP's and UNS Electric's purchased power and transmission costs are recoverable from customers through their respective PPFAC mechanisms.

Renewable Power Purchase Agreements and RES Performance-Based Incentives

TEP and UNS Electric have entered into 20 year Renewable Power Purchase Agreements (PPAs) which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generation facilities that have achieved commercial operation. TEP has entered into additional long-term renewable PPAs to comply with RES requirements; however, TEP’s obligation to purchase power under these agreements does not begin until the facilities are operational. A portion of the cost of renewable energy is recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. See Note 3.

TEP and UNS Electric have 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 3.

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. UNS Energy's operating lease expense totaled $3 million in each of 2013, 2012, and 2011, and TEP's operating lease expense totaled $2 million in each of 2013, 2012, and 2011.

TEP CONTINGENCIES

Potential Purchase of Gas-Fired Generation Facility

In 2013, TEP and UNS Electric entered into an agreement to purchase a gas-fired generation facility; see Note 8.

Claim Related to San Juan Generating Station

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

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

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against Arizona Public Service Company (APS) and the other Four Corners Generating Station (Four Corners) participants alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. In January 2012, EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners. Among other things, the plaintiffs seek to have the court issue an order to cease operations at Four Corners until any required PSD permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint. The joint participants have applied to have the matter stayed until March 17, 2014 in furtherance of settlement talks.

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. TEP cannot predict the final outcome of the claims relating to Four Corners, and, due to the general and non-specific nature of the claims and the indeterminate scope and nature of the injunctive relief sought for this claim, TEP cannot determine estimates of the range of loss at this time. TEP accrued estimated losses of less than $1 million in 2011 for this claim based on its share of a settlement offer to resolve the claim.

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

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing Navajo, San Juan, and Four Corners. TEP's share of reclamation costs at all three mines is expected to be $44 million upon expiration of the coal supply agreements, which expire between 2017 and 2031. The reclamation liability (present value of future liability) recorded was $18 million at December 31, 2013 and $16 million at December 31, 2012.

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

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

Discontinued Transmission Project

TEP and UNS Electric had initiated a project to jointly construct a 60-mile transmission line from Tucson, Arizona to Nogales, Arizona in response to an order by the ACC to UNS Electric to improve the reliability of electric service in Nogales. TEP and UNS Electric will not proceed with the project based on the cost of the proposed 345-kV line, the difficulty in reaching agreement with the Forest Service on a path for the line, and concurrence by the ACC of recent transmission plans filed by TEP and UNS Electric supporting elimination of this project. As part of the 2013 TEP Rate Order, TEP agreed to seek recovery of the project costs from FERC before seeking rate recovery from the ACC. See Note 3. In 2012, TEP wrote off $5 million of the capitalized costs believed not probable of recovery and recorded a regulatory asset of $5 million for the balance deemed probable of recovery.

Performance Guarantees

The participants in each of the remote generating stations in which TEP participates, including TEP, have guaranteed certain performance obligations of the other participants. Specifically, in the event of payment default of a participant, the non-defaulting participants have agreed to bear a proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generating capacity of the defaulting participants. TEP's joint participation agreements expire in 2016 through 2046.

UNS ELECTRIC CONTINGENCIES

Potential Purchase of Gas-Fired Generation Facility

In 2013, TEP and UNS Electric entered into an agreement to purchase a gas-fired generation facility. See Note 8.

ENVIRONMENTAL MATTERS

Environmental Regulation

The Environmental Protection Agency (EPA) limits the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx), particulate matter, mercury and other emissions released into the atmosphere by power plants. TEP capitalized $5 million in 2013, $2 million in 2012, and $8 million in 2011 in construction costs to comply with environmental requirements. TEP expects to capitalize environmental compliance costs of $12 million in 2014 and $36 million in 2015. In addition, TEP recorded O&M expenses of $8 million in 2013, $15 million in 2012, and $12 million in 2011. TEP expects environmental O&M expenses to be $5 million in each of 2014 and 2015.

TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its ratepayers.

Hazardous Air Pollutant Requirements

In February 2012, the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from power plants. Based on the EPA's final Mercury and Air Toxics (MATs) rule, additional emission control equipment will be required by 2015. The estimated costs include:

Estimated Emissions Control Costs:	Navajo	Four Corners	Springerville
	Millions of Dollars		
Capital Expenditures - Mercury Emissions Control	$1	$1	$5
Annual O&M Expenses	1	1	3

TEP expects Sundt and San Juan's current emission controls to be adequate to comply with the EPA's final standards.

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 rules call for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on the Navajo Indian Reservation, they are not subject to state oversight; the EPA oversees regional haze planning for these power plants.

In the western U.S., Regional Haze BART determinations have focused on controls for NOx, often resulting in a requirement to install SCRs. Complying with the EPA’s BART rules, and with other future environmental rules, may make it economically impractical to continue operating the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. TEP cannot predict the ultimate outcome of these matters.

TEP's estimated potential costs involved in meeting these rules are:

Estimated Potential Emissions Control Costs:	Navajo (1)	San Juan (2)	Four Corners (3)	Sundt (4)
	Millions of Dollars			
Capital - SCR	$42	$ 180-200	$35	$—
Capital - SNCR	—	35	—	12
Annual O&M - SCR	1	6	2	—
Annual O&M - SNCR	—	1	—	5-6

(1) The EPA is considering a better-than-BART plan wherein: one unit at Navajo will be shut down by 2020; SCR installation (or the equivalent) will be installed on the remaining two units by 2030; and conventional coal-fired generation will cease by December 2044. TEP expects the EPA to reach a decision in 2014. In addition, the installation of SCR technology could increase particulates which may require that baghouses be installed. The additional capital cost of baghouses approximates $43 million with O&M on the baghouses expected to be less than $1 million per year.

(2) The Federal Implementation Plan (FIP) requires SCR; as part of a proposal for an alternative, PNM, the State of New Mexico, and the EPA signed a non-binding agreement in which PNM agreed to close Units 2 & 3 by December 31, 2017 and install SNCRs on Units 1 & 4 by January 2016 or later. The State of New Mexico has submitted this plan to the EPA for approval. TEP expects the EPA will reach a decision in 2014. TEP owns 50% of San Juan Unit 2. At December 31, 2013, the net book value of TEP's share in San Juan Unit 2 was $113 million. If Unit 2 is retired early, we expect to request ACC approval to recover, over a reasonable time period, all costs associated with the early closure of the unit.

(3) On December 30, 2013, APS, on behalf of the co-owners of Four Corners, notified the EPA that they have chosen the alternative BART compliance strategy; APS closed Units 1, 2, and 3 in December 2013 and has agreed to the installation of SCR on Units 4 & 5 by July 31, 2018. TEP owns 7% of Four Corners Units 4 and 5.

(4) In January 2014, the EPA issued a proposal that would require TEP to either (i) install SNCR by mid-2017 or (ii) eliminate the use of coal by the end of 2017 as a better-than-BART alternative. Under the proposal, TEP would be required to notify the EPA of its decision by July 31, 2015. The EPA is expected to issue a final BART determination by July 2014. At December 31, 2013, the net book value of the Sundt coal handling facilities was $27 million. If the coal handling facilities are retired early, we expect to request ACC approval to recover, over a reasonable time period, all the remaining costs of the coal handling facilities.

BART provisions of Regional Haze Rules requiring emission control upgrades do not apply to Springerville because the plant was built after the BART-applicable dates.

NOTE 8. POTENTIAL PURCHASE OF GAS-FIRED GENERATION FACILITY

On December 23, 2013, TEP and UNS Electric entered into a purchase agreement with a subsidiary of Entegra to purchase Gila River Generating Station Unit 3 for $219 million, subject to certain closing adjustments. Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 MW, is located in Gila Bend, Arizona. TEP expects to purchase a 75% undivided interest in Gila River Unit 3 (413 MW) for approximately $164 million, and UNS Electric expects to purchase the remaining 25% undivided interest (137 MW) for approximately $55 million. TEP and UNS Electric expect the transaction to close in December 2014, subject to regulatory approvals and other closing conditions. In December 2013, UNS Electric filed an application for an accounting order with the ACC requesting authorization for UNS Electric to defer for future recovery specific non-fuel operating costs associated with Gila River Unit 3.

TEP expects to provide a letter of credit in March 2014 for $15 million to satisfy a condition of the purchase agreement. The seller of Gila River Unit 3 would be entitled to draw upon the letter of credit and apply such amount as liquidated damages if it has validly terminated the Purchase Agreement as a result of misrepresentations by TEP and UNS Electric or the failure of TEP and UNS Electric to close the transaction when the closing conditions have been satisfied. Upon the close of the transaction, the letter of credit would be canceled.

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NOTE 9. 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:

	UNS Energy			TEP		
	Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
	Millions of Dollars					
Federal Income Tax Expense at Statutory Rate	$65	$51	$62	$52	$37	$48
State Income Tax Expense, Net of Federal Deduction	8	7	8	7	5	6
Federal/State Tax Credits	(2)	(1)	(3)	(2)	(1)	(2)
Allowance for Equity Funds Used During Construction	(2)	(1)	(1)	(1)	(1)	(1)
Deferred Tax Asset Valuation Allowance	—	—	—	2	—	—
Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset	(11)	—	—	(11)	—	—
Other	—	—	1	1	(1)	1
Total Federal and State Income Tax Expense	$58	$56	$67	$48	$39	$52

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 asset and the book basis under GAAP was recorded as a deferred tax liability with an offsetting charge to income tax expense in the year the qualifying asset was placed in service. In June 2013, we recorded a regulatory asset and corresponding reduction of income tax expense of $11 million to recover previously recorded income tax expense through future rates as a result of the 2013 TEP Rate Order. The regulatory asset will be amortized as income tax expense as the qualifying assets are depreciated.

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

	UNS Energy			TEP		
	Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
	Millions of Dollars					
Current Tax Expense (Benefit):						
Federal	$(11)	$(2)	$(7)	$(8)	$(4)	$(5)
State	(2)	(2)	(2)	(2)	(2)	(2)
Total Current Tax Expense (Benefit)	(13)	(4)	(9)	(10)	(6)	(7)
Deferred Tax Expense (Benefit):						
Federal	61	51	64	47	38	50
Federal Investment Tax Credits	(1)	—	(1)	(1)	—	(1)
State	11	9	13	12	7	10
Total Deferred Tax Expense (Benefit)	71	60	76	58	45	59
Total Federal and State Income Tax Expense	$58	$56	$67	$48	$39	$52

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

	UNS Energy		TEP	
	December 31,		December 31,	
	2013	2012	2013	2012
	Millions of Dollars			
Gross Deferred Income Tax Assets:				
Capital Lease Obligations	$127	$141	$127	$141
Net Operating Loss Carryforwards	94	72	104	85
Customer Advances and Contributions in Aid of Construction	33	34	19	19
Alternative Minimum Tax Credit	43	43	24	24
Accrued Postretirement Benefits	23	23	23	23
Renewable Energy Credit Up-Front Incentive Payments	—	26	—	20
Emission Allowance Inventory	10	10	10	10
Unregulated Investment Losses	7	9	—	—
Other	50	44	44	43
Total Gross Deferred Income Tax Assets	387	402	351	365
Deferred Tax Assets Valuation Allowance	(7)	(7)	(2)	—
Gross Deferred Income Tax Liabilities:				