PINNACLE WEST CAPITAL CORP
Form 10-K
February 21, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

OR

o **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	Registrants; State of Incorporation; Addresses; and Telephone Number	IRS Employer Identification No.
1-8962	**PINNACLE WEST CAPITAL CORPORATION** (An Arizona corporation)	86-0512431

400 North Fifth Street, P.O. Box 53999

Phoenix, Arizona 85072-3999

(602) 250-1000

1-4473 **ARIZONA PUBLIC SERVICE COMPANY** **86-0011170**

(An Arizona corporation)

400 North Fifth Street, P.O. Box 53999

Phoenix, Arizona 85072-3999

(602) 250-1000

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

	Title Of Each Class	**Name Of Each Exchange On Which Registered**
PINNACLE WEST CAPITAL CORPORATION	Common Stock, No Par Value	New York Stock Exchange
ARIZONA PUBLIC SERVICE COMPANY	None	None

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

ARIZONA PUBLIC SERVICE COMPANY Common Stock, Par Value $2.50 per share

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

PINNACLE WEST CAPITAL CORPORATION	Yes x No o
ARIZONA PUBLIC SERVICE COMPANY	Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

PINNACLE WEST CAPITAL CORPORATION	Yes o No x
ARIZONA PUBLIC SERVICE COMPANY	Yes o No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PINNACLE WEST CAPITAL CORPORATION	Yes x No o
ARIZONA PUBLIC SERVICE COMPANY	Yes x No o

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).

PINNACLE WEST CAPITAL CORPORATION	Yes x No o
ARIZONA PUBLIC SERVICE COMPANY	Yes x No o

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 registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or in any amendment to this Form 10-K.x

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

PINNACLE WEST CAPITAL CORPORATION

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

ARIZONA PUBLIC SERVICE COMPANY

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of each registrant s most recently completed second fiscal quarter:

PINNACLE WEST CAPITAL CORPORATION	$6,078,967,225 as of June 30, 2013
ARIZONA PUBLIC SERVICE COMPANY	$0 as of June 30, 2013

The number of shares outstanding of each registrant s common stock as of February 14, 2014

PINNACLE WEST CAPITAL CORPORATION	110,194,366 shares
ARIZONA PUBLIC SERVICE COMPANY	Common Stock, $2.50 par value, 71,264,947 shares. Pinnacle West Capital Corporation is the sole holder of Arizona Public Service Company s Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Pinnacle West Capital Corporation s definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 21, 2014 are incorporated by reference into Part III hereof.

Arizona Public Service Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

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This combined Form 10-K is separately filed by Pinnacle West and APS. Each registrant is filing on its own behalf all of the information contained in this Form 10-K that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is filing any information that does not relate to such registrant, and therefore makes no representation as to any such information. The information required with respect to each company is set forth within the applicable items. Item 8 of this report includes Consolidated Financial Statements of Pinnacle West and Consolidated Financial Statements of APS. Item 8 also includes Notes to Pinnacle West s Consolidated Financial Statements, the majority of which also relates to APS, and Supplemental Notes, which only relate to APS s Consolidated Financial Statements.

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GLOSSARY OF NAMES AND TECHNICAL TERMS

AC	Alternating Current
ACC	Arizona Corporation Commission
ADEQ	Arizona Department of Environmental Quality
AFUDC	Allowance for Funds Used During Construction
ANPP	Arizona Nuclear Power Project, also known as Palo Verde
APS	Arizona Public Service Company, a subsidiary of the Company
APSES	APS Energy Services Company, Inc., a subsidiary of the Company sold on August 19, 2011
Base Fuel Rate	The portion of APS s retail base rates attributable to fuel and purchased power costs
BHP Billiton	BHP Billiton New Mexico Coal, Inc.
BNCC	BHP Navajo Coal Company
Cholla	Cholla Power Plant
DC	Direct Current
DOE	United States Department of Energy
DOI	United States Department of the Interior
DSMAC	Demand side management adjustment charge
El Dorado	El Dorado Investment Company, a subsidiary of the Company
El Paso	El Paso Electric Company
EPA	United States Environmental Protection Agency
FERC	United States Federal Energy Regulatory Commission
Four Corners	Four Corners Power Plant
GWh	Gigawatt-hour, one billion watts per hour
kV	Kilovolt, one thousand volts
kWh	Kilowatt-hour, one thousand watts per hour
LFCR	Lost Fixed Cost Recovery Mechanism
MMBtu	One million British Thermal Units
MW	Megawatt, one million watts
MWh	Megawatt-hour, one million watts per hour
Native Load	Retail and wholesale sales supplied under traditional cost-based rate regulation
Navajo Plant	Navajo Generating Station
NRC	United States Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company, LLC
OCI	Other comprehensive income
Palo Verde	Palo Verde Nuclear Generating Station or PVNGS
Pinnacle West	Pinnacle West Capital Corporation (any use of the words Company, we, and our refer to Pinnacle West)
PSA	Power supply adjustor approved by the ACC to provide for recovery or refund of variations in actual fuel and purchased power costs compared with the Base Fuel Rate
RES	Arizona Renewable Energy Standard and Tariff
Salt River Project or SRP	Salt River Project Agricultural Improvement and Power District
SCE	Southern California Edison Company
SunCor	SunCor Development Company
TCA	Transmission cost adjustor
VIE	Variable interest entity
West Phoenix	West Phoenix Power Plant

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FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as estimate, predict, may, believe, plan, expect, require, intend, assume and similar words. Because actual results ma materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Item 1A and in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, these factors include, but are not limited to:

- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation or regulation, including those relating to environmental requirements, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on debt and equity capital;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, particularly in real estate markets;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental and other concerns surrounding coal-fired generation;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;

- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations;
- technological developments affecting the electric industry; and
- restrictions on dividends or other provisions in our credit agreements and ACC orders.

These and other factors are discussed in the Risk Factors described in Item 1A of this report, which readers should review carefully before placing any reliance on our financial statements or disclosures. Neither Pinnacle West nor APS assumes any obligation to update these statements, even if our internal estimates change, except as required by law.

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PART I

ITEM 1. BUSINESS

Pinnacle West

Pinnacle West is a holding company that conducts business through its subsidiaries. We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the State of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona.

Pinnacle West s other operating subsidiary is El Dorado. Additional information related to this business is provided later in this report.

Our reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities, and includes electricity generation, transmission and distribution.

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

APS currently provides electric service to approximately 1.2 million customers. We own or lease 6,394 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2013, no single purchaser or user of energy accounted for more than 1.1% of our electric revenues.

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The following map shows APS s retail service territory, including the locations of its generating facilities and principal transmission lines.

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Energy Sources and Resource Planning

To serve its customers, APS obtains power through its various generation stations and through purchased power agreements. Resource planning is an important function necessary to meet Arizona s future energy needs. APS s sources of energy by type during 2013 were as follows:

Generation Facilities

APS has ownership interests in or leases the coal, nuclear, gas, oil and solar generating facilities described below. For additional information regarding these facilities, see Item 2.

Coal-Fueled Generating Facilities

Four Corners Four Corners is a 5-unit coal-fired power plant located in the northwestern corner of New Mexico. APS operates the plant and owns 100% of Four Corners Units 1, 2 and 3 and 63% of Four Corners Units 4 and 5 following the acquisition of SCE s interest in Units 4 and 5 described below. As of December 30, 2013, APS retired Units 1, 2 and 3. APS has a total entitlement from Four Corners of 970 MW.

On November 8, 2010, APS and SCE entered into an asset purchase agreement (the Asset Purchase Agreement) providing for the purchase by APS of SCE s 48% interest in each of Units 4 and 5 of Four Corners, allowing APS to acquire 739 MW from SCE. On December 30, 2013, APS and SCE closed this transaction. The final purchase price for SCE s interest was approximately $182 million, subject to certain minor post-closing adjustments.

In connection with APS s most recent retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 30, 2013, APS filed an application with the ACC to request rate adjustments prior to its next general rate case related to APS s acquisition of SCE s interest in Four Corners. If approved, these would result in an average bill impact to residential customers of approximately 2%. APS cannot predict the outcome of this request.

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Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton will be retained by NTEC under contract as the mine manager and operator until July 2016. Also occurring concurrently with the closing, the Four Corners co-owners executed a long-term agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031 (the 2016 Coal Supply Agreement). El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has agreed to assume the 7% shortfall obligation. When APS ultimately acquires a right to EPE s interest in Four Corners, by agreement or operation of law, NTEC will have an option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not exercise its option.

The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also requires the approval of the DOI, as does a related federal rights-of-way grant, which the Four Corners participants are pursuing. A federal environmental review is underway as part of the DOI review process. APS will also require a Prevention of Significant Deterioration (PSD) permit from EPA to install selective catalytic reduction (SCR) control technology at Four Corners, as described below under Environmental Matters EPA Environmental Regulation. APS cannot predict whether these federal approvals will be granted, and if so on a timely basis, or whether any conditions that may be attached to them will be acceptable to the Four Corners owners.

Cholla Cholla is a 4-unit coal-fired power plant located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4, and APS operates that unit for PacifiCorp. APS has a total entitlement from Cholla of 647 MW. APS purchases all of Cholla s coal requirements from a coal supplier that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. The Cholla coal contract runs through 2024. In addition, APS has a long-term coal transportation contract.

Navajo Generating Station The Navajo Plant is a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operates the plant and APS owns a 14% interest in Navajo Units 1, 2 and 3. APS has a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant s coal requirements are purchased from a supplier with long-term leases from the Navajo Nation and the Hopi Tribe. The Navajo Plant is under contract with its coal supplier through 2019, with extension rights through 2026. The Navajo Plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. The current lease expires in 2019.

These coal-fueled plants face uncertainties, including those related to existing and potential legislation and regulation, that could significantly impact their economics and operations. See Environmental Matters below and Management s Discussion and Analysis of Financial Condition and Results of Operations Overview and Capital Expenditures in Item 7 for developments impacting these coal-fueled facilities. See Note 11 for information regarding APS s coal mine reclamation obligations.

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Nuclear

Palo Verde Nuclear Generating Station Palo Verde is a 3-unit nuclear power plant located approximately 50 miles west of Phoenix, Arizona. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 and approximately 17% of Unit 2. In addition, APS leases approximately 12.1% of Unit 2, resulting in a 29.1% combined ownership and leasehold interest in that unit. APS has a total entitlement from Palo Verde of 1,146 MW.

Palo Verde Leases In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. In accordance with the VIE accounting guidance, APS consolidates the lessor trust entities for financial reporting purposes, and eliminates lease accounting for these transactions. The agreements expire at the end of 2015 and contain options to renew the leases or to purchase the property for fair market value at the end of the lease terms. APS was required to give notice to the respective lessor trusts between December 31, 2010 and December 31, 2012 if it wished to retain the leased assets (without specifying whether it would purchase the leased assets or extend the leases) or return the leased assets to the lessor trusts. On December 31, 2012, APS gave notice to the respective lessor trusts informing them it will retain the leased assets. APS must give notice to the respective lessor trusts by June 30, 2014 notifying them which of the purchase or lease renewal options it will exercise. We are currently analyzing these options. See Note 19 for additional information regarding the Palo Verde Unit 2 sale leaseback transactions.

Palo Verde Operating Licenses Operation of each of the three Palo Verde Units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986 and Unit 3 in November 1987, and issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2 and 3 to June 2045, April 2046 and November 2047, respectively.

Palo Verde Fuel Cycle The Palo Verde participants are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The fuel cycle for Palo Verde is comprised of the following stages:

- mining and milling of uranium ore to produce uranium concentrates;
- conversion of uranium concentrates to uranium hexafluoride;
- enrichment of uranium hexafluoride;
- fabrication of fuel assemblies;
- utilization of fuel assemblies in reactors; and
- storage and disposal of spent nuclear fuel.

The Palo Verde participants have contracted for 100% of Palo Verde s requirements for uranium concentrates through 2017, 90% of its requirements in 2018 and 45% of its requirements in 2019-2020. The participants have also contracted for all of Palo Verde s conversion services through 2016, 95% of its requirements in 2017-2018 and 45% of its requirements in 2019-2020; all of Palo Verde s enrichment services through 2020; and all of Palo Verde s fuel assembly fabrication services through 2016.

Spent Nuclear Fuel and Waste Disposal The Nuclear Waste Policy Act of 1982 (NWPA) required the DOE to accept, transport, and dispose of spent nuclear fuel and high level waste generated

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by the nation s nuclear power plants by 1998. The DOE s obligations are reflected in a contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (the Standard Contract) with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. APS is directly and indirectly involved in several legal proceedings related to DOE s failure to meet its statutory and contractual obligations regarding acceptance of spent nuclear fuel and high level waste.

APS Lawsuit for Breach of Standard Contract In December 2003, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a lawsuit against DOE in the U.S. Court of Federal Claims for damages incurred due to DOE s breach of the Standard Contract. The Court of Federal Claims ruled in favor of APS and the Palo Verde participants in October 2010 and awarded $30.2 million in damages to APS and the Palo Verde participants for costs incurred through December 2006.

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE. This lawsuit seeks to recover damages incurred due to DOE s failure to accept Palo Verde s spent nuclear fuel for the period beginning January 1, 2007 through June 30, 2011. That lawsuit is presently pending in the Court of Federal Claims.

The One-Mill Fee In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged DOE s 2010 determination of the adequacy of the one tenth of a cent per kWh fee (the one-mill fee) paid by the nation s commercial nuclear power plant owners pursuant to their individual obligations under the Standard Contract. This fee is recovered by APS in its retail rates. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit) held that DOE failed to conduct a sufficient fee analysis in making the 2010 determination. The D.C. Circuit remanded the 2010 determination to the Secretary of the DOE (Secretary) with instructions to conduct a new fee adequacy determination within six months. In February 2013, upon completion of DOE s revised one-mill fee adequacy determination, the D.C. Circuit reopened the proceedings. On November 19, 2013, the D.C. Circuit ordered the Secretary to notify Congress of his intent to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators, as he is required to do pursuant to the NWPA and the D.C. Circuit s order. On January 3, 2014, the Secretary notified Congress of his intention to suspend collection of the one-mill fee, subject to Congress disapproval.

DOE s Construction Authorization Application for Yucca Mountain The DOE had planned to meet its NWPA and Standard Contract disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In June 2008, the DOE submitted its Yucca Mountain construction authorization application to the NRC, but in March 2010, the DOE filed a motion to dismiss with prejudice the Yucca Mountain construction authorization application. Several interested parties have also intervened in the NRC proceeding. Additionally, a number of interested parties filed a variety of lawsuits in different jurisdictions around the country challenging the DOE s authority to withdraw the Yucca Mountain construction authorization application and NRC s cessation of its review of the Yucca Mountain construction authorization application. The cases have been consolidated into one matter at the D.C. Circuit. In August 2013, the D.C. Circuit ordered the NRC to resume its review of the application with available appropriated funds.

Waste Confidence On June 8, 2012, the D.C. Circuit issued its decision on a challenge by several states and environmental groups of the NRC s rulemaking regarding temporary storage and

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permanent disposal of high level nuclear waste and spent nuclear fuel. The petitioners had challenged the NRC s 2010 update to the agency s Waste Confidence Decision and temporary storage rule (Waste Confidence Decision).

The D.C. Circuit found that the agency s 2010 Waste Confidence Decision update constituted a major federal action, which, consistent with the National Environmental Policy Act (NEPA), requires either an environmental impact statement or a finding of no significant impact from the agency s actions. The D.C. Circuit found that the NRC s evaluation of the environmental risks from spent nuclear fuel was deficient, and therefore remanded the 2010 Waste Confidence Decision update for further action consistent with NEPA.

On September 6, 2012, the NRC Commissioners issued a directive to the NRC staff to proceed directly with development of a generic environmental impact statement to support an updated Waste Confidence Decision. The NRC Commissioners also directed the staff to establish a schedule to publish a final rule and environmental impact study within 24 months of September 6, 2012. In September 2013, the NRC issued its draft environmental impact statement to support an updated Waste Confidence Decision. In October 2013, the NRC began a series of nationwide public meetings to receive stakeholder input on the draft environmental impact statement. The NRC s meeting schedule was completed in December 2013. The NRC Commissioners have instructed the staff to issue the final generic environmental impact statement and rule by no later than September 2014. Untimely resolution by the NRC of the remand from the D.C. Circuit could have an adverse impact on certain NRC licensing actions. Currently, Palo Verde does not have any licensing actions pending with the NRC.

Palo Verde has sufficient capacity at its on-site independent spent fuel storage installation (ISFSI) to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, Palo Verde has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in November 2047. If uncertainties regarding the United States government s obligation to accept and store spent fuel are not favorably resolved, APS will evaluate alternative storage solutions that may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the period of extended operation.

Nuclear Decommissioning Costs APS currently relies on an external sinking fund mechanism to meet the NRC financial assurance requirements for decommissioning its interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in APS s ACC jurisdictional rates. Decommissioning costs are recoverable through a non-bypassable system benefits charge (paid by all retail customers taking service from the APS system). See Note 20 for additional information about APS s nuclear decommissioning trusts.

Palo Verde Liability and Insurance Matters See Palo Verde Nuclear Generating Station Nuclear Insurance in Note 11 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

Impact of Earthquake and Tsunami in Japan on Nuclear Energy Industry On March 11, 2011, an earthquake measuring 9.0 on the Richter Scale occurred off the coast of Japan causing a series of seven tsunamis. As a result, the Fukushima Daiichi Nuclear Power Station experienced damage.

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Following the earthquake and tsunamis, the NRC established a task force to conduct a systematic and methodical review of NRC processes and regulations to determine whether the agency should make additional improvements to its regulatory system. On March 12, 2012, the NRC issued the first regulatory requirements based on the recommendations of the Near Term Task Force. With respect to Palo Verde, the NRC issued two orders requiring safety enhancements regarding: (1) mitigation strategies to respond to extreme natural events resulting in the loss of power at plants; and (2) enhancement of spent fuel pool instrumentation.

The NRC has issued a series of interim staff guidance documents regarding implementation of these requirements. Due to the developing nature of these requirements, we cannot predict the ultimate financial or operational impacts on Palo Verde or APS; however, the NRC has directed nuclear power plants to implement the first tier recommendations of the NRC s Near Term Task Force. In response to these recommendations, Palo Verde expects to spend approximately $100 million for capital enhancements to the plant over the next several years (APS s share is 29.1%).

Natural Gas and Oil Fueled Generating Facilities

APS has six natural gas power plants located throughout Arizona, consisting of Redhawk, located near Palo Verde; Ocotillo, located in Tempe (discussed below); Sundance, located in Coolidge; West Phoenix, located in southwest Phoenix; Saguaro, located north of Tucson; and Yucca, located near Yuma. Several of the units at Yucca run on either gas or oil. APS has one oil-only power plant, Douglas, located in the town of Douglas, Arizona. APS owns and operates each of these plants with the exception of one oil-only combustion turbine unit and one oil and gas steam unit at Yucca that are operated by APS and owned by the Imperial Irrigation District. APS has a total entitlement from these plants of 3,179 MW. Gas for these plants is financially hedged up to three years in advance of purchasing and the gas is generally purchased one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2024. Fuel oil is acquired under short-term purchases delivered primarily to West Phoenix, where it is distributed to APS s other oil power plants by truck.

Ocotillo is a 330 MW 4-unit gas plant. In early 2014, APS announced a roughly $600-$700 million project to modernize the plant, which will involve retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this will increase the capacity of the site by 290 MW, to 620 MW, with completion targeted for summer 2018.

Solar Facilities

To date, APS has begun operation of 118 MW of utility scale solar through its AZ Sun Program, discussed below. These facilities are owned by APS and are located in multiple locations throughout Arizona.

Additionally, APS owns and operates more than forty small solar systems around the state. Together they have the capacity to produce approximately 4 MW of renewable energy. This fleet of solar systems includes a 3 MW facility located at the Prescott Airport and 1 MW of small solar in various locations across Arizona. APS has also developed solar photovoltaic distributed energy systems installed as part of the Community Power Project in Flagstaff, Arizona. The Community Power Project, approved by the ACC on April 1, 2010, is a pilot program through which APS owns, operates and receives energy from approximately 1 MW of solar photovoltaic distributed energy systems located within a certain test area in Flagstaff, Arizona. Additionally, APS owns 14 MW of

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solar photovoltaic systems installed across Arizona through the ACC-approved Schools and Government Program.

Purchased Power Contracts

In addition to its own available generating capacity, APS purchases electricity under various arrangements, including long-term contracts and purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements. A portion of APS s purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. (See Note 17.) APS continually assesses its need for additional capacity resources to assure system reliability.

Purchased Power Capacity APS s purchased power capacity under long-term contracts, including its renewable energy portfolio, is summarized in the table below. All capacity values are based on net capacity unless otherwise noted.

Type	Dates Available	Capacity (MW)
Purchase Agreement (a)	Year-round through December 2014	90
Purchase Agreement (b)	Year-round through June 14, 2020	60
Exchange Agreement (c)	May 15 to September 15 annually through 2020	480
Tolling Agreement	Year-round through May 2017	514
Tolling Agreement	Summer seasons through October 2019	560
Day-Ahead Call Option Agreement	Summer seasons through September 2015	500
Day-Ahead Call Option Agreement	Summer seasons through summer 2016	150
Demand Response Agreement (d)	Summer seasons through 2024	25
Renewable Energy (e)	Various	629

(a) The capacity under this agreement varies by month, with a maximum capacity of 90 MW in each of 2013 and 2014.

(b) Up to 60 MW of capacity is available; however, the amount of electricity available to APS under this agreement is based in large part on customer demand and is adjusted annually.

(c) This is a seasonal capacity exchange agreement under which APS receives electricity during the summer peak season (from May 15 to September 15) and APS returns a like amount of electricity during the winter season (from October 15 to February 15).

(d) The capacity under this agreement may be increased in 5 MW increments in each of 2014, 2015 and 2016 and 10 MW increments in years 2017 through 2024, up to a maximum of 50 MW.

(e) Renewable energy purchased power agreements are described in detail below under Current and Future Resources Renewable Energy Standard Renewable Energy Portfolio.

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Current and Future Resources

Current Demand and Reserve Margin

Electric power demand is generally seasonal. In Arizona, demand for power peaks during the hot summer months. APS s 2013 peak one-hour demand on its electric system was recorded on July 8, 2013 at 6,927 MW, compared to the 2012 peak of 7,207 MW recorded on August 8, 2012. APS s reserve margin at the time of the 2013 peak demand, calculated using system load serving capacity, was 27%. Excluding certain contractual rights to call on additional capacity on short notice, which APS may use in the event of unusual weather or unplanned outages, the 2013 reserve margin was 17%. APS anticipates the reserve margin for 2014 will be approximately 34% or 24% excluding contractual rights to call on additional capacity. APS expects that our reserve margins will decrease over the next three years and that additional conventional resources will be needed around 2017.

Future Resources and Resource Plan

Under the ACC s resource planning rule, APS will file by April 1 of each even year its resource plans for the next fifteen-year period. The rule requires the ACC to issue an order with its acknowledgment of APS s resource plan within approximately ten months following its submittal. The ACC s acknowledgment of APS s resource plan will consider factors such as the total cost of electric energy services, demand management, analysis of supply-side options, system reliability and risk management. APS will be filing its next resource plan by April 1, 2014.

Renewable Energy Standard

In 2006, the ACC adopted the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. The renewable energy requirement is 4.5% of retail electric sales in 2014 and increases annually until it reaches 15% in 2025. In APS s 2009 retail rate case settlement agreement (the 2009 Settlement Agreement), APS committed to have 1,700 GWh of new renewable resources in service by year-end 2015 in addition to its 2008 renewable resource commitments. Taken together, APS s commitment is estimated to be approximately 12% of retail sales, by year-end 2015, which is more than double the RES target of 5% for that year. A component of the RES is focused on stimulating development of distributed energy systems (generally speaking, small-scale renewable technologies that are located on customers properties, such as rooftop solar systems). Accordingly, under the RES, an increasing percentage of that requirement must be supplied from distributed energy resources. This distributed energy requirement is 30% of the overall RES requirement of 4.5% in 2014. The following table summarizes the RES requirement standard (not including the additional commitment required by the 2009 Settlement Agreement) and its timing:

	2014	2015	2020	2025
RES as a % of retail electric sales	4.5%	5%	10%	15%
Percent of RES to be supplied from distributed energy resources	30%	30%	30%	30%

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Renewable Energy Portfolio. To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1175 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1074 MW are currently in operation and 101 MW are under contract for development or are under construction. Renewable resources in operation include 137 MW of facilities owned by APS, 629 MW of long-term purchased power agreements, and an estimated 308 MW of customer-sited, third-party owned distributed energy resources.

APS s strategy to achieve its RES requirements includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS. APS is developing owned solar resources through the AZ Sun Program. Under this program to date, APS estimates its investment commitment will be approximately $695 million. See Note 3 for additional details about the AZ Sun Program, including the related cost recovery.

The following table summarizes APS s renewable energy sources currently in operation and under development. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid.

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	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity In Operation (MW AC)	Net Capacity Planned/Under Development (MW AC)
APS Owned					
Solar:					
AZ Sun Program:					
Paloma	**Gila Bend, AZ**	**2011**		**17**	
Cotton Center	**Gila Bend, AZ**	**2011**		**17**	
Hyder Phase 1	**Hyder, AZ**	**2011**		**11**	
Hyder Phase 2	**Hyder, AZ**	**2012**		**5**	
Chino Valley	**Chino Valley, AZ**	**2012**		**19**	
Hyder II	**Hyder, AZ**	**2013**		**14**	
Foothills	**Yuma, AZ**	**2013**		**35**	
Gila Bend	**Gila Bend, AZ**	**2014**			**32**
Subtotal AZ Sun Program (a)				**118**	**32**
Multiple Facilities	**AZ**	**Various**		**4**	
Distributed Energy:					
APS Owned (b)	**AZ**	**Various**		**15**	
Total APS Owned				**137**	**32**
Purchased Power Agreements					
Solar:					
Solana	**Gila Bend, AZ**	**2013**	**30**	**250**	
RE Ajo	**Ajo, AZ**	**2011**	**25**	**5**	
Sun E AZ 1	**Prescott, AZ**	**2011**	**30**	**10**	
Saddle Mountain	**Tonopah, AZ**	**2012**	**30**	**15**	
Badger	**Tonopah, AZ**	**2013**	**30**	**15**	
Gillespie	**Maricopa County, AZ**	**2013**	**30**	**15**	
Wind:					
Aragonne Mesa	**Santa Rosa, NM**	**2006**	**20**	**90**	
High Lonesome	**Mountainair, NM**	**2009**	**30**	**100**	
Perrin Ranch Wind	**Williams, AZ**	**2012**	**25**	**99**	
Geothermal:					
Salton Sea	**Imperial County, CA**	**2006**	**23**	**10**	
Biomass:					
Snowflake	**Snowflake, AZ**	**2008**	**15**	**14**	
Biogas:					
Glendale Landfill	**Glendale, AZ**	**2010**	**20**	**3**	
NW Regional Landfill	**Surprise, AZ**	**2012**	**20**	**3**	
Total Purchased Power Agreements				**629**	**0**
Distributed Energy					
Solar (c)					
Third-party Owned	**AZ**	**Various**		**275**	**69**
Agreement 1	**Bagdad, AZ**	**2011**	**25**	**15**	
Agreement 2	**AZ**	**2011-2012**	**20-21**	**18**	
Total Distributed Energy				**308**	**69**
Total Renewable Portfolio				**1074**	**101**

(a) Under the AZ Sun Program, an additional 20 MW has been approved to be contracted, but is not included in the table above since it is not yet under contract. Another 30 MW is possible under AZ Sun, but has not yet been approved.

(b) Includes Flagstaff Community Power Project and APS School and Government Program.

(c) Distributed generation is produced in DC and is converted to AC for reporting purposes.

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Demand Side Management

In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated its Energy Efficiency rulemaking, with a proposed Energy Efficiency Standard (EES) of 22% cumulative annual energy savings by 2020. This standard was adopted and became effective on January 1, 2011. This ambitious standard will likely impact Arizona s future energy resource needs. (See Note 3 for energy efficiency and other demand side management obligations resulting from the 2009 Settlement Agreement).

Government Awards

Through the American Recovery and Reinvestment Act of 2009 (ARRA) and other DOE initiatives, the Federal government made a number of programs available for utilities to develop renewable resources, improve reliability and create jobs. APS continues its work on a $3 million non-ARRA award for a high penetration photovoltaic generation study related to the Community Power Project in Flagstaff, Arizona. This award will conclude during 2015 and is contingent upon APS meeting certain project milestones, including DOE-established budget parameters.

Competitive Environment and Regulatory Oversight

Retail

The ACC regulates APS s retail electric rates and its issuance of securities. The ACC must also approve any significant transfer or encumbrance of APS s property used to provide retail electric service and approve or receive prior notification of certain transactions between Pinnacle West, APS and their respective affiliates.

APS is subject to varying degrees of competition from other investor-owned electric and gas utilities in Arizona (such as Southwest Gas Corporation), as well as cooperatives, municipalities, electrical districts and similar types of governmental or non-profit organizations. In addition, some customers, particularly industrial and large commercial customers, may own and operate generation facilities to meet some or all of their own energy requirements. This practice is becoming more popular with customers installing or having installed products such as rooftop solar panels to meet or supplement their energy needs.

On April 14, 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not public service corporations under the Arizona Constitution, and are therefore not regulated by the ACC. A second matter is pending with the ACC to determine whether that ruling should extend to solar providers who serve a broader customer base under the same business model. Use of such products by customers within our territory would result in an increasing level of competition. APS cannot predict when, and the extent to which, additional electric service providers will enter or re-enter APS s service territory.

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. As a result, as of January 1, 2001, all of APS s retail customers were eligible to choose alternate energy suppliers. Although some very limited retail competition existed in APS s service territory in

1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS s customers. In 2000, the Arizona Superior Court found that the rules were in part unconstitutional and in other respects unlawful, the latter finding being primarily on procedural grounds, and invalidated all ACC orders authorizing competitive electric services providers to operate in Arizona. In 2004, the Arizona Court of Appeals invalidated some, but not all of the rules and upheld the invalidation of the orders authorizing competitive electric service providers. In 2005, the Arizona Supreme Court declined to review the Court of Appeals decision.

In 2008, the ACC directed the ACC staff to investigate whether such retail competition was in the public interest and what legal impediments remain to competition in light of the Court of Appeals decision referenced above. The ACC staff s report on the results of its investigation was issued on August 12, 2010. The report stated that additional analysis, discussion and study of all aspects of the issue are required in order to perform a proper evaluation. While the report did not make any specific recommendations other than to conduct more workshops, the report did state that the current retail electric competition rules are incomplete and in need of modification.

On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a market basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. The ACC opened a new docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. Workshops in this docket are expected to be held in 2014.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS s transmission rates.) During 2013, approximately 5.4% of APS s electric operating revenues resulted from such sales and services. APS s wholesale activity primarily consists of managing fuel and purchased power supplies to serve retail customer energy requirements. APS also sells, in the wholesale market, its generation output that is not needed for APS s Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. Additionally, subject to specified parameters, APS hedges both electricity and fuels. The majority of these activities are undertaken to mitigate risk in APS s portfolio.

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Environmental Matters

Climate Change

Legislative Initiatives. There have been no recent attempts by Congress to pass legislation that would regulate greenhouse gas (GHG) emissions, and it is unclear if and when the 113th Congress will consider a climate change bill. In the event climate change legislation ultimately passes, the actual economic and operational impact of such legislation on APS depends on a variety of factors, none of which can be fully known until a law is enacted and the specifics of the resulting program are established. These factors include the terms of the legislation with regard to allowed GHG emissions; the cost to reduce emissions; in the event a cap-and-trade program is established, whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned (and, if so, the cost of those allowances in the marketplace) and whether offsets and other measures to moderate the costs of compliance will be available; and, in the event of a carbon tax, the amount of the tax per pound of carbon dioxide (CO_2) equivalent emitted.

In addition to federal legislative initiatives, state-specific initiatives may also impact our business. While Arizona has no pending legislation and no proposed agency rule regulating GHGs in Arizona, the California legislature enacted AB 32 and SB 1368 in 2006 to address GHG emissions. In October 2011, the California Air Resources Board approved final regulations that established a state-wide cap on GHG emissions beginning on January 1, 2013 and established a GHG allowance trading program under that cap. The first phase of the program, which applies to, among other entities, importers of electricity, commenced on January 1, 2013. Under the program, entities selling electricity into California, including APS, must hold carbon allowances to cover GHG emissions associated with electricity sales into California from outside the state. APS is authorized to recover the cost of these carbon allowances through the PSA.

We continue to monitor Arizona regulatory activities and other state legislative developments to understand the extent to which they may affect our business, including our sales into the impacted states or the ability of our out-of-state power plant participants to continue their participation in certain coal-fired power plants. In particular, SCE, a prior participant in Four Corners, indicated that SB 1368 may prohibit it from making emission control expenditures at the plant and, as a result, SCE sold its entire 48% interest in each of Units 4 and 5 of Four Corners to APS on December 30, 2013. (See Energy Sources and Resource Planning Generation Facilities Coal-Fueled Generating Facilities Four Corners above for details of the sale of SCE s interest in Four Corners to APS.)

Regulatory Initiatives. In 2009, EPA determined that GHG emissions endanger public health and welfare. This determination was made in response to a 2007 United States Supreme Court ruling that GHGs fit within the Clean Air Act s broad definition of air pollutant and, as a result, EPA has the authority to regulate GHG emissions of new motor vehicles under the Clean Air Act. As a result of this endangerment finding, EPA determined that the Clean Air Act required new regulatory requirements for new and modified major GHG emitting sources, including power plants. EPA issued a rule under the Clean Air Act, known as the tailoring rule, establishing new GHG emissions thresholds that determine when sources, including power plants, must obtain air operating permits or New Source Review permits. New Source Review, or NSR, is a pre-construction permitting program under the Clean Air Act that requires analysis of pollution controls prior to building a new stationary source or making major modifications to an existing stationary source. The tailoring rule became applicable to power plants in January 2011. Several groups filed lawsuits challenging EPA s endangerment finding and the tailoring rule, but the D.C. Circuit upheld these rules. Petitioners asked

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the United States Supreme Court to reverse all or part of the appeals court s decision upholding EPA s GHG rules. On October 15, 2013, the Supreme Court granted these petitions limiting the question it would review to whether EPA permissibly determined that its regulation of GHG emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit such gasses, including power plants. The Court is expected to issue its decision in the case no later than mid-2014.

APS does not expect that any resulting Supreme Court decision or the tailoring rule will have a significant impact on its current operations. The rule will require APS to consider the impact of GHG emissions as part of its traditional NSR analysis for new sources and major modifications to existing plants.

On June 25, 2013, President Obama unveiled his Climate Action Plan addressing his plans to reduce GHG emissions in the United States. While the plan identifies a wide range of strategies for cutting GHG emissions, most important to APS and the electric utility industry is the implementation of carbon pollution standards for new, modified, and existing fossil-fired electric generating units. Concurrent with the President s speech, the White House issued a Presidential Memorandum directing EPA to use its existing authorities under the Clean Air Act to develop GHG emission standards for new, modified, and existing power plants. The Presidential Memorandum directs EPA to propose GHG emission standards for modified and existing units by June 1, 2014 and to finalize them by June 1, 2015. The memorandum further directed EPA to reissue proposed standards of performance for new power plants by September 20, 2013 and to finalize them in a timely fashion.

Consistent with President Obama s June 2013 directive, pursuant to its authority under the Clean Air Act and its endangerment finding, on September 20, 2013, EPA issued a proposed rule, which would establish New Source Performance Standards (NSPS) for new fossil-fired power plants. Once finalized, APS does not expect that the GHG NSPS will have any material impact on its current operations. EPA indicated in its proposal that the rule will not apply to modified or reconstructed electric generating units, which are to be addressed in a subsequent rulemaking. We cannot currently predict the shape of any final rules or standards for existing fossil-fired power plants or assess how they might potentially impact the company. APS will continue to monitor these standards as they are developed.

Company Response to Climate Change Initiatives. We have undertaken a number of initiatives to address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency. (See Energy Sources and Resource Planning Current and Future Resources above for details of these plans and initiatives.) APS currently has a diverse portfolio of renewable resources, including solar, wind, geothermal, biogas, and biomass, and we expect the percentage of renewable energy in our resource portfolio to increase over the coming years.

APS prepares an inventory of GHG emissions from its operations. This inventory is reported to EPA under the EPA GHG Reporting Program and is voluntarily communicated to the public in Pinnacle West s annual Corporate Responsibility Report, which is available on our website (*www.pinnaclewest.com*). The report provides information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle West s website, including the Corporate Responsibility Report, is not incorporated by reference into this report.

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EPA Environmental Regulation

Regional Haze Rules. In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal land, EPA) to determine what pollution control technologies constitute the Best Available Retrofit Technology (BART) for certain older major stationary sources, including fossil-fired power plants. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis.

The Four Corners and Navajo Plant participants obligations to comply with EPA s final BART determinations (and Cholla s obligations to comply with ADEQ s and EPA s determinations), coupled with the financial impact of potential 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 continue their participation in these plants.

Cholla. In 2007, ADEQ required APS to perform a BART analysis for Cholla pursuant to the Clean Air Visibility Rule. APS completed the BART analysis for Cholla and submitted its BART recommendations to ADEQ in early 2008. The recommendations include the installation of certain pollution control equipment that APS believes constitutes BART. ADEQ reviewed APS s recommendations and submitted its proposed BART State Implementation Plan (SIP) for Cholla and other sources in Arizona in early 2011.

On December 2, 2011, EPA provided notice of a proposed consent decree to address a lawsuit filed by a number of environmental non-governmental organizations, which alleged that EPA failed to promulgate Federal Implementation Plans (FIPs) for states that have not yet submitted all or part of the required regional haze SIPs. In accordance with the consent decree, on December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA approved ADEQ s BART emissions limits for sulfur dioxide (SO_2) and emissions of particulate matter (PM), but added a SO_2 removal efficiency requirement of 95%. In addition, EPA disapproved ADEQ s BART determinations for oxides of nitrogen (NO_x) and promulgated a FIP establishing a new, more stringent bubbled NO_x emission rate applicable to the two BART-eligible Cholla units owned by APS and the other BART-eligible unit owned by PacifiCorp. In order to comply with this new rate, APS will be required to install SCR control technology on all three of the Cholla units. APS s total costs for these post-combustion NO_x controls would be approximately $200 million. This amount is not included in our current estimates for environmental capital expenditures in Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Expenditures in Item 7. Under the FIP, APS has five years from December 2012 to complete installation of the equipment and achieve the BART emission limit for NO_x.

APS believes that EPA s final rule as it applies to Cholla is unsupported and that EPA had no basis for disapproving Arizona s SIP and promulgating a FIP that is inconsistent with the state s considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. We expect briefing in the case to be completed in February 2014.

Four Corners. On August 6, 2012, EPA issued its final BART determination for Four Corners. The rule included two compliance options. On December 30, 2013, APS notified EPA that the Four Corners participants selected the BART alternative, which required APS to retire Four Corners Units 1-3 by January 1, 2014 and install and operate SCR control technology on Units 4

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and 5 by July 31, 2018. Consistent with this alternative, APS retired Four Corners Units 1-3 on December 30, 2013. APS s 63% share of the costs for these controls is estimated to be approximately $350 million. Approximately half of these costs are included in the capital expenditure estimates in Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Expenditures in Item 7 because APS expects to incur that portion of the costs during the 2014 through 2016 timeframe. For PM emissions, EPA is requiring Units 4 and 5 to meet an emission limit of 0.015 lb/MMBtu and a 20% opacity limit, both of which are achievable through operation of the existing baghouses. Although unrelated to BART, the final BART rule also imposes a 20% opacity limitation on certain fugitive dust emissions from Four Corners coal and material handling operations.

On October 22, 2012, WildEarth Guardians filed a petition for review in the United States Court of Appeals for the Ninth Circuit alleging that EPA violated the Endangered Species Act (ESA) when it promulgated the final Four Corners BART FIP. The court granted APS s motion for leave to intervene as a defendant in the case. A decision is expected before the end of 2014. We cannot currently predict the outcome of this case or whether such outcome will have a material adverse impact on our financial position, results of operations, or cash flows.

Navajo Plant. On January 18, 2013, EPA issued a proposed BART rule for the Navajo Plant, which would require installation of SCR technology in order to achieve a new, more stringent plant-wide NO_x emission limit. Under the proposal, the Navajo Plant participants would have up to five years after EPA issues its final determinations to achieve compliance with the BART requirements. APS s total costs for post-combustion NO_x controls could be up to approximately $200 million. The majority of these costs are not included in the capital expenditure estimates described in Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Expenditures in Item 7 because APS expects to incur such costs in years following 2016. EPA s proposal also includes an Alternative to BART, which would provide the Navajo Plant with additional time to install the SCR technology. Under this better than BART alternative, the Navajo Plant participants would be required to install SCR technology on one unit per year in each of 2021, 2022, and 2023. In response to EPA s request for comments on other options that could set longer time frames for installing pollution controls if the Navajo Plant can achieve additional emission reductions, on July 26, 2013, a group of stakeholders, including SRP, the operating agent for the Navajo Plant, submitted to EPA two suggested alternatives to BART, which would achieve greater NO_x emission reductions than EPA s proposed BART rule. If the rule is finalized as proposed, depending on which alternate operating scenario the Navajo Plant participants ultimately select, the required NO_x emission reductions could be achieved by either closing one of the three 750 MW units at the plant or curtailing energy production across all three units, such that the emission reductions are commensurate with the closure of approximately one of the Navajo Plant units. On September 25, 2013, EPA issued a supplemental BART proposal proposing to determine that these alternatives are better than BART because NO_x emissions that would be achieved thereunder would result in greater reasonable progress toward the national visibility goal than EPA s proposed BART determination.

Mercury and other Hazardous Air Pollutants. On December 16, 2011, EPA issued the final Mercury and Air Toxics Standards (MATS), which established maximum achievable control technology (MACT) standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired power plants. Generally, plants will have three years after the effective date of the rule to achieve compliance. In the case of Cholla, APS will have a total of four years after the MATS effective date to comply with the new MACT standards, because on September 24, 2012, the permitting authority granted APS s request for a one-year compliance date extension. Similarly, SRP

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will have until April 16, 2016 to comply with MATS at the Navajo Plant, as a result of a one-year extension granted by EPA and the Navajo Nation EPA on January 27, 2014.

The MATS will require APS to install additional pollution control equipment. APS has installed certain of the equipment necessary to meet the anticipated standards. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $120 million for Cholla Units 2 and 3. These costs are not included in the capital expenditure estimates described in Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Expenditures in Item 7. No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, is still evaluating compliance options under the rules.

Cooling Water Intake Structures. EPA issued its proposed cooling water intake structures rule on April 20, 2011, which provides national standards applicable to certain cooling water intake structures at existing power plants and other facilities pursuant to Section 316(b) of the Clean Water Act. The proposed standards are intended to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). To minimize impingement mortality, the proposed rule would require facilities, such as Four Corners and the Navajo Plant, to either demonstrate that impingement mortality at their cooling water intakes does not exceed a specified rate or reduce the flow at those structures to less than a specified velocity, and to take certain protective measures with respect to impinged fish. To minimize entrainment mortality, the proposed rule would also require these facilities to conduct a structured site-specific analysis to determine what site-specific controls, if any, should be required. Additional studies and a peer review process will also be required at these facilities.

As proposed, existing facilities subject to the rule would have to comply with the impingement mortality requirements as soon as possible, but in no event later than eight years after the effective date of the rule, and would have to comply with the entrainment requirements as soon as possible under a schedule of compliance established by the permitting authority. APS is performing analyses to determine the costs of compliance with the proposed rule. EPA will issue the final standards upon completion of its ongoing ESA consultations with the U.S. Fish and Wildlife Service and National Marine Fisheries Service and is working to finalize the standards by April 2014.

Coal Combustion Waste. On June 21, 2010, EPA released its proposed regulations governing the handling and disposal of coal combustion residuals (CCRs), such as fly ash and bottom ash. APS currently disposes of CCRs in ash ponds and dry storage areas at Cholla and Four Corners, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete production. EPA proposes regulating CCRs as either non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) or hazardous waste under Subtitle C of RCRA and requested comments on three different alternatives. The hazardous waste proposal would phase out the use of ash ponds for disposal of CCRs. The other two proposals would regulate CCRs as non-hazardous waste and impose performance standards for ash disposal. One of these proposals would require retrofitting or closure of currently unlined ash ponds, while the other proposal would not require the installation of liners or pond closures. EPA has not yet indicated a preference for any of the alternatives.

In April 2012, a coalition of environmental groups filed suit to compel EPA to finalize its proposed CCR rule. Soon thereafter, coal ash recyclers filed similar lawsuits against EPA, which were consolidated with the environmental groups lawsuits. On January 29, 2014, the parties in the CCR

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deadline litigation filed a consent decree with the court obligating EPA to make a final decision by December 2014 whether or not to adopt the Subtitle D option for CCR. The consent decree does not foreclose EPA from adopting the Subtitle C option. We cannot currently predict the timing or content of EPA s final rule or whether this action will have a material adverse impact on our financial position, results of operations, or cash flows.

Effluent Limitation Guidelines. On April 19, 2013, EPA proposed revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired electric generating units. EPA s proposal offers numerous options (four of which are preferred alternatives) that target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and non-chemical metal cleaning wastes operations. The preferred alternatives differ with respect to the scope of requirements that would be applicable to existing discharges of pollutants found in wastestreams generated at existing power plants. All four alternatives would establish a zero discharge effluent limit for all pollutants in fly ash transport water. However, requirements governing bottom ash transport water differ depending on which alternative EPA ultimately chooses and could range from effluent limits based on Best Available Technology Economically Achievable to zero discharge effluent limits. Depending on which alternative EPA finalizes, Four Corners may be required to change equipment and operating practices affecting boilers and ash handling systems, as well as change its waste disposal techniques. We cannot currently predict the shape of EPA s final rule or whether this action will have a material adverse impact on our financial position, results of operations, or cash flows. EPA is currently subject to a consent decree deadline to finalize the revised guidelines by May 2014, although it is in negotiations to obtain an extension of time.

Ozone National Ambient Air Quality Standards. In March 2008, EPA adopted new, more stringent eight-hour ozone standards, known as national ambient air quality standards (NAAQS). In January 2010, EPA proposed to adopt even more stringent eight-hour ozone NAAQS. However, the following year, President Obama decided to withdraw EPA s revised ozone standards until completion of the next review. EPA had a March 2013 deadline to complete its review of the 2008 ozone NAAQS, but failed to meet it. Although EPA has not announced a timeline for its review, it may release new proposed standards in the second half of 2014. As ozone standards become more stringent, our fossil generation units may come under increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds and/or to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. At this time, APS is unable to predict the timing of the final standards or what impact the adoption of these standards may have on its financial position, results of operations, or cash flows.

New Source Review. On April 6, 2009, APS received a request from EPA under Section 114 of the Clean Air Act seeking detailed information regarding projects at and operations of Four Corners. This request is part of an enforcement initiative that EPA has undertaken under the Clean Air Act. EPA has taken the position that many utilities have made certain physical or operational changes at their plants that should have triggered additional regulatory requirements under the NSR provisions of the Clean Air Act. Other electric utilities have received and responded to similar Section 114 requests, and several of them have been the subject of notices of violation and lawsuits by EPA. APS responded to EPA s request in August 2009 and is currently unable to predict any resulting actions the EPA may take, including any potential litigation.

Clean Air Act Citizen Lawsuit. On October 4, 2011, Earthjustice, on behalf of several environmental non-governmental organizations, filed a lawsuit in the United States District Court for the District of New

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Mexico against APS and the other Four Corners participants alleging violations of the NSR provisions of the Clean Air Act. Subsequent to filing its original complaint, on January 6, 2012, Earthjustice filed an amended complaint adding claims for violations of the Clean Air Act s NSPS program. Among other things, the environmental plaintiffs seek to have the court enjoin operations at Four Corners until APS applies for and obtains any required NSR permits and complies with the NSPS. The plaintiffs further request the court to order the payment of civil penalties, including a beneficial mitigation project. On April 2, 2012, APS and the other Four Corners participants filed motions to dismiss. The case is being held in abeyance while the parties seek to negotiate a settlement. On March 30, 2013, upon joint motion of the parties, the court issued an order deeming the motions to dismiss withdrawn without prejudice during pendency of the stay. At such time as the stay is lifted, APS and the other Four Corners participants may reinstate their motions to dismiss. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Superfund-Related Matters. The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who generated, transported or disposed of hazardous substances at a contaminated site are among those who are potentially responsible parties (PRPs). PRPs may be strictly, and often are jointly and severally, liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52nd Street Superfund Site, Operable Unit 3 (OU3) in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study work plan. We estimate that our costs related to this investigation and study will be approximately $2 million. We anticipate incurring additional expenditures in the future, but because the overall investigation is not complete and ultimate remediation requirements are not yet finalized, at the present time expenditures related to this matter cannot be reasonably estimated.

On August 6, 2013, the Roosevelt Irrigation District (RID) filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID s groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS s current and former ownership of facilities in and around OU3. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Manufactured Gas Plant Sites. Certain properties which APS now owns or which were previously owned by it or its corporate predecessors were at one time sites of, or sites associated with, manufactured gas plants. APS is taking action to voluntarily remediate these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations or cash flows.

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Navajo Nation Environmental Issues

Four Corners and the Navajo Plant are located on the Navajo Reservation and are held under easements granted by the federal government, as well as leases from the Navajo Nation. See Energy Sources and Resource Planning Generation Facilities Coal-Fueled Generating Facilities above for additional information regarding these plants.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the Navajo Acts). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water, and pesticide activities, including those activities that occur at Four Corners and the Navajo Plant. On October 17, 1995, the Four Corners participants and the Navajo Plant participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, challenging the applicability of the Navajo Acts as to Four Corners and the Navajo Plant. The Court has stayed these proceedings pursuant to a request by the parties, and the parties are seeking to negotiate a settlement.

In April 2000, the Navajo Nation Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. APS believes the Navajo Nation exceeded its authority when it adopted the operating permit regulations. On July 12, 2000, the Four Corners participants and the Navajo Plant participants each filed a petition with the Navajo Supreme Court for review of these regulations. Those proceedings have been stayed, pending the settlement negotiations mentioned above. APS cannot currently predict the outcome of this matter.

On May 18, 2005, APS, Salt River Project, as the operating agent for the Navajo Plant, and the Navajo Nation executed a Voluntary Compliance Agreement to resolve their disputes regarding the Navajo Nation Air Pollution Prevention and Control Act. As a result of this agreement, APS sought, and the courts granted, dismissal of the pending litigation in the Navajo Nation Supreme Court and the Navajo Nation District Court, to the extent the claims relate to the Clean Air Act. The agreement does not address or resolve any dispute relating to other Navajo Acts. APS cannot currently predict the outcome of this matter.

Water Supply

Assured supplies of water are important for APS s generating plants. At the present time, APS has adequate water to meet its needs. However, the Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future operations of the plant. The effect of the drought cannot be fully assessed at this time, and APS cannot predict the ultimate outcome, if any, of the drought or whether the drought will adversely affect the amount of power available, or the price thereof, from Four Corners.

Conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions, which, in addition to future supply conditions, have the potential to impact APS s operations.

San Juan River Adjudication. Both groundwater and surface water in areas important to APS s operations have been the subject of inquiries, claims, and legal proceedings, which will require

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a number of years to resolve. APS is one of a number of parties in a proceeding, filed March 13, 1975, before the Eleventh Judicial District Court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss. In addition, APS is a party to a water contract that allows the company to secure water for Four Corners in the event of a water shortage and is a party to a shortage sharing agreement, which provides for the apportionment of water supplies to Four Corners in the event of a water shortage in the San Juan River Basin.

Gila River Adjudication. A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Arizona Superior Court. Palo Verde is located within the geographic area subject to the summons. APS s rights and the rights of the other Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. As operating agent of Palo Verde, APS filed claims that dispute the court s jurisdiction over the Palo Verde participants groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Several of APS s other power plants are also located within the geographic area subject to the summons. APS s claims dispute the court s jurisdiction over APS s groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court s criteria for resolving groundwater claims. Litigation on both of these issues has continued in the trial court. In December 2005, APS and other parties filed a petition with the Arizona Supreme Court requesting interlocutory review of a September 2005 trial court order regarding procedures for determining whether groundwater pumping is affecting surface water rights. The Arizona Supreme Court denied the petition in May 2007, and the trial court is now proceeding with implementation of its 2005 order. No trial date concerning APS s water rights claims has been set in this matter.

Little Colorado River Adjudication. APS has filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court, which was originally filed on September 5, 1985. APS s groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and, therefore, is potentially at issue in the case. APS s claims dispute the court s jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. Other claims have been identified as ready for litigation in motions filed with the court. No trial date concerning APS s water rights claims has been set in this matter.

Although the above matters remain subject to further evaluation, APS does not expect that the described litigation will have a material adverse impact on its financial position, results of operations, or cash flows.

BUSINESS OF OTHER SUBSIDIARIES

Our other operating subsidiary, El Dorado, is not expected to contribute in any material way to our future financial performance, nor will it require any material amounts of capital over the next three years. We continue to focus on our core utility business and streamlining the Company.

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El Dorado

El Dorado owns minority interests in several energy-related investments and Arizona community-based ventures. El Dorado s short-term goal is to prudently realize the value of its existing investments. As of December 31, 2013, El Dorado had total assets of $15 million.

SunCor

In February 2012, our other first-tier subsidiary, SunCor, filed for protection under the United States Bankruptcy Code to complete an orderly liquidation of its business. On March 25, 2013, the bankruptcy plan submitted to the court and agreed to by SunCor and its creditors (the Joint Plan) became effective. The Joint Plan provides for the full release of Pinnacle West and its affiliates from any and all claims related to SunCor, SunCor s subsidiaries, and their respective estates. SunCor and its subsidiaries are in the process of being formally dissolved.

OTHER INFORMATION

Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. Additional information for each of these companies is provided below:

	Principal Executive Office Address	Year of Incorporation	Approximate Number of Employees at December 31, 2013
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	81
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,352
El Dorado	400 North Fifth Street Phoenix, AZ 85004	1983	
Total			6,433

The APS number includes employees at jointly-owned generating facilities (approximately 2,865 employees) for which APS serves as the generating facility manager. Approximately 1,797 APS employees are union employees. APS entered into a three-year collective bargaining agreement with union employees in the fossil generation, energy delivery and customer service business areas that expires in April 2014. The Company is currently engaged in discussions with union representatives to enter into an extension of the current agreement. In January 2013, the Palo Verde security officers voted to change their collective bargaining representative from the Security, Police and Fire Professionals of America to the United Security Professionals of America (USPA), and the National Labor Relations Board certified the results. The Company is currently engaged in negotiations with the USPA over the terms of a new collective bargaining agreement.

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WHERE TO FIND MORE INFORMATION

We use our website (*www.pinnaclewest.com)* as a channel of distribution for material Company information. The following filings are available free of charge on our website as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission (SEC): Annual Reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports. Our board and committee charters, Code of Ethics for Financial Executives, Code of Ethics and Business Practices and other corporate governance information is also available on the Pinnacle West website. Pinnacle West will post any amendments to the Code of Ethics for Financial Executives and Code of Ethics and Business Practices, and any waivers that are required to be disclosed by the rules of either the SEC or the New York Stock Exchange, on its website. The information on Pinnacle West s website is not incorporated by reference into this report.

You can request a copy of these documents, excluding exhibits, by contacting Pinnacle West at the following address: Pinnacle West Capital Corporation, Office of the Corporate Secretary, Mail Station 8602, P.O. Box 53999, Phoenix, Arizona 85072-3999 (telephone 602-250-4400).

ITEM 1A. RISK FACTORS

In addition to the factors affecting specific business operations identified in the description of these operations contained elsewhere in this report, set forth below are risks and uncertainties that could affect our financial results. Unless otherwise indicated or the context otherwise requires, the following risks and uncertainties apply to Pinnacle West and its subsidiaries, including APS.

REGULATORY RISKS

Our financial condition depends upon APS s ability to recover costs in a timely manner from customers through regulated rates and otherwise execute its business strategy.

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies that significantly influence its business, liquidity, results of operations and its ability to fully recover costs from utility customers in a timely manner. The ACC regulates APS s retail electric rates and FERC regulates rates for wholesale power sales and transmission services. The profitability of APS is affected by the rates it may charge and the timeliness of recovering costs incurred through its rates. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings and ancillary matters which may come before the ACC and FERC. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify final orders under certain circumstances. The ACC must also approve APS s issuance of securities and any transfer of APS property used to provide retail electric service, and must approve or receive prior notification of certain transactions between us, APS and our respective affiliates. Decisions made by the ACC or FERC could have a material adverse impact on our financial condition, results of operations or cash flows.

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APS s ability to conduct its business operations and avoid fines and penalties depends upon compliance with federal, state or local statutes, regulations and ACC requirements, and obtaining and maintaining certain regulatory permits, approvals and certificates.

APS must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of agencies that regulate APS s business, including FERC, NRC, EPA, the ACC and state and local governmental agencies. These agencies regulate many aspects of APS s utility operations, including safety and performance, emissions, siting and construction of facilities, customer service and the rates that APS can charge retail and wholesale customers. Failure to comply can subject APS to, among other things, fines and penalties. For example, under the Energy Policy Act of 2005, FERC can impose penalties (up to one million dollars per day per violation) for failure to comply with mandatory electric reliability standards. APS is also required to have numerous permits, approvals and certificates from these agencies. APS believes the necessary permits, approvals and certificates have been obtained for its existing operations and that APS s business is conducted in accordance with applicable laws in all material respects. However, changes in regulations or the imposition of new or revised laws or regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies.

The operation of APS s nuclear power plant exposes it to substantial regulatory oversight and potentially significant liabilities and capital expenditures.

The NRC has broad authority under federal law to impose safety-related, security-related and other licensing requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generation facilities, including Palo Verde. As a result of the March 2011 earthquake and tsunamis that caused significant damage to the Fukushima Daiichi Nuclear Power Plant in Japan, various industry organizations are working to analyze information from the Japan incident and develop action plans for U.S. nuclear power plants. Additionally, the NRC has been performing its own independent review of the events at Fukushima Daiichi, including a review of the agency s processes and regulations in order to determine whether the agency should promulgate additional regulations and possibly make more fundamental changes to the NRC s system of regulation. We cannot predict when or if the NRC will complete its formal actions as a result of its review. As a result of the Fukushima event, however, the NRC has directed nuclear power plants to implement the first tier recommendations of the NRC s Near Term Task Force. In response to these recommendations, Palo Verde expects to spend approximately $100 million for capital enhancements to the plant over the next several years (APS s share is 29.1%). We cannot predict whether these amounts will increase or whether additional financial and/or operational requirements on Palo Verde and APS may be imposed.

In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increased inspection regime that could ultimately result in the shut-down of a unit or civil penalties, or both, depending upon the NRC s assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect APS s financial condition, results of operations and cash flows.

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APS is subject to numerous environmental laws and regulations, and changes in, or liabilities under, existing or new laws or regulations may increase APS s cost of operations or impact its business plans.

APS is, or may become, subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, discharges of wastewater and streams originating from fly ash and bottom ash handling facilities, solid waste, hazardous waste, and coal combustion products, which consist of bottom ash, fly ash, and air pollution control wastes. These laws and regulations can result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require APS to obtain and comply with a wide variety of environmental licenses, permits, and other approvals. If there is a delay or failure to obtain any required environmental regulatory approval, or if APS fails to obtain, maintain, or comply with any such approval, operations at affected facilities could be suspended or subject to additional expenses. In addition, failure to comply with applicable environmental laws and regulations could result in civil liability as a result of government enforcement actions or private claims or criminal penalties. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. APS cannot predict the outcome (financial or operational) of any related litigation that may arise.

Environmental Clean Up. APS has been named as a PRP for a Superfund site in Phoenix, Arizona, and it could be named a PRP in the future for other environmental clean-up at sites identified by a regulatory body. APS cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs.

Regional Haze. APS has received final rulemakings imposing new requirements on Four Corners and Cholla and is currently awaiting a final rulemaking from EPA that could impose new requirements on the Navajo Plant. EPA and ADEQ will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants. The financial impact of installing and operating the required pollution control equipment could jeopardize the economic viability of these plants or the ability of individual participants to continue their participation in these plants.

Mercury and other Hazardous Air Pollutants. EPA issued MATS to regulate emissions of mercury and other hazardous air pollutants from fossil-fired power plants. The MATS will require APS to install additional pollution control equipment at Cholla and possibly the Navajo Plant. The financial impact of installing and operating such equipment could jeopardize the economic viability of Cholla.

Coal Ash. EPA released proposed regulations governing the disposal of CCRs, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. EPA proposed regulating CCRs as either non-hazardous or hazardous waste. APS currently disposes of CCRs in ash ponds and dry storage areas at Four Corners and Cholla, and also sells a portion of its fly ash for beneficial reuse as a constituent in concrete products. If EPA regulates CCRs as a hazardous solid waste or phases out APS s ability to dispose of CCRs through the use of ash ponds, APS could incur significant costs for CCR disposal and may be unable to continue its sale of fly ash for beneficial reuse.

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Effluent Limitation Guidelines. EPA is expected to finalize revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired electric generating units in 2014. EPA has indicated that it expects the revised standards to target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities and scrubber-related operations. APS currently disposes of fly ash waste and bottom ash in ash ponds at Four Corners. Changes required by the rule could significantly increase ash disposal costs at Four Corners.

New Source Review. EPA has taken the position that many projects electric utilities have performed are major modifications that trigger New Source Review requirements under the Clean Air Act. The utilities generally have taken the position that these projects are routine maintenance, repair and replacement and did not result in emissions increases, and thus are not subject to New Source Review. In 2009, APS received and responded to a request from EPA regarding projects and operations at Four Corners. Several environmental non-governmental organizations filed suit against the Four Corners participants for alleged violations of New Source Review and the NSPS programs of the Clean Air Act. If EPA seeks to impose New Source Review requirements at Four Corners or any other APS plant, or if the citizens groups prevail in their Clean Air Act lawsuit, capital investments could be required to install new pollution control technologies. EPA could also seek civil penalties.

APS cannot assure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to it. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs incurred by APS are not fully recoverable from APS s customers, could have a material adverse effect on its financial condition, results of operations or cash flows. Due to current or potential future regulations or legislation, the economics of continuing to own certain resources, particularly coal facilities, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

APS faces physical and operational risks related to climate change, and potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG emissions.

Concern over climate change, deemed by many to be induced by rising levels of GHG in the atmosphere, has led to significant legislative and regulatory efforts to limit CO_2, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions.

Financial Risks Potential Greenhouse Gas Regulation. EPA is taking action to regulate domestic GHG emissions and is expected to issue proposed regulations in mid-2014. Any limitations on CO_2 and other GHG emissions resulting from this regulatory effort could require substantial additional capital expenditures and operating costs and could have a material adverse impact on all fossil-fuel-fired generation facilities (particularly coal-fired facilities, which constitute approximately 30% of APS s owned and leased generation capacity).

At the state level, the California legislature enacted legislation to address GHG emissions and the California Air Resources Board approved regulations that established a cap-and-trade program for

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GHGs. This legislation, regulations and other state-specific initiatives may affect APS s business, including sales into the impacted states.

Physical and Operational Risks. Weather extremes such as drought and high temperature variations are common occurrences in the Southwest s desert area, and these are risks that APS considers in the normal course of business in the engineering and construction of its electric system. Large increases in ambient temperatures could require evaluation of certain materials used within its system and represent a greater challenge.

Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on APS s business and its results of operations.

In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on APS due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Although some very limited retail competition existed in APS s service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APS s customers. On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a market basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. One of these options could be a continuation or expansion of APS s existing AG (Alternative Generation) 1 program, which essentially allows up to 200 MW of cumulative load to be served via a buy-through arrangement with competitive suppliers of generation. We cannot predict future regulatory or legislative action that might result in increased competition.

In 2010, the ACC issued a decision holding that solar vendors that install and operate solar facilities for non-profit schools and governments pursuant to a specific type of contract that calculates payments based on the energy produced are not public service corporations under the Arizona Constitution, and are therefore not regulated by the ACC. A second matter is pending with the ACC to determine whether that ruling should extend to solar providers who serve a broader customer base under the same business model. The use of such products by customers within our territory would result in some level of competition. APS cannot predict whether the ACC will deem these vendors public service corporations subject to ACC regulation and when, and the extent to which, additional service providers will enter APS s service territory, increasing the level of competition in the market.

OPERATIONAL RISKS

APS s results of operations can be adversely affected by various factors impacting demand for electricity.

Weather Conditions. Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In

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Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, APS s overall operating results fluctuate substantially on a seasonal basis. In addition, APS has historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish APS s financial condition, results of operations and cash flows.

Higher temperatures may decrease the snowpack, which might result in lowered soil moisture and an increased threat of forest fires. Forest fires could threaten APS s communities and electric transmission lines and facilities. Any damage caused as a result of forest fires could negatively impact APS s financial condition, results of operations or cash flows.

Effects of Energy Conservation Measures and Distributed Energy. The ACC has enacted rules regarding energy efficiency that mandate a 22% annual energy savings requirement by 2020. This will likely increase participation by APS customers in energy efficiency and conservation programs and other demand-side management efforts, which in turn will impact the demand for electricity. The rules also include a requirement for the ACC to review and address financial disincentives, recovery of fixed costs and the recovery of net lost income/revenue that would result from lower sales due to increased energy efficiency requirements. To that end, the settlement agreement in APS s most recent retail rate case (the 2012 Settlement Agreement) includes a mechanism, the LFCR, to address these matters.

APS must also meet certain distributed energy requirements. A portion of APS s total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small scale renewable technologies located on customers properties). The distributed energy requirement was 25% of the overall RES requirement of 3% in 2011 and increased to 30% of the applicable RES requirement for 2012 and subsequent years. Customer participation in distributed energy programs would result in lower demand, since customers would be meeting some or all of their own energy needs. Reduced demand due to these energy efficiency and distributed energy requirements, unless substantially offset through ratemaking mechanisms, could have a material adverse impact on APS s financial condition, results of operations and cash flows.

Customer and Sales Growth. For the three years 2011 through 2013, APS s retail customer growth averaged 1.0% per year. We currently expect annual customer growth to average about 2.5% for 2014 through 2016 based on our assessment of modestly improving economic conditions, both nationally and in Arizona. For the three years 2011 through 2013, APS experienced annual increases in retail electricity sales averaging 0.1%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average by about 1% during 2014 through 2016, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. Actual customer and sales growth may differ from our projections as a result of numerous factors, such as economic conditions, customer growth and usage patterns, and the effects of energy efficiency and distributed energy programs and requirements. Additionally, recovery of a substantial portion of our fixed costs of providing service is based upon the volumetric amount of our sales. If our customer growth rate does not continue to improve as projected, or if it declines, or if the Arizona economy fails to improve, we may be unable to reach our estimated demand level and sales projections, which could have a negative impact on our financial condition, results of operations and cash flows.

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The operation of power generation facilities and transmission systems involves risks that could result in reduced output or unscheduled outages, which could materially affect APS s results of operations.

The operation of power generation, transmission and distribution facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption, and performance below expected levels of output or efficiency. Unscheduled outages, including extensions of scheduled outages due to mechanical failures or other complications, occur from time to time and are an inherent risk of APS s business. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the larger transmission power grid, and the operation or failure of our facilities could adversely affect the operations of others. If APS s facilities operate below expectations, especially during its peak seasons, it may lose revenue or incur additional expenses, including increased purchased power expenses. Concerns over physical security of these assets is also increasing, which may require us to incur additional capital and operating costs to address. Damage to certain of our facilities due to vandalism or other deliberate acts could lead to outages or other adverse effects.

The inability to successfully develop or acquire generation resources to meet reliability requirements, new or evolving standards or regulations could adversely impact our business.

Potential changes in regulatory standards, impacts of new and existing laws and regulations, including environmental laws and regulations, and the need to obtain certain regulatory approvals create uncertainty surrounding our generation portfolio. The current abundance of low, stably priced natural gas, together with environmental and other concerns surrounding coal-fired generation resources, create strategic questions related to the appropriate generation portfolio and fuel diversification mix. In addition, APS is required by the ACC to meet certain energy resource portfolio requirements such as the EES and the RES. The development of any generation facility is subject to many risks, including risks related to financing, siting, permitting, technology, the construction of sufficient transmission capacity to support these facilities and stresses to generation and transmission resources from intermittent generation characteristics of renewable resources. APS s inability to adequately develop or acquire the necessary generation resources could have a material adverse impact on our business and results of operations.

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

Assured supplies of water are important for APS s generating plants. Water in the southwestern United States is limited, and various parties have made conflicting claims regarding the right to access and use such limited supply of water. Both groundwater and surface water in areas important to APS s generating plants have been and are the subject of inquiries, claims and legal proceedings. In addition, the region in which APS s power plants are located is prone to drought conditions, which could potentially affect the plants water supplies. APS s inability to access sufficient supplies of water could have a material adverse impact on our business and results of operations.

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The ownership and operation of power generation and transmission facilities on Indian lands could result in uncertainty related to continued leases, easements and rights-of-way, which could have a significant impact on our business.

Certain APS power plants, including Four Corners, and portions of the transmission lines that carry power from these plants are located on Indian lands pursuant to leases, easements or other rights-of-way that are effective for specified periods. APS is currently unable to predict the final outcome of pending and future approvals by applicable governing bodies with respect to renewals of these leases, easements and rights-of-way.

There are inherent risks in the ownership and operation of nuclear facilities, such as environmental, health, fuel supply, spent fuel disposal, regulatory and financial risks and the risk of terrorist attack.

APS has an ownership interest in and operates, on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the United States. Palo Verde constitutes approximately 18% of our owned and leased generation capacity. Palo Verde is subject to environmental, health and financial risks, such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. In addition, APS may be required under federal law to pay up to $111 million (but not more than $16.4 million per year) of liabilities arising out of a nuclear incident occurring not only at Palo Verde, but at any other nuclear power plant in the United States. Although we have no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

APS s operations include managing market risks related to commodity prices. APS is exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas and coal to the extent that unhedged positions exist. We have established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange traded futures and options and over-the-counter forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time and financial losses that negatively impact our results of operations.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) contains measures aimed at increasing the transparency and stability of the over-the counter, or OTC, derivative markets and preventing excessive speculation. The Dodd-Frank Act could restrict, among

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other things, trading positions in the energy futures markets, require different collateral or settlement positions, or increase regulatory reporting over derivative positions. Based on the provisions included in the Dodd-Frank Act and the implementation of regulations, these changes could, among other things, impact our ability to hedge commodity price and interest rate risk or increase the costs associated with our hedging programs.

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of all counterparties. Despite the fact that the majority of APS s trading counterparties are rated as investment grade by the rating agencies, there is still a possibility that one or more of these companies could default, which could result in a material adverse impact on our earnings for a given period.

Changes in technology could create challenges for APS s existing business.

Research and development activities are ongoing to assess alternative technologies that produce power or reduce power consumption or emissions, including clean coal and coal gasification, renewable technologies including photovoltaic (solar) cells, customer-sited generation (solar), energy storage (batteries), and efficiency technologies, and improvements in traditional technologies and equipment, such as more efficient gas turbines. Advances in these, or other technologies could reduce the cost of power production, making APS s existing generating facilities less economical. In addition, advances in technology and equipment/appliance efficiency could reduce the demand for power supply, which could adversely affect APS s business.

APS is pursuing and implementing smart grid technologies, including advanced transmission and distribution system technologies, as well as digital meters enabling two-way communications between the utility and its customers. Many of the products and processes resulting from these and other alternative technologies have not yet been widely used or tested on a long-term basis, and their use on large-scale systems is not as advanced and established as APS s existing technologies and equipment. Widespread installation and acceptance of these technologies could enable the entry of new market participants, such as technology companies, into the interface between APS and its customers and could have other unpredictable effects on APS s business.

We are subject to employee workforce factors that could adversely affect our business and financial condition.

Like most companies in the electric utility industry, our workforce is aging, with approximately 38% of employees eligible to retire by 2017. Although we have undertaken efforts to recruit and train new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability of qualified personnel, the need to negotiate collective bargaining agreements with union employees and potential work stoppages. These or other employee workforce factors could negatively impact our business, financial condition or results of operations.

We are subject to information security risks and risks of unauthorized access to our systems.

In the regular course of our business, we handle a range of sensitive security, customer and business systems information. We are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of our information systems such as theft or the inappropriate release of certain types of information, including

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confidential customer, employee, financial or system operating information, could have a material adverse impact on our financial condition, results of operations or cash flows.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, our technology systems are vulnerable to disability, failures or unauthorized access. Our generation, transmission and distribution facilities, information technology systems and other infrastructure facilities and systems and physical assets could be targets of such unauthorized access. Failures or breaches of our systems could impact the reliability of our generation, transmission and distribution systems and also subject us to financial harm. If our technology systems were to fail or be breached and if we are unable to recover in a timely way, we may not be able to fulfill critical business functions and sensitive confidential data could be compromised, which could have a material adverse impact on our financial condition, results of operations or cash flows.

The implementation of security measures could increase costs and have a material adverse impact on our financial results. These types of events could also require significant management attention and resources, and could adversely affect Pinnacle West s and APS s reputation with customers and the public. We obtained cyber insurance to provide coverage for a portion of the losses and damages that may result from a security breach of our information technology systems, but such insurance may not cover the total loss or damage caused by a breach.

FINANCIAL RISKS

Financial market disruptions or new financial rules or regulations may increase our financing costs or limit our access to various financial markets, which may adversely affect our liquidity and our ability to implement our financial strategy.

Pinnacle West and APS rely on access to credit markets as a significant source of liquidity and the capital markets for capital requirements not satisfied by cash flow from our operations. We believe that we will maintain sufficient access to these financial markets. However, certain market disruptions or rules or regulations may increase our cost of borrowing generally, and/or otherwise adversely affect our ability to access these financial markets.

In addition, the credit commitments of our lenders under our bank facilities may not be satisfied for a variety of reasons, including periods of financial distress or liquidity issues affecting our lenders, which could materially adversely affect the adequacy of our liquidity sources.

Changes in economic conditions, monetary policy or other factors could result in higher interest rates, which would increase interest expense on our existing variable rate debt and new debt we expect to issue in the future, and thus reduce funds available to us for our current plans. Additionally, an increase in our leverage could adversely affect us by:

- causing a downgrade of our credit ratings;
- increasing the cost of future debt financing and refinancing;

- increasing our vulnerability to adverse economic and industry conditions; and
- requiring us to dedicate an increased portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes.

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A downgrade of our credit ratings could materially and adversely affect our business, financial condition and results of operations.

Our current ratings are set forth in Liquidity and Capital Resources Credit Ratings in Item 7. We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade or withdrawal could adversely affect the market price of Pinnacle West s and APS s securities, limit our access to capital and increase our borrowing costs, which would diminish our financial results. We would be required to pay a higher interest rate for future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under our existing credit facilities depend on our credit ratings. A downgrade would also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could severely limit access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating.

Investment performance, changing interest rates and other economic factors could decrease the value of our benefit plan assets and nuclear decommissioning trust funds and increase the valuation of our related obligations, resulting in significant additional funding requirements. We are subject to risks related to the provision of employee healthcare benefits and recent healthcare reform legislation. Any inability to fully recover these costs in our utility rates would negatively impact our financial condition.

We have significant pension plan and other postretirement benefits plan obligations to our employees and retirees and legal obligations to fund nuclear decommissioning trusts for Palo Verde. We hold and invest substantial assets in these trusts that are designed to provide funds to pay for certain of these obligations as they arise. Declines in market values of the fixed income and equity securities held in these trusts may increase our funding requirements into the related trusts. Additionally, the valuation of liabilities related to our pension plan and other postretirement benefit plans are impacted by a discount rate, which is the interest rate used to discount future pension and other postretirement benefit obligations. Declining interest rates decrease the discount rate, increase the valuation of the plan liabilities and may result in increases in pension and other postretirement benefit costs, cash contributions, regulatory assets, and charges to OCI. Changes in demographics, including increased numbers of retirements or changes in life expectancy and changes in other actuarial assumptions, may also increase the funding requirements of the obligations related to the pension and other postretirement benefit plans. The minimum contributions required under these plans are impacted by federal legislation. Increasing liabilities or otherwise increasing funding requirements under these plans, resulting from adverse changes in legislation or otherwise, could result in significant cash funding obligations that could have a material impact on our financial position, results of operations or cash flows.

We recover most of the pension costs and other postretirement benefit costs and all of the nuclear decommissioning costs in our regulated rates. Any inability to fully recover these costs in a timely manner would have a material negative impact on our financial condition, results of operations or cash flows.

Employee healthcare costs in recent years have continued to rise. The Patient Protection and Affordable Care Act is expected to result in additional healthcare cost increases. Costs and other

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effects of the legislation, which may include the cost of compliance and potentially increased costs of providing for medical insurance for our employees, cannot be determined with certainty at this time. We will continue to monitor healthcare legislation and its impact on our plans and costs.

Our cash flow depends on the performance of APS.

We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. Accordingly, our cash flow and our ability to pay dividends on our common stock is dependent upon the earnings and cash flows of APS and its distributions to us. APS is a separate and distinct legal entity and has no obligation to make distributions to us.

APS s financing agreements may restrict its ability to pay dividends, make distributions or otherwise transfer funds to us. In addition, an ACC financing order requires APS to maintain a common equity ratio of at least 40% and does not allow APS to pay common dividends if the payment would reduce its common equity below that threshold. The common equity ratio, as defined in the ACC order, is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt.

Pinnacle West s ability to meet its debt service obligations could be adversely affected because its debt securities are structurally subordinated to the debt securities and other obligations of its subsidiaries.

Because Pinnacle West is structured as a holding company, all existing and future debt and other liabilities of our subsidiaries will be effectively senior in right of payment to our debt securities. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations. Our ability to have the benefit of their cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors have been satisfied.

The market price of our common stock may be volatile.

The market price of our common stock could be subject to significant fluctuations in response to factors such as the following, some of which are beyond our control:

- variations in our quarterly operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;

- developments generally affecting industries in which we operate;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- announcements by third parties of significant claims or proceedings against us;
- favorable or adverse regulatory or legislative developments;
- our dividend policy;
- future sales by the Company of equity or equity-linked securities; and
- general domestic and international economic conditions.

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In addition, the stock market in general has experienced volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock.

Certain provisions of our articles of incorporation and bylaws and of Arizona law make it difficult for shareholders to change the composition of our board and may discourage takeover attempts.

These provisions, which could preclude our shareholders from receiving a change of control premium, include the following:

- restrictions on our ability to engage in a wide range of business combination transactions with an interested shareholder (generally, any person who owns 10% or more of our outstanding voting power or any of our affiliates or associates) or any affiliate or associate of an interested shareholder, unless specific conditions are met;

- anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied;

- the ability of the Board of Directors to increase the size of the Board of Directors and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise; and

- the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval.

While these provisions have the effect of encouraging persons seeking to acquire control of us to negotiate with our Board of Directors, they could enable the Board of Directors to hinder or frustrate a transaction that some, or a majority, of our shareholders might believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Neither Pinnacle West nor APS has received written comments regarding its periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of its 2013 fiscal year and that remain unresolved.

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ITEM 2. PROPERTIES

Generation Facilities

APS s portfolio of owned and leased generating facilities is provided in the table below:

Name	No. of Units	% Owned (a)	Principal Fuels Used	Primary Dispatch Type	Owned Capacity (MW)
Nuclear:					
Palo Verde (b)	3	29.1%	Uranium	Base Load	1,146
Total Nuclear					1,146
Steam:					
Four Corners 4, 5 (c)	2	63%	Coal	Base Load	970
Cholla	3		Coal	Base Load	647
Navajo (d)	3	14%	Coal	Base Load	315
Ocotillo	2		Gas	Peaking	220
Total Steam					2,152
Combined Cycle:					
Redhawk	2		Gas	Load Following	984
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,871
Combustion Turbine:					
Ocotillo	2		Gas	Peaking	110
Saguaro 1, 2	2		Gas/Oil	Peaking	110
Saguaro 3	1		Gas	Peaking	79
Douglas	1		Oil	Peaking	16
Sundance	10		Gas	Peaking	420
West Phoenix	2		Gas	Peaking	110
Yucca 1, 2, 3	3		Gas/Oil	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	96
Total Combustion Turbine					1,088
Solar:					
Cotton Center	1		Solar	As Available	17
Hyder	1		Solar	As Available	16
Paloma	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	19
Hyder II	1		Solar	As Available	14
Foothills	1		Solar	As Available	35
APS Owned Distributed Energy			Solar	As Available	15
Multiple facilities			Solar	As Available	4
Total Solar					137
Total Capacity					6,394

(a) 100% unless otherwise noted.

(b) See Business of Arizona Public Service Company Energy Sources and Resource Planning Generation Facilities Nuclear in Item 1 for details regarding leased

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interests in Palo Verde. The other participants are Salt River Project (17.49%), SCE (15.8%), El Paso (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water & Power (5.7%). The plant is operated by APS.

(c) The other participants are Salt River Project (10%), Public Service Company of New Mexico (13%), Tucson Electric Power Company (7%) and El Paso (7%). The plant is operated by APS. As discussed under Business of Arizona Public Service Company Energy Sources and Resource Planning Generation Facilities Coal-Fueled Generating Facilities Four Corners in Item 1, in December 2013 APS acquired SCE s 48% interest in Units 4 and 5, and closed Units 1, 2 and 3.

(d) The other participants are Salt River Project (21.7%), Nevada Power Company (11.3%), the United States Government (24.3%), Tucson Electric Power Company (7.5%) and Los Angeles Department of Water & Power (21.2%). The plant is operated by Salt River Project.

See Business of Arizona Public Service Company Environmental Matters in Item 1 with respect to matters having a possible impact on the operation of certain of APS s generating facilities.

See Business of Arizona Public Service Company in Item 1 for a map detailing the location of APS s major power plants and principal transmission lines.

Transmission and Distribution Facilities

Current Facilities. APS s transmission facilities consist of approximately 5,908 pole miles of overhead lines and approximately 49 miles of underground lines, 5,685 miles of which are located in Arizona. APS s distribution facilities consist of approximately 11,399 miles of overhead lines and approximately 17,758 miles of underground primary cable, all of which are located in Arizona. APS shares ownership of some of its transmission facilities with other companies. The following table shows APS s jointly-owned interests in those transmission facilities recorded on the Consolidated Balance Sheets at December 31, 2013:

	Percent Owned (Weighted-Average)
Morgan Pinnacle Peak System	64.5%
Palo Verde Estrella 500kV System	50.0%
Round Valley System	50.0%
ANPP 500kV System	34.2%
Navajo Southern System	22.2%
Four Corners Switchyards	48.1%
Palo Verde Yuma 500kV System	18.0%
Phoenix Mead System	17.1%
Palo Verde Morgan System	90.0%

Expansion. Each year APS prepares and files with the ACC a ten-year transmission plan. In APS s 2014 plan, APS projects it will develop 275 miles of new lines over the next ten years. One significant project currently under development is a new 500kV path that will span from the Palo Verde hub around the western and northern edges of the Phoenix metropolitan area and terminate at a bulk substation in the northeast part of Phoenix. The project consists of four phases. The first phase,

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Morgan to Pinnacle Peak 500kV, is currently in-service. The second phase, Delaney to Palo Verde 500kV, is under construction. The third and fourth phases, Delaney to Sun Valley 500kV and Morgan to Sun Valley 500kV, have been permitted and are in various stages of final design and development. In total, the projects consist of over 100 miles of new 500kV lines, with many of those miles constructed with the capability to string a 230kV line as a second circuit.

APS continues to work with regulators to identify transmission projects necessary to support renewable energy facilities. Two such projects, which are included in APS s 2014 transmission plan, are the Delaney to Palo Verde line and the North Gila to Hassayampa line, both of which are intended to support the transmission of renewable energy to Phoenix and California.

Plant and Transmission Line Leases and Rights-of-Way on Indian Lands

The Navajo Plant and Four Corners are located on land held under leases from the Navajo Nation and also under rights-of-way from the federal government. The right-of-way and lease for the Navajo Plant expire in 2019 and the right-of-way and lease for Four Corners expire in 2016. On March 7, 2011, the Navajo Nation Council signed a resolution approving a 25-year extension to the existing Four Corners lease term and providing Navajo Nation consent to renewal of the related rights-of-way. APS is filing applications for renewal of these rights-of-way with the DOI. Before it may approve the Four Corners lease extension and issue the renewed rights-of-way, the United States must complete an analysis under the federal National Environmental Policy Act, the ESA and related statutes.

Certain portions of the transmission lines that carry power from several of our power plants are located on Indian lands pursuant to rights-of-way that are effective for specified periods. Some of these rights-of-way have expired and our renewal applications have not yet been acted upon by the appropriate Indian tribes or federal agencies. Other rights expire at various times in the future and renewal action by the applicable tribe or federal agencies will be required at that time. In recent negotiations, certain of the affected Indian tribes have required payments substantially in excess of amounts that we have paid in the past for such rights-of-way. The ultimate cost of renewal of the rights-of-way for our transmission lines is therefore uncertain.

ITEM 3. LEGAL PROCEEDINGS

See Business of Arizona Public Service Company Environmental Matters in Item 1 with regard to pending or threatened litigation and other disputes.

See Note 3 for ACC and FERC-related matters.

See Note 11 for information regarding environmental matters, Superfund related matters, matters related to a September 2011 power outage and a New Mexico tax matter.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF PINNACLE WEST

Pinnacle West s executive officers are elected no less often than annually and may be removed by the Board of Directors at any time. The executive officers, their ages at February 21, 2014, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Donald E. Brandt	59	Chairman of the Board and Chief Executive Officer of Pinnacle West; Chairman of the Board of APS	2009-Present
		President of APS	2013-Present
		President of Pinnacle West	2008-Present
		Chief Executive Officer of APS	2008-Present
		Chief Operating Officer of Pinnacle West	2008-2009
		President of APS	2006-2009
		Executive Vice President of Pinnacle West; Chief Financial Officer of APS	2003-2008
		Executive Vice President of APS	2003-2006
		Chief Financial Officer of Pinnacle West	2002-2008
Robert S. Bement	58	Senior Vice President, Site Operations, PVNGS, of APS	2010-Present
		Vice President, Nuclear Operations of APS	2007-2010
Denise R. Danner	58	Vice President, Controller and Chief Accounting Officer of Pinnacle West; Chief Accounting Officer of APS	2010-Present
		Vice President and Controller of APS	2009-Present
		Senior Vice President, Controller and Chief Accounting Officer of Allied Waste Industries, Inc.	2007-2008
Patrick Dinkel	50	Vice President, Transmission and Distribution Operations of APS	2014-Present
		Vice President, Resource Management of APS	2012-2014
		Vice President, Power Marketing, Resource Planning and Acquisition of APS	2011-2012
		Vice President, Power Marketing and Resource Planning of APS	2010-2011
		General Manager, Strategic Planning and Resource Acquisition of APS	2009-2010
		Director of Resource Acquisitions and Renewables of APS	2007-2009
Randall K. Edington	60	Executive Vice President and Chief Nuclear Officer, PVNGS, of APS	2007-Present
		Senior Vice President and Chief Nuclear Officer of APS	2007

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Name	Age	Position	Period
David P. Falck	60	Executive Vice President and General Counsel of Pinnacle West and APS	2009-Present
		Secretary of Pinnacle West and APS	2009-2012
		Senior Vice President Law of Public Service Enterprise Group Inc.	2007-2009
Daniel T. Froetscher	52	Senior Vice President, Transmission, Distribution & Customers of APS	2014-Present
		Vice President, Energy Delivery of APS	2008-2014
Jeffrey B. Guldner	48	Senior Vice President, Public Policy of APS	2014-Present
		Senior Vice President, Customers and Regulation of APS	2012-2014
		Vice President, Rates and Regulation of APS	2007-2012
James R. Hatfield	56	Executive Vice President of Pinnacle West and APS	2012-Present
		Chief Financial Officer of Pinnacle West and APS	2008-Present
		Senior Vice President of Pinnacle West and APS	2008-2012
		Treasurer of Pinnacle West and APS	2009-2010
John S. Hatfield	48	Vice President, Communications of APS	2010-Present
		Director, Corporate Communications of SCE	2004-2010
Tammy D. McLeod	52	Vice President, Resource Management of APS	2014-Present
		Vice President and Chief Customer Officer of APS	2007-2014
Lee R. Nickloy	47	Vice President and Treasurer of Pinnacle West and APS	2010-Present
		Assistant Treasurer and Director Corporate Finance of Ameren Corporation	2000-2010
Mark A. Schiavoni	58	Executive Vice President, Operations of APS	2012-Present
		Senior Vice President, Fossil Operations of APS	2009-2012
		Senior Vice President of Exelon Generation and President of Exelon Power	2004-2009

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PART II

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

Pinnacle West s common stock is publicly held and is traded on the New York Stock Exchange. At the close of business on February 14, 2014, Pinnacle West s common stock was held of record by approximately 23,053 shareholders.

QUARTERLY STOCK PRICES AND DIVIDENDS PAID PER SHARE

STOCK SYMBOL: PNW

2013	**High**	**Low**	**Close**	**Dividends Per Share**
1st Quarter	$ 57.96	$ 51.50	$ 57.89	$ 0.545
2nd Quarter	61.89	51.56	55.47	0.545
3rd Quarter	60.33	52.03	54.74	0.545
4th Quarter	58.70	52.32	52.92	0.5675

2012	**High**	**Low**	**Close**	**Dividends Per Share**
1st Quarter	$ 48.86	$ 46.15	$ 47.90	$ 0.525
2nd Quarter	52.30	45.95	51.74	0.525
3rd Quarter	54.66	51.19	52.80	0.525
4th Quarter	54.20	48.73	50.98	0.545

APS s common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. As a result, there is no established public trading market for APS s common stock.

The chart below sets forth the dividends paid on APS s common stock for each of the four quarters for 2013 and 2012.

Common Stock Dividends

(Dollars in Thousands)

Quarter		2013		2012
1st Quarter	$	59,800	$	57,400
2nd Quarter		59,900		47,500
3rd Quarter		59,900		57,500
4th Quarter		62,500		59,800

The sole holder of APS s common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. As of December 31, 2013, APS did not have any outstanding preferred stock.

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Issuer Purchases of Equity Securities

The following table contains information about our purchases of our common stock during the fourth quarter of 2013.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 October 31, 2013	60,823	$ 57.56		
November 1 November 30, 2013				
December 1 December 31, 2013				
Total	60,823	$ 57.56		

(1) Represents shares of common stock withheld by Pinnacle West to satisfy tax withholding obligations upon the vesting of restricted stock and performance shares.

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ITEM 6. SELECTED FINANCIAL DATA

PINNACLE WEST CAPITAL CORPORATION CONSOLIDATED

	2013	2012	2011	2010	2009
		(dollars in thousands, except per share amounts)			
OPERATING RESULTS					
Operating revenues	$ 3,454,628	$ 3,301,804	$ 3,241,379	$ 3,189,199	$ 3,153,656
Income from continuing operations	$ 439,966	$ 418,993	$ 355,634	$ 344,851	$ 256,048
Income (loss) from discontinued operations net of income taxes (a)		(5,829)	11,306	25,358	(183,284)
Net income	439,966	413,164	366,940	370,209	72,764
Less: Net income attributable to noncontrolling interests	33,892	31,622	27,467	20,156	4,434
Net income attributable to common shareholders	$ 406,074	$ 381,542	$ 339,473	$ 350,053	$ 68,330
COMMON STOCK DATA					
Book value per share year-end	$ 38.07	$ 36.20	$ 34.98	$ 33.86	$ 32.69
Earnings per weighted-average common share outstanding:					
Continuing operations attributable to common shareholders basic	$ 3.69	$ 3.54	$ 3.01	$ 3.05	$ 2.34
Net income attributable to common shareholders basic	$ 3.69	$ 3.48	$ 3.11	$ 3.28	$ 0.68
Continuing operations attributable to common shareholders diluted	$ 3.66	$ 3.50	$ 2.99	$ 3.03	$ 2.34
Net income attributable to common shareholders diluted	$ 3.66	$ 3.45	$ 3.09	$ 3.27	$ 0.67
Dividends declared per share	$ 2.23	$ 2.67	$ 2.10	$ 2.10	$ 2.10
Weighted-average common shares outstanding basic	109,984,160	109,510,296	109,052,840	106,573,348	101,160,659
Weighted-average common shares outstanding diluted	110,805,943	110,527,311	109,864,243	107,137,785	101,263,795
BALANCE SHEET DATA					
Total assets	$ 13,508,686	$ 13,379,615	$ 13,111,018	$ 12,392,998	$ 12,035,253
Liabilities and equity:					
Current liabilities	$ 1,618,644	$ 1,083,542	$ 1,342,705	$ 1,449,704	$ 1,279,288
Long-term debt less current maturities	2,796,465	3,199,088	3,019,054	3,045,794	3,496,524
Deferred credits and other	4,753,117	4,994,696	4,818,673	4,122,274	3,831,437
Total liabilities	9,168,226	9,277,326	9,180,432	8,617,772	8,607,249
Total equity	4,340,460	4,102,289	3,930,586	3,775,226	3,428,004
Total liabilities and equity	$ 13,508,686	$ 13,379,615	$ 13,111,018	$ 12,392,998	$ 12,035,253

(a) Amounts primarily related to SunCor and APSES discontinued operations (see Note 1).

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SELECTED FINANCIAL DATA

ARIZONA PUBLIC SERVICE COMPANY CONSOLIDATED

	2013	2012	2011	2010	2009
			(dollars in thousands)		
OPERATING RESULTS					
Electric operating revenues	$ 3,451,251	$ 3,293,489	$ 3,237,241	$ 3,180,807	$ 3,149,500
Fuel and purchased power costs	1,095,709	994,790	1,009,464	1,046,815	1,178,620
Other operating expenses	1,733,677	1,693,170	1,673,394	1,584,955	1,501,081
Operating income	621,865	605,529	554,383	549,037	469,799
Other income	20,797	16,358	24,974	20,138	13,893
Interest expense net of allowance for borrowed funds	183,801	194,777	215,584	213,349	213,258
Net income	458,861	427,110	363,773	355,826	270,434
Less: Net income attributable to noncontrolling interests	33,892	31,613	27,524	20,163	19,209
Net income attributable to common shareholder	$ 424,969	$ 395,497	$ 336,249	$ 335,663	$ 251,225
BALANCE SHEET DATA					
Total assets	$ 13,381,377	$ 13,242,542	$ 13,032,237	$ 12,271,877	$ 11,730,500
Liabilities and equity:					
Total equity	$ 4,454,874	$ 4,222,483	$ 4,051,406	$ 3,916,037	$ 3,527,679
Long-term debt less current maturities	2,671,465	3,074,088	2,894,054	3,045,794	3,306,406
Total capitalization	7,126,339	7,296,571	6,945,460	6,961,831	6,834,085
Current liabilities	1,580,847	1,043,087	1,322,714	1,234,865	1,070,970
Deferred credits and other	4,674,191	4,902,884	4,764,063	4,075,181	3,825,445
Total liabilities and equity	$ 13,381,377	$ 13,242,542	$ 13,032,237	$ 12,271,877	$ 11,730,500

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with Pinnacle West s Consolidated Financial Statements and APS s Consolidated Financial Statements and the related Notes that appear in Item 8 of this report. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see Forward-Looking Statements at the front of this report and Risk Factors in Item 1A.

OVERVIEW

Pinnacle West owns all of the outstanding common stock of APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS accounts for essentially all of our revenues and earnings, and is expected to continue to do so.

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. APS operates and is a joint owner of Palo Verde. The March 2011 earthquake and tsunamis in Japan and the resulting accident at Japan s Fukushima Daiichi nuclear power station had a significant impact on nuclear power operators worldwide. In the aftermath of the accident, the NRC conducted an independent assessment to consider actions to ensure that its regulations reflect lessons learned from the Fukushima events.

Although the NRC has repeatedly affirmed its position that continued operation of U.S. commercial nuclear power plants does not impose an immediate risk to public health and safety, the NRC has proposed enhancements to U.S. commercial nuclear power plant equipment and emergency plans. APS management continues to work closely with the NRC and others in the nuclear industry to ensure that the enhancements are implemented in an organized, sequential and structured way consistent with their safety benefit and significance of the issue being addressed.

Coal and Related Environmental Matters and Transactions. APS is a joint owner of three coal-fired power plants and acts as operating agent for two of the plants. APS is focused on the impacts on its coal fleet that may result from increased regulation and potential legislation concerning GHG emissions. Concern over climate change and other emission-related issues could have a significant impact on our capital expenditures and operating costs in the form of taxes, emissions allowances or required equipment upgrades for these plants. APS is closely monitoring its long-range capital management plans, understanding that any resulting regulation and legislation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to fund any such equipment upgrades.

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Four Corners

Asset Purchase Agreement and Coal Supply Matters. SCE, a participant in Four Corners, previously indicated that certain California legislation prohibited it from making emission control expenditures at the plant. On November 8, 2010, APS and SCE entered into the Asset Purchase Agreement, providing for the purchase by APS of SCE s 48% interest in each of Units 4 and 5 of Four Corners. On December 30, 2013, APS and SCE closed this transaction. The final purchase price for the interest was approximately $182 million, subject to certain minor post-closing adjustments.

In connection with APS s most recent retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 30, 2013, APS filed an application with the ACC to request rate adjustments prior to its next general rate case related to APS s acquisition of SCE s interest in Four Corners. If approved, these would result in an average bill impact to residential customers of approximately 2%. APS cannot predict the outcome of this request.

Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton will be retained by NTEC under contract as the mine manager and operator until July 2016. Also occurring concurrently with the closing, the Four Corners co-owners executed the 2016 Coal Supply Agreement. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has agreed to assume the 7% shortfall obligation. When APS ultimately acquires a right to EPE s interest in Four Corners, by agreement or operation of law, NTEC will have an option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not exercise its option.

Pollution Control Investments and Shutdown of Units 1, 2 and 3. EPA, in its final regional haze rule for Four Corners, required the Four Corners owners to elect one of two emissions alternatives to apply to the plant. On December 30, 2013, APS, on behalf of the co-owners, notified EPA that they chose the alternative BART compliance strategy requiring the permanent closure of Units 1, 2 and 3 by January 1, 2014 and installation and operation of SCR controls on Units 4 and 5 by July 31, 2018. On December 30, 2013, APS retired Units 1, 2 and 3.

Lease Extension. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also requires the approval of the DOI, as does a related federal rights-of-way grant which the Four Corners participants are pursuing. A federal environmental review is underway as part of the DOI review process. APS will also require a PSD permit from EPA to install SCR control technology at Four Corners. APS cannot predict whether these federal approvals will be granted, and if so on a timely basis, or whether any conditions that may be attached to them will be acceptable to the Four Corners owners.

Transmission and Delivery. APS is working closely with regulators to identify and plan for transmission needs that continue to support system reliability, access to markets and renewable energy development. The capital expenditures table presented in the Liquidity and Capital Resources section

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below includes new transmission projects through 2016, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand smart grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better monitor their energy use and needs, minimize system outage durations, as well as the number of customers that experience outages, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions, including remote meter reading and remote connects and disconnects.

***Renewable Energy*.** The ACC approved the RES in 2006. The renewable energy requirement is 4.5% of retail electric sales in 2014 and increases annually until it reaches 15% in 2025. In the 2009 Settlement Agreement, APS agreed to exceed the RES standards, committing to use APS s best efforts to obtain 1,700 GWh of new renewable resources to be in service by year-end 2015, in addition to its 2008 renewable resource commitments. Taken together, APS s commitment is currently estimated to be approximately 12% of APS s estimated retail energy sales by year-end 2015, which is more than double the existing RES target of 5% for that year. A component of the RES targets development of distributed energy systems (generally speaking, small-scale renewable technologies that are located on customers properties).

On July 12, 2013, APS filed its annual RES implementation plan, covering the 2014-2018 timeframe and requesting a 2014 RES budget of approximately $143 million. In a final order dated January 7, 2014, the ACC approved the requested budget. Also in 2013, the ACC conducted a hearing to consider APS s proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules so that utilities can establish compliance without using renewable energy credits.

On July 12, 2013, APS filed an application with the ACC proposing a solution to fix the cost shift brought by the current net metering rules. In its application, APS requested that the ACC cause all new residential customers installing new rooftop solar systems to either: (i) take electric service under APS s demand-based ECT-2 rate and remain eligible for net metering; or (ii) take service under the customer s existing rate as if no distributed energy system was installed and receive a bill credit for 100% of the distributed energy system s output at a market-based price. APS also proposed that the ACC: (i) grandfather current rates and use of net metering for existing and immediately pending distributed energy customers; and (ii) continue using direct cash incentives for new distributed energy installations.

On December 3, 2013, the ACC issued its order on APS s net metering proposal. The ACC instituted a charge on future customers who install rooftop solar panels and directed APS to provide quarterly reports on the pace of rooftop solar adoption to assist the ACC in considering further increases. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electricity grid. The new policy will be in effect until the next APS rate case.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electrical grid. ACC staff and the state s Residential Utility Consumer Office, among other organizations, also agreed that a cost shift exists. The fixed charge does not increase APS s revenue,

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but instead will modestly reduce the impact of the cost shift on non-solar customers. The ACC acknowledged that the new charge addresses only a portion of the cost shift.

Demand Side Management. In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated an Energy Efficiency rulemaking, with a proposed EES of 22% cumulative annual energy savings by 2020. The 22% figure represents the cumulative reduction in future energy usage through 2020 attributable to energy efficiency initiatives. This ambitious standard became effective on January 1, 2011. The ACC issued an order on April 4, 2012, approving recovery of approximately $72 million of APS s energy efficiency and demand side management program costs. This amount was recovered by the then-existing DSMAC over a twelve-month period beginning March 1, 2012. This amount did not include $10 million already being recovered in general retail base rates, but did include amortization of 2009 costs (approximately $5 million of the $72 million).

On June 1, 2012, APS filed its 2013 Demand Side Management Implementation Plan. In 2013, the standards require APS to achieve cumulative energy savings equal to 5% of its 2012 retail energy sales. Later in 2012, APS filed a supplement to its plan that included a proposed budget for 2013 of $87.6 million.

The ACC Staff recommendation and proposed order, issued on October 30, 2013, largely recommended continuing the status quo, although at lower funding levels. ACC Staff recommended approval of all existing cost-effective energy efficiency and demand response programs and a budget of $68.9 million going forward. APS expects to receive a decision from the ACC in early 2014.

On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Rules should be modified or abolished. This spring the ACC will hold a series of three workshops to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

Rate Matters. APS needs timely recovery through rates of its capital and operating expenditures to maintain its financial health. APS s retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by FERC. On June 1, 2011, APS filed a rate case with the ACC. APS and other parties to the retail rate case subsequently entered into the 2012 Settlement Agreement detailing the terms upon which the parties have agreed to settle the rate case. See Note 3 for details regarding the 2012 Settlement Agreement terms and for information on APS s FERC rates.

APS has several recovery mechanisms in place that provide more timely recovery to APS of its fuel and transmission costs, and costs associated with the promotion and implementation of its demand side management and renewable energy efforts and customer programs. These mechanisms are described more fully in Note 3.

As part of APS s acquisition of SCE s interest in Units 4 and 5 of Four Corners, APS and SCE agreed, via a Transmission Termination Agreement, that upon closing of the acquisition, the companies would terminate an existing transmission agreement (Transmission Agreement) between the parties that provides transmission capacity on a system (the Arizona Transmission System) for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an

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alternate arrangement under which SCE will assign its 1,555 MW capacity rights over the Arizona Transmission System to third-parties, including 300 MW to APS s marketing and trading group for transmission of the additional power received from Four Corners. This arrangement becomes effective upon FERC approval and will remain in effect until the net payments received by SCE in connection with the assignments reach $40 million, at which time the arrangement and the Transmission Agreement will terminate. APS believes that FERC will approve the alternate arrangement as filed but, if not approved, SCE and APS will again be subject to the terms of the Transmission Termination Agreement. APS believes that the original denial by FERC of rate recovery under the Transmission Termination Agreement constitutes the failure of a condition that relieves APS of its obligations under that agreement. If APS and SCE were unable to determine a resolution through negotiation, the Transmission Termination Agreement requires that disputes be resolved through arbitration. APS is unable to predict the outcome of this matter if it proceeds to arbitration.

On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a market basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. The ACC opened a new docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. Workshops in this docket are expected to be held in 2014.

Financial Strength and Flexibility. Pinnacle West and APS currently have ample borrowing capacity under their respective credit facilities, and may readily access these facilities ensuring adequate liquidity for each company. Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

El Dorado. The operations of El Dorado, our only other operating subsidiary, are not expected to have any material impact on our financial results, or to require any material amounts of capital, over the next three years.

Key Financial Drivers

In addition to the continuing impact of the matters described above, many factors influence our financial results and our future financial outlook, including those listed below. We closely monitor these factors to plan for the Company s current needs, and to adjust our expectations, financial budgets and forecasts appropriately.

Electric Operating Revenues. For the years 2011 through 2013, retail electric revenues comprised approximately 93% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery

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mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Customer and Sales Growth. Retail customer growth in APS s service territory in 2013 was 1.3% compared with the prior year. For the three years 2011 through 2013, APS s customer growth averaged 1.0% per year. We currently expect annual customer growth to average about 2.5% for 2014 through 2016 based on our assessment of modestly improving economic conditions, both nationally and in Arizona. Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, decreased 0.5% in 2013 compared with the prior year, reflecting the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, offset by mildly improving economic conditions and customer growth. For the three years 2011 through 2013, APS experienced annual increases in retail electricity sales averaging 0.1%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average about 1% during 2014 through 2016, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A failure of the Arizona economy to improve could further impact these estimates.

Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. Based on past experience, a reasonable range of variation in our kWh sales projection attributable to such economic factors under normal business conditions can result in increases or decreases in annual net income of up to $10 million.

Weather. In forecasting the retail sales growth numbers provided above, we assume normal weather patterns based on historical data. Historically, extreme weather variations have resulted in annual variations in net income in excess of $20 million. However, our experience indicates that the more typical variations from normal weather can result in increases or decreases in annual net income of up to $10 million.

Fuel and Purchased Power Costs. Fuel and purchased power costs included on our Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service in our market areas, changes in our generation resource allocation, our hedging program for managing such costs and PSA deferrals and the related amortization.

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, outages, renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors. In the 2009 Settlement Agreement, APS committed to operational expense reductions from 2010 through 2014, and received approval to defer certain pension and other postretirement benefit cost increases incurred in 2011 and 2012, which totaled $25 million, as a regulatory asset, until the most recent general retail rate case decision became effective on July 1, 2012. In July 2012, we began amortizing the regulatory asset over a 36-month period.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and

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distribution facilities), and changes in depreciation and amortization rates. See Capital Expenditures below for information regarding the planned additions to our facilities. See Note 1 regarding deferral of certain costs pursuant to an ACC order.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 10.5% of the assessed value for 2013, 9.6% for 2012, and 9.0% for 2011. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units, transmission and distribution facilities. (See Note 3 for property tax deferrals contained in the 2012 Settlement Agreement).

Income Taxes. Income taxes are affected by the amount of pretax book income, income tax rates, certain deductions and non-taxable items, such as AFUDC. In addition, income taxes may also be affected by the settlement of issues with taxing authorities.

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 6). The primary factors affecting borrowing levels are expected to be our capital expenditures, long-term debt maturities, equity issuances and internally generated cash flow. An allowance for borrowed funds used during construction offsets a portion of interest expense while capital projects are under construction. We stop accruing AFUDC on a project when it is placed in commercial operation.

RESULTS OF OPERATIONS

Pinnacle West s only reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results 2013 compared with 2012.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2013 was $406 million, compared with net income of $382 million for the prior year. The results reflect an increase of approximately $21 million for the regulated electricity segment, primarily due to increases related to the retail regulatory settlement effective July 1, 2012 (see Note 3); higher retail transmission revenues; and lower net interest charges due to lower debt balances and lower interest rates in the current-year period. These positive factors were partially offset by higher operations and maintenance expenses; higher fuel and purchased power costs, net of related deferrals; lower retail sales as a result of changes in customer usage related to energy efficiency, customer conservation and distributed generation, partially offset by customer growth; and higher depreciation and amortization expenses.

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The following table presents net income attributable to common shareholders by business segment compared with the prior year:

	Year Ended December 31, 2013	2012	Net Change
		(dollars in millions)	
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 2,356	$ 2,299	$ 57
Operations and maintenance	(925)	(885)	(40)
Depreciation and amortization	(416)	(404)	(12)
Taxes other than income taxes	(164)	(159)	(5)
Other income (expenses), net	11	6	5
Interest charges, net of allowance for borrowed funds used during construction	(187)	(200)	13
Income taxes	(232)	(237)	5
Less income related to noncontrolling interests (Note 19)	(34)	(32)	(2)
Regulated electricity segment net income	409	388	21
All other	(3)		(3)
Income from Continuing Operations Attributable to Common Shareholders	406	388	18
Loss from Discontinued Operations Attributable to Common Shareholders (a)		(6)	6
Net Income Attributable to Common Shareholders	$ 406	$ 382	$ 24

(a) Includes activities related to SunCor.

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $57 million higher for the year ended December 31, 2013 compared with the prior year. The following table summarizes the major components of this change:

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	Operating revenues	Increase (Decrease) Fuel and purchased power expenses (dollars in millions)	Net change
Impacts of retail regulatory settlement effective July 1, 2012	$ 64	$ 6	$ 58
Higher demand-side management, renewable energy and similar regulatory surcharges	34	7	27
Higher retail transmission revenues	11		11
Lower retail sales due to changes in customer usage patterns and related pricing, partially offset by customer growth	(17)	(4)	(13)
Higher fuel and purchased power costs, net of related deferrals and off-system sales	74	95	(21)
Miscellaneous items, net	(8)	(3)	(5)
Total	$ 158	$ 101	$ 57

Operations and maintenance. Operations and maintenance expenses increased $40 million for the year ended December 31, 2013 compared with the prior year primarily because of:

- An increase of $14 million related to technical analysis, consulting, advertising and communications costs;
- An increase of $13 million related to costs for demand-side management, renewable energy and similar regulatory programs, which were largely offset in operating revenues;
- An increase of $9 million related to the closure of Four Corners Units 1, 2, and 3, deferred for regulatory recovery in depreciation;
- An increase of $6 million in energy delivery and customer service costs;
- An increase of $6 million in information technology costs;
- A decrease of $6 million in generation costs primarily related to lower fossil generation outage costs and lower nuclear generation costs; and

- A decrease of $2 million related to other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $12 million higher for the year ended December 31, 2013 compared with the prior year, primarily because of

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increased plant in service, partially offset by the regulatory deferral of operating expenses associated with the closure of Four Corners Units 1, 2, and 3.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, decreased $13 million for the year ended December 31, 2013 compared with the prior year, primarily because of lower debt balances and lower interest rates in the current year.

Income taxes. Income taxes were $5 million lower for the year ended December 31, 2013 compared with the prior year primarily due to a lower effective tax rate in the current period, partially offset by the effects of higher pretax income in the current year.

Operating Results 2012 compared with 2011.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2012 was $382 million, compared with net income of $339 million for the prior year. The results reflect an increase of approximately $59 million for the regulated electricity segment, primarily due to increases related to the retail regulatory settlement effective July 1, 2012 (see Note 3); higher retail transmission revenues, lower depreciation and amortization due to 20-year Palo Verde license extensions received in 2011; and lower net interest charges due to lower debt balances and lower interest rates in the current year.

The $17 million decrease in discontinued operations is primarily related to a contribution Pinnacle West made to SunCor s estate as part of a negotiated resolution to the bankruptcy (see Note 1) and absence of the 2011 gain on sale of our investment in APSES.

The following table presents net income attributable to common shareholders by business segment compared with the prior year:

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	Year Ended December 31, 2012	2011	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses (a)	$ 2,299	$ 2,228	$ 71
Operations and maintenance (a)	(885)	(904)	19
Depreciation and amortization	(404)	(427)	23
Taxes other than income taxes	(159)	(148)	(11)
Other income (expenses), net	6	16	(10)
Interest charges, net of allowance for borrowed funds used during construction	(200)	(224)	24
Income taxes	(237)	(184)	(53)
Less income related to noncontrolling interests (Note 19)	(32)	(28)	(4)
Regulated electricity segment net income	388	329	59
All other		(1)	1
Income from Continuing Operations Attributable to Common Shareholders	388	328	60
Income (Loss) from Discontinued Operations Attributable to Common Shareholders (b)	(6)	11	(17)
Net Income Attributable to Common Shareholders	$ 382	$ 339	$ 43

(a) Includes effects of 2011 settlement of certain transmission right-of-way costs, which did not affect net income, but increased both electric operating revenues and operations and maintenance expenses by $28 million. Costs related to the settlement were offset by related revenues from SCE, which leases the related transmission line from APS.

(b) Includes activities related to APSES and SunCor.

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $71 million higher for the year ended December 31, 2012 compared with the prior year. The following table summarizes the major components of this change:

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	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Impacts of retail regulatory settlement effective July 1, 2012	$ 64	$ 1	$ 63
Higher retail transmission revenues	41		41
Lower fuel and purchased power costs, net of related deferrals and off-system sales	(11)	(14)	3
Lower demand-side management, renewable energy and similar regulatory surcharges	(3)	4	(7)
Settlement in 2011 of certain prior-period transmission right-of-way revenues	(28)		(28)
Miscellaneous items, net	(7)	(6)	(1)
Total	$ 56	$ (15)	$ 71

Operations and maintenance. Operations and maintenance expenses decreased $19 million for the year ended December 31, 2012 compared with the prior year primarily because of:

- A decrease of $28 million related to settlement in 2011 of certain transmission right-of-way costs, which was offset in operating revenues;
- A decrease of $22 million related to costs for demand-side management, renewable energy and similar regulatory programs;
- A decrease of $15 million in generation costs, primarily related to lower nuclear generation costs;
- An increase of $21 million related to employee benefit costs, including approximately $12 million of pension and other postretirement costs;
- An increase of $9 million related to higher stock compensation costs resulting from an improved company stock price and estimated performance results;
- An increase of $7 million in information technology costs, primarily related to higher software maintenance; and

- An increase of $9 million due to other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $23 million lower for the year ended December 31, 2012 compared with the prior year, primarily due to the impacts of Palo Verde operating license extensions, partially offset by increased plant in service.

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Taxes other than income taxes. Taxes other than income taxes increased $11 million for the year ended December 31, 2012 compared with the prior year, primarily because of higher property tax rates in the current year.

Other income (expenses), net. Other income (expenses), net, decreased $10 million for the year ended December 31, 2012 compared with the prior year, primarily because of higher investment losses of approximately $2 million and other non-operating expenses of approximately $8 million in the current year.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, decreased $24 million for the year ended December 31, 2012 compared with the prior year, primarily because of lower debt balances and lower interest rates in the current year.

Income taxes. Income taxes were $53 million higher for the year ended December 31, 2012 compared with the prior year, primarily due to higher pre-tax income in the current year and a lower effective tax rate in 2011.

Discontinued Operations

Results from discontinued operations decreased $17 million, primarily due to a contribution Pinnacle West made to SunCor s estate as part of a negotiated resolution to the bankruptcy (see Note 1) and absence of a gain related to the sale of our investment in APSES in 2011.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Pinnacle West s primary cash needs are for dividends to our shareholders and principal and interest payments on our indebtedness. The level of our common stock dividends and future dividend growth will be dependent on declaration by our Board of Directors and based on a number of factors, including our financial condition, payout ratio, free cash flow and other factors.

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2013, APS s common equity ratio, as defined, was 58%. Its total shareholder equity was approximately $4.3 billion, and total capitalization was approximately $7.5 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.0 billion, assuming APS s total capitalization remains the same. This restriction does not materially affect Pinnacle West s ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

APS s capital requirements consist primarily of capital expenditures and maturities of long-term debt. APS funds its capital requirements with cash from operations and, to the extent necessary, external debt financing and equity infusions from Pinnacle West.

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Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the years ended December 31, 2013, 2012 and 2011 (dollars in millions):

Pinnacle West Consolidated

	2013	2012	2011
Net cash flow provided by operating activities	$ 1,153	$ 1,171	$ 1,125
Net cash flow used for investing activities	(1,009)	(873)	(782)
Net cash flow used for financing activities	(161)	(305)	(420)
Net decrease in cash and cash equivalents	$ (17)	$ (7)	$ (77)

Arizona Public Service Company

	2013	2012	2011
Net cash flow provided by operating activities	$ 1,194	$ 1,176	$ 1,128
Net cash flow used for investing activities	(1,009)	(873)	(834)
Net cash flow used for financing activities	(185)	(319)	(374)
Net decrease in cash and cash equivalents	$	$ (16)	$ (80)

Operating Cash Flows

2013 Compared with 2012. Pinnacle West s consolidated net cash provided by operating activities was $1,153 million in 2013, compared to $1,171 million in 2012, a decrease of $18 million in net cash provided. The decrease is primarily related to a $127 million change in cash collateral posted and $76 million of higher pension contributions made in 2013 compared to 2012 (approximately $18 million of which is reflected in capital expenditures). The decrease is partially offset by approximately $167 million of higher cash inflows primarily due to higher authorized revenue requirements resulting from the retail regulatory settlement effective July 1, 2012 and other changes in working capital.

2012 Compared with 2011. Pinnacle West s consolidated net cash provided by operating activities was $1,171 million in 2012, compared to $1,125 million in 2011, an increase of $46 million in net cash provided. The increase is primarily related to a $77 million reduction of cash collateral posted and a decrease of $23 million in cash paid for interest in the current year, partially offset by a $26 million increase in property tax payments, a $65 million pension contribution in 2012 (approximately $12 million of which is reflected in capital expenditures) and other changes in working capital.

Other. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 (ERISA) require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 107% funded as of January 1, 2013 and is estimated to be approximately 103% funded as of January 1, 2014. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $141 million in 2013, $65 million in 2012, and zero in 2011. The minimum contributions for the pension plan total $141 million for the next three years under the recently enacted Moving Ahead

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for Progress in the 21st Century Act (zero in 2014, $19 million in 2015 and $122 million in 2016). Instead, we expect to make voluntary contributions totaling $300 million for the next three years ($175 million in 2014, of which $70 million was already contributed in early 2014, up to $100 million in 2015, and up to $25 million in 2016). With regard to contributions to our other postretirement benefit plans, we made a contribution of approximately $14 million in 2013, $23 million in 2012, and $19 million in 2011. The contributions to our other postretirement benefit plans for 2014, 2015 and 2016 are expected to be approximately $10 million each year.

The $70 million long-term income tax receivable on the Consolidated Balance Sheets as of December 31, 2012 represented the anticipated refund related to an APS tax accounting method change approved by the Internal Revenue Service (IRS) in the third quarter of 2009. On July 9, 2013, IRS guidance was released which provided clarification regarding the timing and amount of this cash receipt. As a result of this guidance, uncertain tax positions decreased $67 million during the third quarter. This decrease in uncertain tax positions resulted in a corresponding increase to the total anticipated refund due from the IRS and an offsetting increase in long-term deferred tax liabilities. Additionally, as a result of this IRS guidance, the resulting $137 million anticipated refund was reclassified to current income tax receivable.

During the year ended December 31, 2013, the IRS finalized the examination of tax returns for the years ended December 31, 2008 and 2009, and the $137 million anticipated refund was reduced by approximately $4 million to reflect the outcome of this examination. On December 17, 2013, the Joint Committee on Taxation approved the anticipated refund. Cash related to this refund was received in the first quarter of 2014.

Investing Cash Flows

2013 Compared with 2012. Pinnacle West s consolidated net cash used for investing activities was $1,009 million in 2013, compared to $873 million in 2012, an increase of $136 million in net cash used. The increase in net cash used for investing activities is primarily related to APS s purchase of SCE s interest in Units 4 and 5 of Four Corners of approximately $209 million, partially offset by a decrease of approximately $73 million in other capital expenditures.

2012 Compared with 2011. Pinnacle West s consolidated net cash used for investing activities was $873 million in 2012, compared to $782 million in 2011, an increase of $91 million in net cash used. The increase in net cash used for investing activities is primarily due to the absence of $55 million in proceeds from the sale of life insurance policies in 2011 and the absence of $45 million in proceeds from the sale of Pinnacle West s investment in APSES in 2011.

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Capital Expenditures. The following table summarizes the estimated capital expenditures for the next three years:

Capital Expenditures

(dollars in millions)

	Estimated for the Year Ended December 31, 2014	2015	2016
APS			
Generation:			
Nuclear Fuel	$ 80	$ 86	$ 88
Renewables	118	7	
Environmental	30	57	213
Other Generation	230	248	355
Distribution	255	374	363
Transmission	198	213	196
Other (a)	54	41	48
Total APS	$ 965	$ 1,026	$ 1,263

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS s existing fossil and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. The estimated Renewables expenditures include 20 MW of utility-scale solar projects which were approved by the ACC in the 2014 RES Implementation Plan. We have not included estimated costs for Cholla s compliance with MATS or EPA s regional haze rule since we have challenged the regional haze rule judicially and are considering our future options with respect to that plant if the regional haze rule is upheld. The portion of estimated costs through 2016 for installation of pollution control equipment needed to ensure Four Corners compliance with EPA s regional haze rules have been included in the table above. We are monitoring the status of other environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

Distribution and transmission capital expenditures are comprised of infrastructure additions and upgrades, capital replacements, and new customer construction. Examples of the types of projects included in the forecast include power lines, substations, and line extensions to new residential and commercial developments.

Capital expenditures will be funded with internally generated cash and external financings, which may include issuances of long-term debt and Pinnacle West common stock.

Financing Cash Flows and Liquidity

2013 Compared with 2012. Pinnacle West s consolidated net cash used for financing activities was $161 million in 2013, compared to $305 million of net cash used in 2012, a decrease of $144 million in net cash used. The decrease in net cash used for financing activities is primarily due to $531 million in lower repayments of long-term debt, largely offset by $340 million in lower issuances of long-term debt and a $31 million net change in APS s commercial paper borrowings, which is classified as short-term borrowings on the Consolidated Balance Sheets. On December 30, 2013, commercial paper issuances were used to fund the acquisition of SCE s 48% ownership interest in each of Units 4 and 5 of Four Corners (see below).

2012 Compared with 2011. Pinnacle West s consolidated net cash used for financing activities was $305 million in 2012, compared to $420 million in 2011, a decrease of $115 million in net cash used. The decrease in net cash used for financing activities is primarily due to an increase of $92 million in APS s short-term debt borrowings in 2012. In addition, APS had $56 million in higher issuances of long-term debt, partially offset by $99 million in higher repayments of long-term debt. Pinnacle West had $100 million in lower repayments of long-term debt, partially offset by $50 million in lower debt issuances (see below).

Significant Financing Activities. On December 18, 2013, the Pinnacle West Board of Directors declared a quarterly dividend of $0.5675 per share of common stock, payable on March 3, 2014, to shareholders of record on February 3, 2014. During 2013, Pinnacle West increased its indicated annual dividend from $2.18 per share to $2.27 per share. For the year ended December 31, 2013, Pinnacle West s total dividends paid per share of common stock were $2.20 per share, which resulted in dividend payments of $235 million.

On March 22, 2013, APS issued an additional $100 million par amount of its outstanding 4.50% unsecured senior notes that mature on April 1, 2042. The net proceeds from the sale were used to repay short-term commercial paper borrowings and replenish cash used to redeem certain tax-exempt indebtedness in November 2012.

On May 1, 2013, APS purchased all $32 million of the Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series C, due 2029. On May 28, 2013, we remarketed the bonds. The interest rate for these bonds was set to a new term rate. The new term rate for these bonds ends, subject to a mandatory tender, on May 30, 2018. During this time, the bonds will bear interest at a rate of 1.75% per annum. These bonds are classified as long-term debt on our Consolidated Balance Sheets at December 31, 2013 and were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2012.

On July 12, 2013, APS purchased all $33 million of the Coconino County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 1994 Series A, due 2029. On January 15, 2014, these bonds were canceled. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2012.

On October 11, 2013, APS purchased all $32 million of the City of Farmington, New Mexico Pollution Control Revenue Bonds, 1994 Series C, due 2024. On January 15, 2014, these bonds were canceled. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2012.

On January 10, 2014, APS issued $250 million of 4.70% unsecured senior notes that mature on January 15, 2044. The proceeds from the sale were used to repay commercial paper which was used to fund the purchase price and costs associated with the acquisition of SCE s 48% ownership interest in

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each of Units 4 and 5 of Four Corners and to replenish cash used to re-acquire two series of tax-exempt indebtedness.

Available Credit Facilities. Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs.

At December 31, 2013, Pinnacle West s $200 million credit facility, which matures in November 2016, was available to refinance indebtedness of the Company and for other general corporate purposes, including credit support for its $200 million commercial paper program. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2013, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding, and no commercial paper borrowings.

On April 9, 2013, APS refinanced its $500 million revolving credit facility that would have matured in February 2015, with a new $500 million facility. The new revolving credit facility matures in April 2018.

At December 31, 2013, APS had two credit facilities totaling $1 billion, including a $500 million credit facility that was refinanced in April 2013 (see above) and a $500 million credit facility that matures in November 2016. APS may increase the amount of each facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS can use these facilities to refinance indebtedness and for other general corporate purposes. Interest rates are based on APS s senior unsecured debt credit ratings.

The facilities described above are available to support APS s $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2013, APS had no outstanding borrowings or letters of credit under its revolving credit facilities. APS had commercial paper borrowings of $153 million at December 31, 2013.

See Financial Assurances in Note 11 for a discussion of APS s separate outstanding letters of credit.

Other Financing Matters. See Note 3 for information regarding the PSA approved by the ACC.

See Note 3 for information regarding the settlement related to the 2008 retail rate case, which includes ACC authorization and requirements of equity infusions into APS.

See Note 17 for information related to the change in our margin and collateral accounts.

Debt Provisions

Pinnacle West s and APS s debt covenants related to their respective bank financing arrangements include maximum debt to capitalization ratios. Pinnacle West and APS comply with this covenant. For both Pinnacle West and APS, this covenant requires that the ratio of consolidated debt to total consolidated capitalization not exceed 65%. At December 31, 2013, the ratio was approximately 47% for Pinnacle West and 45% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt

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subject to the covenants and could cross-default other debt. See further discussion of cross-default provisions below.

Neither Pinnacle West s nor APS s financing agreements contain rating triggers that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of Pinnacle West s loan agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under certain other material agreements. All of APS s bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under certain other material agreements. Pinnacle West and APS do not have a material adverse change restriction for credit facility borrowings.

See Note 6 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 14, 2014 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West s or APS s securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

	Moody s	**Standard & Poor s**	**Fitch**
Pinnacle West			
Corporate credit rating	Baa1	A-	BBB+
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	A3	A-	BBB+
Senior unsecured	A3	A-	A-
Secured lease obligation bonds	A3	A-	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable

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Off-Balance Sheet Arrangements

See Note 19 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

Contractual Obligations

The following table summarizes Pinnacle West s consolidated contractual requirements as of December 31, 2013 (dollars in millions):

	2014	2015-2016	2017-2018	Thereafter	Total
Long-term debt payments, including interest: (a)					
APS	$ 710	$ 986	$ 270	$ 3,374	$ 5,340
Pinnacle West	2	127			129
Total long-term debt payments, including interest	712	1,113	270	3,374	5,469
Short-term debt payments, including interest (b)	153				153
Fuel and purchased power commitments (c)	644	1,229	1,154	8,471	11,498
Renewable energy credits (d)	48	84	84	453	669
Purchase obligations (e)	85	37	39	246	407
Coal reclamation	1	9	28	170	208
Nuclear decommissioning funding requirements	17	19	4	66	106
Noncontrolling interests (f)	20	35			55
Operating lease payments	20	23	9	59	111
Total contractual commitments	$ 1,700	$ 2,549	$ 1,588	$ 12,839	$ 18,676

(a) The long-term debt matures at various dates through 2042 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2013 (see Note 6).

(b) The short-term debt represents commercial paper borrowings at APS (see Note 5).

(c) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation (see Notes 3 and 11). These amounts include commitments incurred from acquiring SCE s interest in Four Corners.

(d) Contracts to purchase renewable energy credits in compliance with the RES (see Note 3).

(e) These contractual obligations include commitments for capital expenditures and other obligations.

(f) Payments to the noncontrolling interests relate to the Palo Verde Sale Leaseback (see Note 19). We have committed to retain the assets relating to the noncontrolling interests beyond 2015, either through lease extensions or by purchasing the assets. If we elect to purchase the assets, the purchase price will be based on the fair value of the assets at the end of 2015. Such value is unknown at this time and is subject to an appraisal process.

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If we elect to extend the leases, we will be required to make annual payments beginning in 2016 of approximately $23 million; however, the length of the lease extensions is unknown at this time as it must be determined through an appraisal process. Due to these uncertainties, amounts relating to the noncontrolling interests beyond 2015 have not been included in the table above.

This table excludes $42 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. This table also excludes approximately zero, $19 million and $122 million in estimated minimum pension contributions for 2014, 2015 and 2016, respectively (see Note 8).

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP), management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of the uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense 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. Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $809 million of regulatory assets and $901 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2013.

Included in the balance of regulatory assets at December 31, 2013 is a regulatory asset of $314 million for pension and other postretirement benefits. This regulatory asset represents the future recovery of these costs through retail rates as these amounts are charged to earnings. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future earnings.

See Notes 1 and 3 for more information.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, the expected long-term rate of return on plan assets used to estimate earnings on invested funds

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over the long-term, and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2013 reported pension liability on the Consolidated Balance Sheets and our 2013 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West s Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Pension Liability**	**Impact on Pension Expense**
Discount rate:		
Increase 1%	$ (280)	$ (14)
Decrease 1%	337	16
Expected long-term rate of return on plan assets:		
Increase 1%		(10)
Decrease 1%		10

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2013 reported other postretirement benefit obligation on the Consolidated Balance Sheets and our 2013 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West s Consolidated Statements of Income (dollars in millions):

	Increase (Decrease)	
Actuarial Assumption (a)	**Impact on Other Postretirement Benefit Obligation**	**Impact on Other Postretirement Benefit Expense**
Discount rate:		
Increase 1%	$ (120)	$ (7)
Decrease 1%	151	9
Healthcare cost trend rate (b):		
Increase 1%	149	13
Decrease 1%	(120)	(10)
Expected long-term rate of return on plan assets pretax:		
Increase 1%		(3)
Decrease 1%		3

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(a) Each fluctuation assumes that the other assumptions of the calculation are held constant while the rates are changed by one percentage point.

(b) This assumes a 1% change in the initial and ultimate healthcare cost trend rate.

See Note 8 for further details about our pension and other postretirement benefit plans.

Fair Value Measurements

We account for derivative instruments, investments held in our nuclear decommissioning trust fund, certain cash equivalents and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We use inputs, or assumptions that market participants would use, to determine fair market value. The significance of a particular input determines how the instrument is classified in a fair value hierarchy. We utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of fair value sometimes requires subjective and complex judgment. Our assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within a fair value hierarchy. Actual results could differ from our estimates of fair value. See Note 1 for a discussion on accounting policies and Note 14 for further fair value measurement discussion.

OTHER ACCOUNTING MATTERS

During 2013, we adopted new accounting guidance relating to balance sheet offsetting disclosures, and disclosures of amounts reclassified from accumulated OCI. During the first quarter of 2014 we are required to adopt new accounting guidance related to balance sheet presentation of certain unrecognized tax benefits. See Note 2.

MARKET AND CREDIT RISKS

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by our nuclear decommissioning trust fund and benefit plan assets.

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 14 and Note 20) and benefit plan assets. The nuclear decommissioning trust fund and benefit plan assets also have risks associated with the changing market value of their equity and other non-fixed income investments. Nuclear decommissioning and benefit plan costs are recovered in regulated electricity prices.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2013 and

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2012. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2013 and 2012 (dollars in thousands):

Pinnacle West Consolidated

2013	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2014	0.23%	$ 153,125		$	5.58%	$ 540,424
2015			1.02%	157,000	4.79%	313,420
2016			0.06%	43,580	6.15%	314,000
2017						
2018					1.75%	32,000
Years thereafter					6.12%	1,940,150
Total		$ 153,125		$ 200,580		$ 3,139,994
Fair value		$ 153,125		$ 200,580		$ 3,378,102

2012	Short-Term Debt Interest Rates	Short-Term Debt Amount	Variable-Rate Long-Term Debt Interest Rates	Variable-Rate Long-Term Debt Amount	Fixed-Rate Long-Term Debt Interest Rates	Fixed-Rate Long-Term Debt Amount
2013	0.38%	$ 92,175		$	4.94%	$ 122,828
2014					5.58%	540,424
2015			1.07%	157,000	4.79%	313,420
2016			0.15%	43,580	6.15%	314,000
2017						
Years thereafter					6.21%	1,840,150
Total		$ 92,175		$ 200,580		$ 3,130,822
Fair value		$ 92,175		$ 200,268		$ 3,674,958

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The tables below present contractual balances of APS s long-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2013 and 2012. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2013 and 2012 (dollars in thousands):

APS Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2013	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2014	0.23%	$ 153,125		$	5.58%	$ 540,424
2015			0.03%	32,000	4.79%	313,420
2016			0.06%	43,580	6.15%	314,000
2017						
2018					1.75%	32,000
Years thereafter					6.12%	1,940,150
Total		$ 153,125		$ 75,580		$ 3,139,994
Fair value		$ 153,125		$ 75,580		$ 3,378,102

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2012	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2013	0.38%	$ 92,175		$	4.94%	$ 122,828
2014					5.58%	540,424
2015			0.13%	32,000	4.79%	313,420
2016			0.15%	43,580	6.15%	314,000
2017						
Years thereafter					6.21%	1,840,150
Total		$ 92,175		$ 75,580		$ 3,130,822
Fair value		$ 92,175		$ 75,580		$ 3,674,958

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity and natural gas. Our risk management committee, consisting of officers and key management personnel, oversees company-wide energy risk management activities to ensure compliance with our stated energy risk management policies. We manage risks associated with these market fluctuations by utilizing various commodity instruments that may qualify as derivatives, including futures, forwards, options and swaps. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities.

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The following table shows the net pretax changes in mark-to-market of our derivative positions in 2013 and 2012 (dollars in millions):

	2013	2012
Mark-to-market of net positions at beginning of year	$ (122)	$ (222)
Recognized in earnings (a):		
Change in mark-to-market gains (losses) for future period deliveries	(1)	1
Decrease in regulatory asset	6	37
Recognized in OCI:		
Change in mark-to-market losses for future period deliveries (b)		(37)
Mark-to-market losses realized during the period	44	99
Change in valuation techniques		
Mark-to-market of net positions at end of year	$ (73)	$ (122)

(a) Represents the amounts reflected in income after the effect of PSA deferrals.

(b) The changes in mark-to-market recorded in OCI are due primarily to changes in forward natural gas prices.

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2013 by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, Derivative Accounting and Fair Value Measurements, for more discussion of our valuation methods.

Source of Fair Value	2014	2015	2016	2017	2018	Years thereafter	Total fair value
Observable prices provided by other external sources	$ (15)	$ (6)	$ (3)	$	$	$	$ (24)
Prices based on unobservable inputs	(11)	(12)	(12)	(5)	(4)	(5)	(49)
Total by maturity	$ (26)	$ (18)	$ (15)	$ (5)	$ (4)	$ (5)	$ (73)

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The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management assets and liabilities included on Pinnacle West s Consolidated Balance Sheets at December 31, 2013 and 2012 (dollars in millions):

	December 31, 2013 Gain (Loss)		December 31, 2012 Gain (Loss)	
	Price Up 10%	**Price Down 10%**	**Price Up 10%**	**Price Down 10%**
Mark-to-market changes reported in:				
Earnings (a)				
Natural gas	$	$	$	$
Regulatory asset (liability) or OCI (b)				
Electricity	6	(6)	7	(7)
Natural gas	26	(26)	25	(25)
Total	$ 32	$ (32)	$ 32	$ (32)

(a) Represents the amounts reflected in income after the effect of PSA deferrals.

(b) These contracts are economic hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged. To the extent the amounts are eligible for inclusion in the PSA, the amounts are recorded as either a regulatory asset or liability.

Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 17 for a discussion of our credit valuation adjustment policy.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Market and Credit Risks in Item 7 above for a discussion of quantitative and qualitative disclosures about market risk.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND

FINANCIAL STATEMENT SCHEDULES

See Note 13 and S-2 for the selected quarterly financial data (unaudited) required to be presented in this Item.

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MANAGEMENT S REPORT ON INTERNAL CONTROL

OVER FINANCIAL REPORTING

(PINNACLE WEST CAPITAL CORPORATION)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f), for Pinnacle West. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control Integrated Framework (1992),* our management concluded that our internal control over financial reporting was effective as of December 31, 2013. The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and also relates to the Company s consolidated financial statements.

February 21, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Pinnacle West Capital Corporation

Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the Company) as of December 31, 2013 and 2012 and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedules listed in the Index at Item 15. We also have audited the Company s 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. The Company s management is responsible for these financial statements and financial statement schedules, 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 an opinion on these financial statements and financial statement schedules and an opinion on the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement 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, 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 by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

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Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries as of December 31, 2013 and 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. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 21, 2014

PINNACLE WEST CAPITAL CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(dollars and shares in thousands, except per share amounts)

	Year Ended December 31, 2013	2012	2011
OPERATING REVENUES	$ 3,454,628	$ 3,301,804	$ 3,241,379
OPERATING EXPENSES			
Fuel and purchased power	1,095,709	994,790	1,009,464
Operations and maintenance	924,727	884,769	904,286
Depreciation and amortization	415,708	404,336	427,054
Taxes other than income taxes	164,167	159,323	147,408
Other expenses	7,994	6,831	6,659
Total	2,608,305	2,450,049	2,494,871
OPERATING INCOME	846,323	851,755	746,508
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	25,581	22,436	23,707
Other income (Note 18)	1,704	1,606	3,111
Other expense (Note 18)	(16,024)	(19,842)	(10,451)
Total	11,261	4,200	16,367
INTEREST EXPENSE			
Interest charges	201,888	214,616	241,995
Allowance for borrowed funds used during construction (Note 1)	(14,861)	(14,971)	(18,358)
Total	187,027	199,645	223,637
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	670,557	656,310	539,238
INCOME TAXES (Note 4)	230,591	237,317	183,604
INCOME FROM CONTINUING OPERATIONS	439,966	418,993	355,634
INCOME (LOSS) FROM DISCONTINUED OPERATIONS			
Net of income tax expense (benefit) of $, $(3,813) and $7,418 (Note 1)		(5,829)	11,306
NET INCOME	439,966	413,164	366,940
Less: Net income attributable to noncontrolling interests (Note 19)	33,892	31,622	27,467
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 406,074	$ 381,542	$ 339,473
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING BASIC	109,984	109,510	109,053
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING DILUTED	110,806	110,527	109,864
EARNINGS PER WEIGHTED AVERAGE COMMON SHARE OUTSTANDING			
Income from continuing operations attributable to common shareholders basic	$ 3.69	$ 3.54	$ 3.01
Net income attributable to common shareholders basic	3.69	3.48	3.11
Income from continuing operations attributable to common shareholders diluted	3.66	3.50	2.99
Net income attributable to common shareholders diluted	3.66	3.45	3.09

AMOUNTS ATTRIBUTABLE TO COMMON SHAREHOLDERS:						
Income from continuing operations, net of tax	$	406,074	$	387,380	$	328,110
Discontinued operations, net of tax				(5,838)		11,363
Net income attributable to common shareholders	$	406,074	$	381,542	$	339,473

See Notes to Pinnacle West s Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(dollars in thousands)

	Year Ended December 31, 2013	2012	2011
NET INCOME	$ 439,966	$ 413,164	$ 366,940
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit of $140, $14,900, and $37,389 (Note 17)	(213)	(22,763)	(57,271)
Reclassification of net realized loss, net of tax benefit of $17,472, $39,120, and $46,288 (Note 17)	26,747	59,887	70,902
Pension and other postretirement benefits activity, net of tax (expense) benefit of $(6,156), $(651), and $3,935 (Note 8)	9,421	1,031	(6,026)
Total other comprehensive income	35,955	38,155	7,605
COMPREHENSIVE INCOME	475,921	451,319	374,545
Less: Comprehensive income attributable to noncontrolling interests	33,892	31,622	27,467
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 442,029	$ 419,697	$ 347,078

See Notes to Pinnacle West s Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION

CONSOLIDATED BALANCE SHEETS

(dollars in thousands)

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9,526	$ 26,202
Customer and other receivables	299,904	277,225
Accrued unbilled revenues	96,796	94,845
Allowance for doubtful accounts	(3,203)	(3,340)
Materials and supplies (at average cost)	221,682	218,096
Fossil fuel (at average cost)	38,028	31,334
Deferred income taxes (Note 4)	91,152	152,191
Income tax receivable (Note 4)	135,517	2,423
Assets from risk management activities (Note 17)	17,169	25,699
Deferred fuel and purchased power regulatory asset (Note 3)	20,755	72,692
Other regulatory assets (Note 3)	76,388	71,257
Other current assets	39,895	37,102
Total current assets	1,043,609	1,005,726
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 17)	23,815	35,891
Nuclear decommissioning trust (Notes 14 and 20)	642,007	570,625
Other assets	60,875	62,694
Total investments and other assets	726,697	669,210
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 10)		
Plant in service and held for future use	15,200,464	14,346,367
Accumulated depreciation and amortization	(5,300,219)	(4,929,613)
Net	9,900,245	9,416,754
Construction work in progress	581,369	565,716
Palo Verde sale leaseback, net of accumulated depreciation of $225,925 and $222,055 (Note 19)	125,125	128,995
Intangible assets, net of accumulated amortization of $439,703 and $411,543	157,689	162,150
Nuclear fuel, net of accumulated amortization of $146,057 and $133,950	124,557	122,778
Total property, plant and equipment	10,888,985	10,396,393
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	711,712	1,099,900
Income tax receivable (Note 4)		70,389
Other	137,683	137,997
Total deferred debits	849,395	1,308,286
TOTAL ASSETS	$ 13,508,686	$ 13,379,615

See Notes to Pinnacle West s Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION

CONSOLIDATED BALANCE SHEETS

(dollars in thousands)

	December 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 284,516	$ 221,312
Accrued taxes (Note 4)	130,998	124,939
Accrued interest	48,351	49,380
Common dividends payable	62,528	59,789
Short-term borrowings (Note 5)	153,125	92,175
Current maturities of long-term debt (Note 6)	540,424	122,828
Customer deposits	76,101	79,689
Liabilities from risk management activities (Note 17)	31,892	73,741
Liability for asset retirements (Note 12)	32,896	
Regulatory liabilities (Note 3)	99,273	88,116
Other current liabilities	158,540	171,573
Total current liabilities	1,618,644	1,083,542
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	2,796,465	3,199,088
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,351,882	2,151,371
Regulatory liabilities (Notes 1, 3 and 4)	801,297	759,201
Liability for asset retirements (Note 12)	313,833	357,097
Liabilities for pension and other postretirement benefits (Note 8)	513,628	1,058,755
Liabilities from risk management activities (Note 17)	70,315	85,264
Customer advances	114,480	109,359
Coal mine reclamation	207,453	118,860
Deferred investment tax credit	152,361	99,819
Unrecognized tax benefits (Note 4)	42,209	71,135
Other	185,659	183,835
Total deferred credits and other	4,753,117	4,994,696
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY (Note 7)		
Common stock, no par value; authorized 150,000,000 shares, issued 110,280,703 at end of 2013 and 109,837,957 at end of 2012	2,491,558	2,466,923
Treasury stock at cost; 98,944 shares at end of 2013 and 95,192 shares at end of 2012	(4,308)	(4,211)
Total common stock	2,487,250	2,462,712
Retained earnings	1,785,273	1,624,102
Accumulated other comprehensive loss:		
Pension and other postretirement benefits (Note 8)	(54,995)	(64,416)
Derivative instruments (Note 17)	(23,058)	(49,592)
Total accumulated other comprehensive loss	(78,053)	(114,008)
Total shareholders equity	4,194,470	3,972,806
Noncontrolling interests (Note 19)	145,990	129,483
Total equity	4,340,460	4,102,289

TOTAL LIABILITIES AND EQUITY	$	13,508,686	$	13,379,615

See Notes to Pinnacle West s Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(dollars in thousands)

	Year Ended December 31, 2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 439,966	$ 413,164	$ 366,940
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of energy-related products and services business			(10,404)
Depreciation and amortization including nuclear fuel	492,322	481,262	493,784
Deferred fuel and purchased power	21,678	71,573	69,166
Deferred fuel and purchased power amortization	31,190	(116,716)	(155,157)
Allowance for equity funds used during construction	(25,581)	(22,436)	(23,707)
Deferred income taxes	249,296	187,023	117,952
Deferred investment tax credit	52,542	41,579	58,240
Change in derivative instruments fair value	534	(749)	4,064
Changes in current assets and liabilities:			
Customer and other receivables	(44,991)	14,587	40,626
Accrued unbilled revenues	(1,951)	30,394	(21,947)
Materials, supplies and fossil fuel	(11,878)	(23,043)	(23,398)
Income tax receivable	(133,094)	(4,043)	3,983
Other current assets	(17,913)	(27,352)	(3,079)
Accounts payable	45,414	(96,600)	58,346
Accrued taxes	6,059	12,736	8,085
Other current liabilities	(7,513)	23,869	20,358
Change in margin and collateral accounts assets	993	2,216	33,349
Change in margin and collateral accounts liabilities	12,355	137,785	29,731
Change in long-term income tax receivable	137,270	(1,756)	(3,530)
Change in unrecognized tax benefits	(91,425)	(2,583)	8,410
Change in other regulatory liabilities	64,473	13,539	37,009
Change in other long-term assets	(41,757)	6,872	(41,722)
Change in other long-term liabilities	(24,682)	29,801	58,484
Net cash flow provided by operating activities	1,153,307	1,171,122	1,125,583
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,016,322)	(889,551)	(884,350)
Contributions in aid of construction	41,090	49,876	38,096
Allowance for borrowed funds used during construction	(14,861)	(14,971)	(18,358)
Proceeds from sale of energy-related products and services business			45,111
Proceeds from nuclear decommissioning trust sales	446,025	417,603	497,780
Investment in nuclear decommissioning trust	(463,274)	(434,852)	(513,799)
Proceeds from sale of life insurance policies			55,444
Other	(2,059)	(1,099)	(1,931)
Net cash flow used for investing activities	(1,009,401)	(872,994)	(782,007)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	136,307	476,081	470,353
Repayment of long-term debt	(122,828)	(654,286)	(655,169)
Short-term borrowings and payments net	60,950	92,175	(16,600)

Dividends paid on common stock	(235,244)	(225,075)	(221,728)
Common stock equity issuance	17,319	15,955	15,841
Distributions to noncontrolling interests	(17,385)	(10,529)	(10,210)
Other	299	170	(2,668)
Net cash flow used for financing activities	(160,582)	(305,509)	(420,181)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(16,676)	(7,381)	(76,605)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	26,202	33,583	110,188
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 9,526	$ 26,202	$ 33,583

See Notes to Pinnacle West s Consolidated Financial Statements.

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PINNACLE WEST CAPITAL CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(dollars in thousands, except per share amounts)

	Year Ended December 31, 2013	2012	2011
COMMON STOCK (Note 7)			
Balance at beginning of year	$ 2,466,923	$ 2,444,247	$ 2,421,372
Issuance of common stock	24,635	22,676	22,875
Balance at end of year	2,491,558	2,466,923	2,444,247
TREASURY STOCK (Note 7)			
Balance at beginning of year	(4,211)	(4,717)	(2,239)
Purchase of treasury stock	(9,727)	(4,607)	(3,720)
Reissuance of treasury stock used for stock compensation	9,630	5,113	1,242
Balance at end of year	(4,308)	(4,211)	(4,717)
RETAINED EARNINGS			
Balance at beginning of year	1,624,102	1,534,483	1,423,961
Net income attributable to common shareholders	406,074	381,542	339,473
Common stock dividends declared ($2.23, $2.67, and $2.10 per share)	(244,903)	(291,923)	(228,951)
Balance at end of year	1,785,273	1,624,102	1,534,483
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)			
Balance at beginning of year	(114,008)	(152,163)	(159,767)
Other comprehensive income attributable to common shareholders	35,955	38,155	7,604
Balance at end of year	(78,053)	(114,008)	(152,163)
NONCONTROLLING INTERESTS			
Balance at beginning of year	129,483	108,736	91,899
Net income attributable to noncontrolling interests	33,892	31,622	27,467
Net capital activities by noncontrolling interests	(17,385)	(10,875)	(10,630)
Balance at end of year	145,990	129,483	108,736
TOTAL EQUITY	$ 4,340,460	$ 4,102,289	$ 3,930,586
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS			
Net income attributable to common shareholders	$ 406,074	$ 381,542	$ 339,473
Other comprehensive income	35,955	38,155	7,605
Comprehensive income attributable to common shareholders	$ 442,029	$ 419,697	$ 347,078

See Notes to Pinnacle West s Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Description of Business and Basis of Presentation

Pinnacle West is a holding company that conducts business through its subsidiaries, APS and El Dorado, and formerly SunCor and APSES. APS, our wholly-owned subsidiary, is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. APS accounts for essentially all of our revenues and earnings, and is expected to continue to do so. SunCor was a developer of residential, commercial and industrial real estate projects and essentially all of these assets were sold in 2009 and 2010. In February 2012, SunCor filed for protection under the United States Bankruptcy Code to complete an orderly liquidation of its business. All activities for SunCor are reported as discontinued operations. APSES provided energy-related projects to commercial and industrial retail customers in competitive markets in the western United States. APSES was sold in 2011 and is reported as discontinued operations. El Dorado is an investment firm.

Pinnacle West s Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS and El Dorado, and formerly SunCor and APSES. APS s consolidated financial statements include the accounts of APS and certain VIEs relating to the Palo Verde sale leaseback. Intercompany accounts and transactions between the consolidated companies have been eliminated.

We consolidate VIEs for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. In performing our primary beneficiary analysis, we consider all relevant facts and circumstances, including the design and activities of the VIE, the terms of the contracts the VIE has entered into, and which parties participated significantly in the design or redesign of the entity. We continually evaluate our primary beneficiary conclusions to determine if changes have occurred which would impact our primary beneficiary assessments. We have determined that APS is the primary beneficiary of certain VIE lessor trusts relating to the Palo Verde sale leaseback, and therefore APS consolidates these entities (see Note 19).

Our consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments, except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations and cash flows for the periods presented.

Certain line items are presented in more detail on the Consolidated Balance Sheets and Consolidated Statements of Cash Flows than was presented in the prior years. Other line items are more condensed than the previous presentation. The prior year amounts were reclassified to conform to the current year presentation. These reclassifications had no impact on total assets or net cash flow provided by operating activities. The following tables show the impacts of the reclassifications of prior years (previously reported) amounts (dollars in thousands):

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PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Balance Sheets - December 31, 2012	As previously reported	Reclassifications to conform to current year presentation	Amount reported after reclassification to conform to current year presentation
Long-Term Debt less Current Maturities			
Long-term debt less current maturities	$ 3,160,219	$ 38,869	$ 3,199,088
Long-Term Debt less Current Maturities			
Palo Verde sale leaseback lessor notes less current maturities	38,869	(38,869)	

Statement of Cash Flows for the Year Ended December 31, 2012	As previously reported	Reclassifications to conform to current year presentation	Amount reported after reclassification to conform to current year presentation
Cash Flows from Operating Activities			
Deferred income taxes	$ 228,602	$ (41,579)	$ 187,023
Deferred investment tax credit		41,579	41,579
Accrued taxes and income tax receivable	8,693	(8,693)	
Income tax receivable		(4,043)	(4,043)
Accrued taxes		12,736	12,736

Statement of Cash Flows for the Year Ended December 31, 2011	As previously reported	Reclassifications to conform to current year presentation	Amount reported after reclassification to conform to current year presentation
Cash Flows from Operating Activities			
Deferred income taxes	$ 176,192	$ (58,240)	$ 117,952
Deferred investment tax credit		58,240	58,240
Accrued taxes and income tax receivable	12,068	(12,068)	
Income tax receivable		3,983	3,983
Accrued taxes		8,085	8,085

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with GAAP. The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Accounting

APS is regulated by the ACC and FERC. The accompanying financial statements reflect the rate-making policies of these commissions. As a result, we capitalize certain costs that would be included as expense 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.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory environment and recent rate orders applicable to APS or other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

See Note 3 for additional information.

Electric Revenues

We derive electric revenues primarily from sales of electricity to our regulated Native Load customers. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated by applying an average revenue/kWh by customer class to the number of estimated kWhs delivered but not billed. Differences historically between the actual and estimated unbilled revenues are immaterial. We exclude sales taxes and franchise fees on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on Pinnacle West s Consolidated Statements of Income. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called a book-out and usually occurs for contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and fuel and purchased power costs.

For the period January 1, 2010 through June 30, 2012, electric revenues also include proceeds for line extension payments for new or upgraded service in accordance with the 2009 Settlement Agreement (see Note 3). Effective July 1, 2012, as a result of the 2012 Settlement Agreement, these amounts are now recorded as contributions in aid of construction and are not included in electric revenues.

Some of our cost recovery mechanisms are alternative revenue programs. For alternative revenue programs that meet specified accounting criteria, we recognize revenues when the specific events permitting billing of the additional revenues have been completed.

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Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including accrued utility revenues. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management s best estimate of future collections success given the existing collections environment.

Property, Plant and Equipment

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- allowance for funds used during construction.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense, and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 12.

APS records a regulatory liability on its regulated assets for the difference between the amount that has been recovered in regulated rates and the amount calculated in accordance with guidance on accounting for asset retirement obligations. APS believes it can recover in regulated rates the costs calculated in accordance with this accounting guidance.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2013 were as follows:

- Fossil plant 18 years;
- Nuclear plant 26 years;
- Other generation 26 years;
- Transmission 37 years;
- Distribution 34 years; and
- Other 7 years.

APS applied for twenty-year extensions of its operating licenses for each of the three Palo Verde units in December 2008. On April 21, 2011, the NRC approved the extensions of the Palo Verde licenses. The nuclear plant remaining life takes into consideration an ACC decision which authorizes the use of the new Palo Verde nuclear plant lives, effective January 1, 2012.

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Pursuant to an ACC order, we defer operating costs related to APS s acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. See Note 3 for further discussion. These costs are deferred on the depreciation line of the Consolidated Statements of Income.

For the years 2011 through 2013, the depreciation rates ranged from a low of 0.45% to a high of 12.08%. The weighted-average rate was 3.00% for 2013, 2.71% for 2012, and 2.98% for 2011.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and an allowed return on the equity funds used for construction of regulated utility plant. Both the debt and equity components of AFUDC are non-cash amounts within the Consolidated Statement of Income. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 8.56% for 2013, 8.60% for 2012, and 10.25% for 2011. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

Materials and Supplies

APS values materials, supplies and fossil fuel inventory using a weighted-average cost method. APS materials, supplies and fossil fuel inventories are carried 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.

Fair Value Measurements

We account for derivative instruments, investments held in our nuclear decommissioning trust, certain cash equivalents and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Due to the short-term nature of net accounts receivable, accounts payable, and short-term borrowings, the carrying values of these instruments approximate fair value. Fair value measurements may also be applied on a nonrecurring basis to other assets and liabilities in certain circumstances such as impairments. We also disclose fair value information for our long-term debt, which is carried at amortized cost (see Note 6).

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market which we can access for the asset or liability in an orderly transaction between willing market participants on the measurement date. Inputs to fair value may include observable and unobservable data. We maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

We determine fair market value using observable inputs such as actively-quoted prices for identical instruments when available. When actively quoted prices are not available for the identical instruments, we use other observable inputs, such as prices for similar instruments, other corroborative market information, or prices provided by other external sources. For options, long-term contracts and other contracts for which observable price data are not available, we use models and other valuation methods, which may incorporate unobservable inputs to determine fair market value.

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The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods.

See Note 14 for additional information about fair value measurements.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emission allowances and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial instruments including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power expenses in our Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

We account for our derivative contracts in accordance with derivatives and hedging guidance, which requires all derivatives not qualifying for a scope exception to be measured at fair value on the balance sheet as either assets or liabilities. Transactions with counterparties that have master netting arrangements are reported net on the balance sheet. See Note 17 for additional information about our derivative instruments.

Loss Contingencies and Environmental Liabilities

Pinnacle West and APS are involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses and environmental liabilities are recorded when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, Pinnacle West and APS record a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Retirement Plans and Other Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan for the employees of Pinnacle West and its subsidiaries. We also sponsor an other postretirement benefit plan for the employees of Pinnacle West and our subsidiaries that provides medical and life insurance benefits to retired employees. Pension and other postretirement benefit expense are determined by actuarial valuations, based on assumptions that are evaluated annually. See Note 8 for additional information on pension and other postretirement benefits.

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Nuclear Fuel

APS amortizes nuclear fuel by using the unit-of-production method. The unit-of-production method is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel and charges APS $0.001 per kWh of nuclear generation. See Note 11 for information on spent nuclear fuel disposal costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by guidance relating to accounting for income taxes. We file our federal income tax return on a consolidated basis, and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each first-tier subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. The income tax accounts reflect the tax and interest associated with management s estimate of the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement for all known and measurable tax exposures (see Note 4).

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.

The following table summarizes supplemental Pinnacle West cash flow information for each of the last three years (dollars in thousands):

	Years ended December 31,		
	2013	**2012**	**2011**
Cash paid during the period for:			
Income taxes, net of refunds	$ 18,537	$ 2,543	$ 10,324
Interest, net of amounts capitalized	184,010	200,923	217,789

Significant non-cash investing and financing activities:						
Accrued capital expenditures	$	33,184	$	26,208	$	27,245
Dividends declared but not paid		62,528		59,789		
Liabilities assumed relating to acquisition of SCE Four Corners interest (see Note 3)		145,609				

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Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets, primarily APS s software, on Pinnacle West s Consolidated Balance Sheets. The intangible assets are amortized over their finite useful lives. Amortization expense was $53 million in 2013, $50 million in 2012, and $47 million in 2011. Estimated amortization expense on existing intangible assets over the next five years is $47 million in 2014, $38 million in 2015, $29 million in 2016, $19 million in 2017, and $7 million in 2018. At December 31, 2013, the weighted-average remaining amortization period for intangible assets was 6 years.

Investments

El Dorado accounts for its investments using either the equity method (if significant influence) or the cost method (if less than 20% ownership).

Our investments in the nuclear decommissioning trust fund are accounted for in accordance with guidance on accounting for certain investments in debt and equity securities. See Note 14 and Note 20 for more information on these investments.

Business Segments

Pinnacle West s reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electricity service to Native Load customers) and related activities and includes electricity generation, transmission and distribution. All other segment activities are insignificant.

2. New Accounting Standards

During 2013, we adopted, on a retrospective basis, new guidance relating to balance sheet offsetting disclosures. The new guidance requires enhanced disclosures regarding an entity s ability to offset certain instruments on the balance sheet and how offsetting impacts the balance sheet. The adoption of this guidance resulted in expanded disclosures relating to our derivative instruments (see Note 17), but did not impact our financial statement results.

During 2013, we also adopted, on a prospective basis, new guidance relating to reporting amounts reclassified from accumulated other comprehensive income. This guidance requires new disclosures relating to accumulated other comprehensive income and how reclassifications from accumulated other comprehensive income impact net income. As a result of adopting this new guidance, we have included a new footnote disclosure to provide the information required by the new standard (see Notes 21 and S-4). The adoption of this guidance did not impact our financial statement results.

In July 2013, new guidance was issued which will generally require entities to present unrecognized tax benefits as a reduction to any available deferred tax asset for a net operating loss, a similar tax loss, or a tax credit carryforward. The intent of this guidance is to eliminate diversity in practice in the presentation of certain unrecognized tax benefits. The new guidance is effective for us during the first quarter of 2014, and is permitted to be adopted using either a prospective or retrospective application. Currently, we do not present unrecognized tax benefits as a reduction to deferred tax asset carryforwards on the balance sheet. As a result, the adoption of this new guidance

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will impact our balance sheet presentation; however, we do not expect these presentation changes to be material to our balance sheet. The adoption of this new guidance will not impact our results of operations or cash flows.

3. Regulatory Matters

Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. APS requested that the increase become effective July 1, 2012. The request would have increased the average retail customer bill by approximately 6.6%. On January 6, 2012, APS and other parties to the general retail rate case entered into the 2012 Settlement Agreement detailing the terms upon which the parties agreed to settle the rate case. On May 15, 2012, the ACC approved the 2012 Settlement Agreement without material modifications.

Settlement Agreement

The 2012 Settlement Agreement provides for a zero net change in base rates, consisting of: (1) a non-fuel base rate increase of $116.3 million; (2) a fuel-related base rate decrease of $153.1 million (to be implemented by a change in the Base Fuel Rate from $0.03757 to $0.03207 per kWh; and (3) the transfer of cost recovery for certain renewable energy projects from the RES surcharge to base rates in an estimated amount of $36.8 million.

APS also agreed not to file its next general rate case before May 31, 2015, and not to request that its next general retail rate increase be effective prior to July 1, 2016. The 2012 Settlement Agreement allows APS to request a change to its base rates during the stay-out period in the event of an extraordinary event that, in the ACC s judgment, requires base rate relief in order to protect the public interest. Nor is APS precluded from seeking rate relief, or any other party to the 2012 Settlement Agreement precluded from petitioning the ACC to examine the reasonableness of APS s rates, in the event of significant regulatory developments that materially impact the financial results expected under the terms of the 2012 Settlement Agreement.

Other key provisions of the 2012 Settlement Agreement include the following:

- An authorized return on common equity of 10.0%;

- A capital structure comprised of 46.1% debt and 53.9% common equity;

- A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;

- Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:

- Deferral of 25% in 2012, 50% in 2013 and 75% for 2014 and subsequent years if Arizona property tax rates increase; and

- Deferral of 100% in all years if Arizona property tax rates decrease;

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- A procedure to allow APS to request rate adjustments prior to its next general rate case related to APS s acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners (APS made its filing under this provision on December 30, 2013, which would result in an average bill impact to residential customers of approximately 2% if approved as requested);

- Implementation of a Lost Fixed Cost Recovery rate mechanism to support energy efficiency and distributed renewable generation;

- Modifications to the Environmental Improvement Surcharge to allow for the recovery of carrying costs for capital expenditures associated with government-mandated environmental controls, subject to an existing cents per kWh cap on cost recovery that could produce up to approximately $5 million in revenues annually;

- Modifications to the PSA, including the elimination of the 90/10 sharing provision;

- A limitation on the use of the RES surcharge and the DSMAC to recoup capital expenditures not required under the terms of the 2009 Settlement Agreement discussed below;

- Allowing a negative credit that existed in the PSA rate to continue until February 2013, rather than being reset on the anticipated July 1, 2012 rate effective date;

- Modification of the TCA to streamline the process for future transmission-related rate changes; and

- Implementation of various changes to rate schedules, including the adoption of an experimental buy-through rate that could allow certain large commercial and industrial customers to select alternative sources of generation to be supplied by APS.

The 2012 Settlement Agreement was approved by the ACC on May 15, 2012, with new rates effective on July 1, 2012. This accomplished a goal set by the parties to the 2009 Settlement Agreement to process subsequent rate cases within twelve months of sufficiency findings from the ACC staff, which generally occurs within 30 days after the filing of a rate case.

2008 General Retail Rate Case On-Going Impacts

On December 30, 2009, the ACC issued an order approving the 2009 Settlement Agreement entered into by APS and twenty-one other parties. The 2009 Settlement Agreement contains certain on-going requirements, commitments and authorizations that will survive the 2012 Settlement Agreement, including the following:

- A commitment from APS to reduce average annual operational expenses by at least $30 million from 2010 through 2014;

- Authorization and requirements of equity infusions into APS of $700 million during the period beginning June 1, 2009 through December 31, 2014 and compliance with various

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financial conditions, including the maintenance of a prescribed capital structure (APS was able to meet these conditions without the need for additional equity infusions beyond the $253 million infused into APS in the second quarter of 2010); and

- Renewable energy programs that require APS to expand its use of renewable energy through 2015, as well as allow for concurrent recovery of renewable energy expenses.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs through the following recovery mechanisms.

Renewable Energy Standard. In 2006, the ACC approved the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas and geothermal technologies. In order to achieve these requirements, the ACC allows APS to include a RES surcharge as part of customer bills to recover the approved amounts for use on renewable energy projects. Each year APS is required to file a five-year implementation plan with the ACC and seek approval for funding the upcoming year s RES budget.

On July 12, 2013, APS filed its annual RES implementation plan, covering the 2014-2018 timeframe and requesting a 2014 RES budget of approximately $143 million. In a final order dated January 7, 2014, the ACC approved the requested budget. Also in 2013, the ACC conducted a hearing to consider APS s proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules so that utilities can establish compliance without using renewable energy credits.

On July 12, 2013, APS filed an application with the ACC proposing a solution to fix the cost shift brought by the current net metering rules. In its application, APS requested that the ACC cause all new residential customers installing new rooftop solar systems to either: (i) take electric service under APS s demand-based ECT-2 rate and remain eligible for net metering; or (ii) take service under the customer s existing rate as if no distributed energy system was installed and receive a bill credit for 100% of the distributed energy system s output at a market-based price. APS also proposed that the ACC: (i) grandfather current rates and use of net metering for existing and immediately pending distributed energy customers; and (ii) continue using direct cash incentives for new distributed energy installations.

On December 3, 2013, the ACC issued its order on APS s net metering proposal. The ACC instituted a charge on future customers who install rooftop solar panels and directed APS to provide quarterly reports on the pace of rooftop solar adoption to assist the ACC in considering further increases. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electricity grid. The new policy will be in effect until the next APS rate case.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the

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electrical grid. ACC professional staff and the state s Residential Utility Consumer Office, among other organizations, also agreed that a cost shift exists. The fixed charge does not increase APS s revenue, but instead will modestly reduce the impact of the cost shift on non-solar customers. The ACC acknowledged that the new charge addresses only a portion of the cost shift.

Demand Side Management Adjustor Charge. The ACC Electric Energy Efficiency Standards require APS to submit a Demand Side Management Implementation Plan for review by and approval of the ACC.

On June 1, 2011, APS filed its 2012 Demand Side Management Implementation Plan consistent with the ACC s Electric Energy Efficiency Rules, which became effective January 1, 2011. The 2012 requirement under such standards is for cumulative energy efficiency savings of 3% of APS retail sales for the prior year. This energy savings requirement is slightly higher than the goal established by the 2009 Settlement Agreement (2.75% of total energy resources for the same two-year period). The ACC issued an order on April 4, 2012, approving recovery of approximately $72 million of APS s energy efficiency and demand side management program costs. This amount was recovered by the then existing DSMAC over a twelve-month period beginning March 1, 2012. This amount does not include $10 million already being recovered in general retail base rates, but does include amortization of 2009 costs (approximately $5 million of the $72 million).

On June 1, 2012, APS filed its 2013 Demand Side Management Implementation Plan. In 2013, the standards require APS to achieve cumulative energy savings equal to 5% of its 2012 retail energy sales. Later in 2012, APS filed a supplement to its plan that included a proposed budget for 2013 of $87.6 million.

The ACC Staff recommendation and proposed order, issued on October 30, 2013, largely recommended continuing the status quo, although at lower funding levels. ACC Staff recommended approval of all existing cost-effective energy efficiency and demand response programs and a budget of $68.9 million going forward. APS expects to receive a decision from the ACC in early 2014.

On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Rules should be modified or abolished. This spring the ACC will hold a series of three workshops to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

PSA Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

- APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;

- an adjustment to the PSA rate is made annually each February 1st (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;

- the PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);

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- the PSA rate includes (a) a Forward Component, under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a Historical Component, under which differences between actual fuel and purchased power costs and those recovered through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a Transition Component, under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and

- the PSA rate may not be increased or decreased more than $0.004 per kWh in a year without permission of the ACC.

The following table shows the changes in the deferred fuel and purchased power regulatory asset for 2013 and 2012 (dollars in millions):

	Twelve Months Ended December 31,			
		2013		2012
Beginning balance	$	73	$	28
Deferred fuel and purchased power costs - current period		(21)		(72)
Amounts (charged) credited to customers		(31)		117
Ending balance	$	21	$	73

The PSA rate for the PSA year beginning February 1, 2014 is $0.001557 per kWh, as compared to $0.001329 per kWh for the prior year. This represents a $0.000228 per kWh increase over the 2013 PSA charge. This new rate is comprised of a forward component of $0.001277 per kWh and a historical component of $0.000280 per kWh. Any uncollected (overcollected) deferrals during the 2014 PSA year will be included in the calculation of the PSA rate for the PSA year beginning February 1, 2015.

Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters. In July 2008, FERC approved an Open Access Transmission Tariff for APS to move from fixed rates to a formula rate-setting methodology in order to more accurately reflect and recover the costs that APS incurs in providing transmission services. A large portion of the rate represents charges for transmission services to serve APS s retail customers (Retail Transmission Charges). In order to recover the Retail Transmission Charges, APS was previously required to file an application with, and obtain approval from, the ACC to reflect changes in Retail Transmission Charges through the TCA. Under the terms of the 2012 Settlement Agreement (discussed above), however, an adjustment to rates to recover the Retail Transmission Charges will be made annually each June 1 and will go into effect automatically unless suspended by the ACC.

The formula rate is updated each year effective June 1 on the basis of APS s actual cost of service, as disclosed in APS s FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected. APS reviews the proposed formula rate filing amounts with the ACC staff. Any items or adjustments which are not agreed to by APS and the ACC staff can remain in dispute until

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settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charge because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts.

Effective June 1, 2012, APS s annual wholesale transmission rates for all users of its transmission system increased by approximately $16 million for the twelve-month period beginning June 1, 2012 in accordance with the FERC-approved formula.

Effective June 1, 2013, APS s annual wholesale transmission rates for all users of its transmission system increased by approximately $26 million for the twelve-month period beginning June 1, 2013 in accordance with the FERC-approved formula. Pursuant to the 2012 Settlement Agreement (discussed above), an adjustment to APS s retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2013.

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to distributed generation such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were established in the 2012 Settlement Agreement and amount to approximately 3.1 cents per residential kWh lost and 2.3 cents per non-residential kWh lost. The kWh s lost from energy efficiency are based on a third-party evaluation of APS s energy efficiency programs. Distributed generation sales losses are determined from the metered output from the distributed generation units or if metering is unavailable, through accepted estimating techniques.

APS filed its first LFCR adjustment on January 15, 2013 and will file for a LFCR adjustment every January thereafter. On February 12, 2013, the ACC approved a LFCR adjustment of $5.1 million, representing a pro-rated amount for 2012 since the 2012 Settlement Agreement went into effect on July 1, 2012. APS filed its 2014 annual LFCR adjustment on January 15, 2014, requesting a LFCR adjustment of $25.3 million, effective March 1, 2014. APS anticipates that the ACC will consider whether to approve APS s LFCR adjustment prior to the end of March 2014.

Deregulation

On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a market basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. The ACC opened a new docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. Workshops in this docket are expected to be held in 2014.

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Four Corners

On December 30, 2013, APS purchased SCE s 48% ownership interest in each of Units 4 and 5 of Four Corners. As a result of this purchase, APS now owns 63% of Units 4 and 5. APS has a total entitlement from Four Corners of 970 MW. The final purchase price for the interest was approximately $182 million. APS acquired assets and assumed certain of SCE s decommissioning and mine reclamation obligations. We have recognized plant-in-service, net of accumulated depreciation, of $316 million, which includes an acquisition adjustment of $255 million. In addition, we have recognized a liability of $34 million for the decommissioning obligations, $93 million for the mine reclamation obligations, $18 million of other various liabilities, and $11 million of construction work in progress relating to this purchase. These amounts are subject to revision during the measurement period, not to exceed one year, to the extent additional information is obtained about the facts and circumstances that existed as of the acquisition date. While we expect the ACC to approve the recovery of the acquisition adjustment, should recovery be disallowed, it will be reclassified from plant-in-service to goodwill, subject to impairment testing. The decommissioning and mine reclamation obligations were recognized at their fair value. Because APS s rates are regulated, APS expects to recover the costs of the acquired plant assets, including a return on its investment based on its cost of capital. APS believes this return is consistent with what a market participant would consider to be fair value in APS s regulatory environment. Accordingly, APS believes the cost of the plant assets approximate their fair value.

The 2012 Settlement Agreement includes a procedure to allow APS to request rate adjustments prior to its next general rate case related to APS s acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. APS made its filing under this provision on December 30, 2013. This includes deferral for future recovery of all non-fuel operating cost for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Four Corners Units 1-3. The 2012 Settlement Agreement also provides for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Four Corners Units 1-3. The deferral balance related to the acquisition of SCE s interest in Units 4 and 5 and the closure of Four Corners Units 1-3 was $37 million as of December 31, 2013.

As part of APS s acquisition of SCE s interest in Units 4 and 5 of Four Corners, APS and SCE agreed, via a Transmission Termination Agreement, that upon closing of the acquisition, the companies would terminate an existing transmission agreement (Transmission Agreement) between the parties that provides transmission capacity on a system (the Arizona Transmission System) for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE will assign its 1,555 MW capacity rights over the Arizona Transmission System to third-parties, including 300 MW to APS s marketing and trading group for transmission of the additional power received from Four Corners. This arrangement becomes effective upon FERC approval and will remain in effect until the net payments received by SCE in connection with the assignments reach $40 million, at which time the arrangement and the Transmission Agreement will terminate. APS believes that FERC will approve the alternate arrangement as filed but, if not approved, SCE and APS will again be subject to the terms of the Transmission Termination Agreement. As we previously disclosed, APS believes that the original denial by FERC of rate recovery under the Transmission Termination Agreement constitutes the failure of a condition that relieves APS of its obligations under that agreement. If APS and SCE were unable to determine a resolution through negotiation, the Transmission Termination Agreement requires that disputes be resolved through arbitration. APS is unable to predict the outcome of this matter if it proceeds to arbitration.

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Regulatory Assets and Liabilities

The detail of regulatory assets is as follows (dollars in millions):

	Remaining Amortization Period	December 31, 2013 Current	December 31, 2013 Non-Current	December 31, 2012 Current	December 31, 2012 Non-Current
Pension and other postretirement benefits	(a)	$	$ 314	$	$ 780
Income taxes AFUDC equity	2043	4	105	4	92
Deferred fuel and purchased power mark-to-market (Note 17)	2016	5	29	19	21
Transmission vegetation management	2016	9	14	9	23
Coal reclamation	2038	8	18	8	24
Palo Verde VIEs (Note 19)	2046		41		38
Deferred compensation	2036		34		34
Deferred fuel and purchased power (b) (c)	2014	21		73	
Tax expense of Medicare subsidy	2023	2	15	2	17
Loss on reacquired debt	2034	1	17	2	18
Income taxes investment tax credit basis adjustment	2043	1	39	1	26
Pension and other postretirement benefits deferral	2015	8	4	8	13
Four Corners cost deferral	2024		37		
Lost fixed cost recovery	2014	25		7	
Transmission cost adjustor	2015	8	2	10	
Retired power plant costs	2020	3	18		
Other	Various	2	25	1	14
Total regulatory assets (d)		$ 97	$ 712	$ 144	$ 1,100

(a) This asset represents the future recovery of under-funded pension and other postretirement benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future revenues. See Note 8 for further discussion.

(b) See Cost Recovery Mechanisms discussion above.

(c) Subject to a carrying charge.

(d) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in Transmission Rates and Transmission Cost Adjustor.

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The detail of regulatory liabilities is as follows (dollars in millions):

	Remaining Amortization Period	December 31, 2013 Current	December 31, 2013 Non-Current	December 31, 2012 Current	December 31, 2012 Non-Current
Removal costs	(a)	$ 28	$ 303	$ 27	$ 321
Asset retirement obligations	(a)		266		256
Renewable energy standard (b)	2015	33	15	43	
Income taxes change in rates	2043		74		66
Spent nuclear fuel	2047	6	36	10	36
Deferred gains on utility property	2019	2	10	2	12
Income taxes deferred investment tax credit	2043	3	79	2	52
Demand side management (b)	2014	27		4	
Other	Various		18		16
Total regulatory liabilities		$ 99	$ 801	$ 88	$ 759

(a) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal (see Note 12).

(b) See Cost Recovery Mechanisms discussion above.

4. Income Taxes

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statement purposes. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using currently enacted income tax rates.

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction and pension and other postretirement benefits. The regulatory liabilities primarily relate to deferred taxes resulting from investment tax credits (ITC) and the change in income tax rates.

In accordance with regulatory requirements, APS ITCs are deferred and are amortized over the life of the related property with such amortization applied as a credit to reduce current income tax expense in the statement of income.

The $70 million long-term income tax receivable on the Consolidated Balance Sheets as of December 31, 2012 represented the anticipated refund related to an APS tax accounting method change approved by the IRS in the third quarter of 2009. On July 9, 2013, IRS guidance was released which provided clarification regarding the timing and amount of this cash receipt. As a result of this guidance, uncertain tax positions decreased $67 million during the third quarter. This decrease in uncertain tax positions resulted in a corresponding increase to the total anticipated refund due from the IRS and an offsetting increase in long-term deferred tax liabilities. Additionally, as a result of this IRS guidance, the resulting $137 million anticipated refund was reclassified to current income tax receivable.

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During the year ended December 31, 2013, the IRS finalized the examination of tax returns for the years ended December 31, 2008 and 2009, and the $137 million anticipated refund was reduced by approximately $4 million to reflect the outcome of this examination. On December 17, 2013, the Joint Committee on Taxation approved the anticipated refund. Cash related to this refund was received in the first quarter of 2014.

On September 13, 2013, the U.S. Treasury Department released final income tax regulations on the deduction and capitalization of expenditures related to tangible property. These final regulations apply to tax years beginning on or after January 1, 2014. Several of the provisions within the regulations will require a tax accounting method change to be filed with the IRS, resulting in a cumulative effect adjustment. To account for the adoption of these regulations, plant-related long-term deferred tax liabilities decreased by $84 million, with the offsetting decrease to current deferred income tax assets. Prior to the issuance of these regulations, this $84 million would have been repaid over 20 years through lower tax depreciation deductions.

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax (see Note 19). As a result, there is no income tax expense associated with the VIEs recorded on the Consolidated Statements of Income.

The following is a tabular reconciliation of the total amounts of unrecognized tax benefits, excluding interest and penalties, at the beginning and end of the year that are included in accrued taxes and unrecognized tax benefits (dollars in thousands):

	2013	2012	2011
Total unrecognized tax benefits, January 1	$ 133,422	$ 136,005	$ 127,595
Additions for tax positions of the current year	3,516	5,167	10,915
Additions for tax positions of prior years	13,158		
Reductions for tax positions of prior years for:			
Changes in judgment	(108,099)	(7,729)	(1,555)
Settlements with taxing authorities			(124)
Lapses of applicable statute of limitations		(21)	(826)
Total unrecognized tax benefits, December 31	$ 41,997	$ 133,422	$ 136,005

Included in the balances of unrecognized tax benefits at December 31, 2013, 2012 and 2011 were approximately $10 million, $10 million and $8 million, respectively, of tax positions that, if recognized, would decrease our effective tax rate.

As of the balance sheet date, the tax year ended December 31, 2010 and all subsequent tax years remain subject to examination by the IRS. With a few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 2010.

We reflect interest and penalties, if any, on unrecognized tax benefits in the Consolidated Statements of Income as income tax expense. The amount of interest recognized in the Consolidated

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Statements of Income related to unrecognized tax benefits was a pre-tax benefit of $4 million for 2013, a pre-tax expense of $4 million for 2012, and a pre-tax expense of $3 million for 2011.

The total amount of accrued liabilities for interest recognized in the Consolidated Balance Sheets related to unrecognized tax benefits was less than $1 million as of December 31, 2013, $13 million as of December 31, 2012 and $9 million as of December 31, 2011. To the extent that matters are settled favorably, this amount could reverse and decrease our effective tax rate. Additionally, as of December 31, 2013, we have recognized $5 million of interest income to be received on the overpayment of income taxes for certain adjustments that we have filed, or will file, with the IRS.

The components of income tax expense are as follows (dollars in thousands):

	Year Ended December 31,		
	2013	**2012**	**2011**
Current:			
Federal	$ (81,784)	$ (3,493)	$ (310)
State	10,537	8,395	15,140
Total current	(71,247)	4,902	14,830
Deferred:			
Federal	279,973	200,322	159,566
State	21,865	28,280	16,626
Total deferred	301,838	228,602	176,192
Total income tax expense	230,591	233,504	191,022
Less: income tax expense (benefit) on discontinued operations		(3,813)	7,418
Income tax expense continuing operations	$ 230,591	$ 237,317	$ 183,604

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The following chart compares pretax income from continuing operations at the 35% federal income tax rate to income tax expense continuing operations (dollars in thousands):

	Year Ended December 31, 2013	2012	2011
Federal income tax expense at 35% statutory rate	$ 234,695	$ 229,709	$ 188,733
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	21,387	23,819	19,594
Credits and favorable adjustments related to prior years resolved in current year	(3,356)		
Medicare Subsidy Part-D	823	483	823
Allowance for equity funds used during construction (see Note 1)	(6,997)	(6,158)	(6,881)
Palo Verde VIE noncontrolling interest (see Note 19)	(11,862)	(11,065)	(9,636)
Other	(4,099)	529	(9,029)
Income tax expense continuing operations	$ 230,591	$ 237,317	$ 183,604

The following table shows the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

	December 31, 2013	2012
Current asset	$ 91,152	$ 152,191
Long-term liability	(2,351,882)	(2,151,371)
Deferred income taxes net	$ (2,260,730)	$ (1,999,180)

On February 17, 2011, Arizona enacted legislation (H.B. 2001) that included a four-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West has revised the tax rate applicable to reversing temporary items in Arizona. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2013 APS has recorded a regulatory liability of $75 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

On April 4, 2013, New Mexico enacted legislation (H.B. 641) that included a five-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, Pinnacle West has revised the tax rate applicable to reversing temporary items in New Mexico. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2013, APS has recorded a regulatory liability of $2

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million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

The components of the net deferred income tax liability were as follows (dollars in thousands):

	December 31, 2013	December 31, 2012
DEFERRED TAX ASSETS		
Risk management activities	$ 44,920	$ 72,243
Regulatory liabilities:		
Asset retirement obligation and removal costs	235,959	238,669
Unamortized investment tax credits	82,116	53,837
Other	42,609	33,764
Pension and other postretirement liabilities	198,642	408,764
Renewable energy incentives	65,434	66,941
Credit and loss carryforwards	133,070	139,022
Other	148,492	68,844
Total deferred tax assets	951,242	1,082,084
DEFERRED TAX LIABILITIES		
Plant-related	(2,903,730)	(2,584,166)
Risk management activities	(16,191)	(23,940)
Regulatory assets:		
Allowance for equity funds used during construction	(43,058)	(37,899)
Deferred fuel and purchased power	(8,282)	(28,858)
Deferred fuel and purchased power mark-to-market	(13,343)	(15,796)
Pension and other postretirement benefits	(129,250)	(316,757)
Other	(93,202)	(68,170)
Other	(4,916)	(5,678)
Total deferred tax liabilities	(3,211,972)	(3,081,264)
Deferred income taxes net	$ (2,260,730)	$ (1,999,180)

As of December 31, 2013, the deferred tax assets for credit and loss carryforwards relate to federal general business credits of $131 million which first begin to expire in 2031, and other federal and state loss carryforwards of $2 million which first begin to expire in 2018.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Lines of Credit and Short-Term Borrowings

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2013 (dollars in millions):

Credit Facility	Expiration	Amount Committed	Unused Amount (a)	Commitment Fees
Pinnacle West Revolving Credit Facility	November 2016	$ 200	$ 200	0.175%
APS Revolving Credit Facility	November 2016	500	347	0.125%
APS Revolving Credit Facility	April 2018	500	500	0.125%
Total		$ 1,200	$ 1,047	

(a) At December 31, 2013, APS had $153 million of outstanding commercial paper. Accordingly, at such date, the total combined amount available under its two $500 million credit facilities was $847 million.

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs.

Pinnacle West

At December 31, 2013, the Pinnacle West credit facility, which terminates in November 2016, was available to refinance indebtedness of the Company and for other general corporate purposes, including credit support for its $200 million commercial paper program. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2013, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit and no commercial paper borrowings.

APS

On April 9, 2013, APS refinanced its $500 million revolving credit facility that would have matured in February 2015, with a new $500 million facility. The new revolving credit facility matures in April 2018.

At December 31, 2013, APS had two credit facilities totaling $1 billion, including a $500 million credit facility that was refinanced in April 2013 (see above) and a $500 million credit facility that matures in November 2016. APS may increase the amount of each facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS can use these facilities to refinance indebtedness and for other general corporate purposes. Interest rates are based on APS s senior unsecured debt credit ratings.

APS may increase the amount of each facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use these facilities to refinance indebtedness and for other general corporate purposes. Interest rates are based on APS s senior unsecured debt credit ratings.

The facilities described above are available to support APS s $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2013, APS had no outstanding borrowings or letters of credit under its revolving credit facilities. In addition, APS had commercial paper borrowings of $153 million at December 31, 2013.

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PINNACLE WEST CAPITAL CORPORATION
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See Financial Assurances in Note 11 for a discussion of APS s separate outstanding letters of credit.

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2012 (dollars in millions):

Credit Facility	Expiration	Amount Committed	Unused Amount (a)	Commitment Fees
Pinnacle West Revolving Credit Facility	November 2016	$ 200	$ 200	0.225%
APS Revolving Credit Facility	November 2016	500	408	0.175%
APS Revolving Credit Facility	February 2015	500	500	0.20%
Total		$ 1,200	$ 1,108	

(a) At December 31, 2012, APS had $92 million of outstanding commercial paper. Accordingly, at such date the total combined amount available under its two $500 million credit facilities was $908 million.

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs.

Pinnacle West

At December 31, 2012, the Pinnacle West credit facility, which matures in November 2016, was available to refinance indebtedness of the Company and for other general corporate purposes, including credit support for its $200 million commercial paper program. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At December 31, 2012, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit and no commercial paper borrowings.

APS

APS may increase the amount of each facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use these facilities to refinance indebtedness and for other general corporate purposes. Interest rates are based on APS s senior unsecured debt credit ratings.

The facilities described above are available to support APS s $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2012, APS had no outstanding borrowings or letters of credit under its revolving credit facilities. In addition, APS had commercial paper borrowings of $92 million at December 31, 2012.

See Financial Assurances in Note 11 for a discussion of APS s separate outstanding letters of credit.

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Debt Provisions

Although provisions in APS s articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it (a) approved APS s short-term debt authorization equal to a sum of (i) 7% of APS s capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power), (b) approved an increase in APS s long-term debt authorization from $4.2 billion to $5.1 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs, and (c) authorized APS to enter into derivative financial instruments for the purpose of managing interest rate risk associated with its long- and short-term debt. This financing order is set to expire on December 31, 2017.

6. Long-Term Debt and Liquidity Matters

All of Pinnacle West s and APS s debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2013 and 2012 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2013	December 31, 2012
APS				
Pollution Control Bonds:				
Variable	2029-2038	(b)	$ 75,580	$ 75,580
Fixed	2024-2034	1.25%-6.00%	426,125	490,275
Total Pollution Control Bonds			501,705	565,855
Senior unsecured notes	2014-2042	4.50%-8.75%	2,675,000	2,575,000
Palo Verde sale leaseback lessor notes	2015	8.00%	38,869	65,547
Unamortized discount			(8,732)	(9,486)
Unamortized premium			5,047	
Total APS long-term debt			3,211,889	3,196,916
Less current maturities	(d)		540,424	122,828
Total APS long-term debt less current maturities			2,671,465	3,074,088
Pinnacle West				
Term loan	2015	(c)	125,000	125,000
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 2,796,465	$ 3,199,088

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.

(b) The weighted-average rate for the variable rate pollution control bonds was 0.03%-0.06% at December 31, 2013 and 0.13%-0.15% at December 31, 2012.

(c) The weighted-average interest rate was 1.269% at December 31, 2013 and 1.312% at December 31, 2012.

(d) Current maturities include $215 million of pollution control bonds expected to be remarketed in 2014 and $300 million in senior unsecured notes that mature in 2014.

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The following table shows principal payments due on Pinnacle West s and APS s total long-term debt (dollars in millions):

Year		Consolidated Pinnacle West		Consolidated APS
2014	$	540	$	540
2015		470		345
2016		358		358
2017				
2018		32		32
Thereafter		1,940		1,940
Total	$	3,340	$	3,215

Debt Fair Value

Our long-term debt fair value estimates are based on quoted market prices for the same or similar issues, and are classified within level 2 of the fair value hierarchy. Certain of our debt instruments contain third-party credit enhancements and, in accordance with GAAP, we do not consider the effect of these credit enhancements when determining fair value. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in millions):

	As of December 31, 2013	As of December 31, 2012