PINNACLE WEST CAPITAL CORP
Form 10-K
February 19, 2016
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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, 2015

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) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	ARIZONA PUBLIC SERVICE COMPANY (An Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0011170

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	$6,271,269,171 as of June 30, 2015
ARIZONA PUBLIC SERVICE COMPANY	$0 as of June 30, 2015

The number of shares outstanding of each registrant's common stock as of February 12, 2016

PINNACLE WEST CAPITAL CORPORATION	111,004,916 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 18, 2016 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 Combined Notes to Consolidated Financial Statements.

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
ARO	Asset retirement obligations
BART	Best available retrofit technology
Base Fuel Rate	The portion of APS's retail base rates attributable to fuel and purchased power costs
BCE	Bright Canyon Energy Corporation, a subsidiary of the Company
BHP Billiton	BHP Billiton New Mexico Coal, Inc.
BNCC	BHP Navajo Coal Company
CAISO	California Independent System Operator
CCR	Coal combustion residuals
Cholla	Cholla Power Plant
dc	Direct Current
distributed energy systems	Small-scale renewable energy technologies that are located on customers' properties, such as rooftop solar systems
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOJ	United States Department of Justice
DSM	Demand side management
DSMAC	Demand side management adjustment charge
EES	Energy Efficiency Standard
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
NERC	North American Electric Reliability Corporation
NRC	United States Nuclear Regulatory Commission
NTEC	Navajo Transitional Energy Company, LLC
OCI	Other comprehensive income
OSM	Office of Surface Mining Reclamation and Enforcement
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
SIB	System Improvement Benefits
TCA	Transmission cost adjustor
VIE	Variable interest entity

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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” a words. Because actual results may differ 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 and of debt and equity capital investment;
- 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, including in real estate markets;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions;
- 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 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; 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 subsidiaries are El Dorado and BCE. Additional information related to these subsidiaries 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 6,186 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 2015, no single purchaser or user of energy accounted for more than 1.3% 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 used to supply energy to Native Load customers during 2015 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 was originally a 5-unit coal-fired power plant, which is 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 December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for SCE's interest was approximately $182 million. 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 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustment was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed in Note 3, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

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. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. The cash purchase price, which will be subject to certain adjustments at closing, is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016.

When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. On December 29, 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

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.

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 required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process and culminated in the issuance by the DOI of a record of decision on July 17, 2015. The record of decision provided the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015.

On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with the environmental review described above were not in accordance with applicable law. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

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In 2012, several environmental groups filed a lawsuit in federal district court against OSM challenging OSM's 2012 approval of a permit revision which allowed for the expansion of mining operations into a new area of the mine that serves Four Corners ("Area IV North"). In April 2015, the court issued an order invalidating the permit revision, thereby prohibiting mining in Area IV North until OSM takes action to cure the defect in its permitting process identified by the court. On December 29, 2015, OSM took action to cure the defect in its permitting process by issuing a revised environmental assessment and finding of no new significant impact, and reissued the permit. This action is subject to possible judicial review.

Cholla — Cholla was originally a 4-unit coal-fired power plant, which is 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. On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 10 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long term than the benefits that would have resulted from adding the emissions control equipment. APS closed Unit 2 on October 1, 2015. Following the closure of Unit 2, APS has a total entitlement from Cholla of 387 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 that runs through 2017. See "Current and Future Resources - Future Resources and Resource Plan" below for a discussion of future plans for Cholla.

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. See "Environmental Matters - EPA Environmental Regulation - Regional Haze Rules - Navajo Plant" below for a discussion of potential future plans for the Navajo Plant.

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 10 for information regarding APS's coal mine reclamation obligations.

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.

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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. The leaseback was originally scheduled to expire at the end of 2015 and contained options to renew the leases or to purchase the leased property for fair market value at the end of the lease terms. On July 7, 2014, APS exercised the fixed rate lease renewal options. The length of the renewal options resulted in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors. See Note 18 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 and conversion services through 2018 and 45% of its requirements in 2019-2025. The participants have also contracted for 100% of Palo Verde's enrichment services through 2020 and 20% of its enrichment services for 2021-2026; and all of Palo Verde's fuel assembly fabrication services through 2022.

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 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 sought 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. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified

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costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million.

APS's first claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2011 through June 30, 2014, was for $42.0 million (APS's share of this amount was $12.2 million), and payment was received on June 1, 2015. APS's second claim made pursuant to the terms of the August 18, 2014, settlement agreement, which was for the period July 1, 2014 through June 30, 2015, and was for $12.0 million (APS's share of this amount is $3.6 million), was submitted to the DOE on November 2, 2015. The second claim is presently being reviewed by DOE.

Amounts recovered in the lawsuit and settlement were recorded as adjustments to regulatory liability and had no impact on current income.

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 found that the DOE did not conduct a legally adequate fee assessment and 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. On May 16, 2014, the DOE notified all commercial nuclear power plant operators who are party to a Standard Contract that it reduced the one-mill fee to zero, thus effectively terminating the one-mill fee.

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.

On October 16, 2014, the NRC issued Volume 3 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume addresses repository safety after permanent closure, and its issuance is a key milestone in the Yucca Mountain licensing process. Volume 3 contains the staff's finding that the DOE's repository design meets the requirements that apply after the repository is permanently closed, including but not limited to the post-closure performance objectives in NRC's regulations.

On December 18, 2014, the NRC issued Volume 4 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume covers administrative and programmatic requirements for the repository. It documents the staff's evaluation of whether the DOE's

research and development and performance confirmation programs, as well as other administrative controls and systems, meet applicable NRC requirements. Volume 4 contains the staff's finding that most administrative and programmatic requirements in NRC regulations are met, except for certain requirements relating to ownership of land and water rights.

Publication of Volumes 3 and 4 does not signal whether or when the NRC might authorize construction of the repository.

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 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 Generic Environmental Impact Statement ("GEIS") to support an updated Waste Confidence Decision. On August 26, 2014, the NRC approved a final rule on the environmental effects of continued storage of spent nuclear fuel. The continued storage rule adopted the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations. As a result, those generic impacts do not need to be re-analyzed in the environmental reviews for individual licenses. Although Palo Verde had not been involved in any licensing actions affected by the D.C. Circuit's June 8, 2012, decision, the NRC lifted its suspension on final licensing actions on all nuclear power plant licenses and renewals that went into effect when the D.C. Circuit issued its June 2012 decision. The August 26th final rule has been subject to continuing legal challenges before the NRC and the Court of Appeals.

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). Based on current nuclear decommissioning trust asset balances, site specific decommissioning cost studies, anticipated future contributions to the decommissioning trusts, and return projections on the asset portfolios over the expected remaining operating

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life of the facility, we are on track to meet the current site specific decommissioning costs for Palo Verde at the time the units are expected to be decommissioned. See Note 19 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 10 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 severe damage.

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 the plant; and (2) enhancement of spent fuel pool instrumentation.

The NRC has issued a number of guidance documents regarding implementation of these requirements. Palo Verde has met the NRC's imposed deadlines for installation of equipment to address these requirements, but has minor additional work to perform in 2016. Palo Verde has spent approximately $125 million on capital enhancements as of December 31, 2015 (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 located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. APS completed a competitive solicitation process in which the Ocotillo project was evaluated against other alternatives. Consistent with the independent monitor's report, the Ocotillo project was selected as the best alternative. APS must finalize the permitting process before construction begins.

Solar Facilities

To date, APS has begun operation of 170 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.

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

In December 2014, the ACC voted that it had no objection to APS implementing a 10 MWdc (approximately 8.5 MWac) residential rooftop program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. Under this program, APS will own, operate and maintain approximately 1,500 residential systems. The program will target specific distribution feeders in an effort to maximize potential system benefits, while employing multiple "use cases" that will lead to a better understanding of the byproducts stemming from the multitude of complex technical interactions occurring as distributed energy resources are employed on the APS grid.

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 16.) 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 as of December 31, 2015 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 June 14, 2020	60
Exchange Agreement (b)	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 summer 2016	150
Demand Response Agreement (c)	Summer seasons through 2024	25
Renewable Energy (d)	Various	629

(a) 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.

(b) 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).

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

(d) 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 2015 peak one-hour demand on its electric system was recorded on August 15, 2015 at 7,031 MW, compared to the 2014 peak of 7,007 MW recorded on July 23, 2014. APS's reserve margin at the time of the 2015 peak demand, calculated using system load serving capacity, was 28%. 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 2015 reserve margin was 21%. APS anticipates the reserve margin for 2016 will be approximately 24%. Due to expiring purchase contracts and anticipated load growth, APS anticipates additional resources will be needed by 2017 in order to maintain its 15% planning reserve criteria.

Future Resources and Resource Plan

On May 8, 2015, the ACC acknowledged APS's 2014 resource plan. Under the ACC's resource planning rule, APS's next resource plan would be due on April 1, 2016. On September 16, 2015, however, the ACC issued an order extending the timeframe for all utilities, including APS, to file their next resource plans. The new schedule is designed to allow utilities additional time to consider the impacts of the Clean Power Plan and improve the resource planning process by allowing more time for input and review by the ACC and applicable stakeholders. Under the revised schedule, APS will file a preliminary resource plan on March 1, 2016 and a final resource plan on April 3, 2017. The revised schedule provides that the ACC will complete its review by February 1, 2018.

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and plans to seek recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its next retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($122 million as of December 31, 2015), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

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 6% of retail electric sales in 2016 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 RES renewable resource commitments. APS met its settlement commitment and RES target for 2015. A component of the RES is focused on stimulating development of distributed energy 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 6% in 2016. The following table summarizes the RES requirement standard (not including the additional commitment required by the 2009 Settlement Agreement) and its timing:

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	2016	2020	2025
RES as a % of retail electric sales	6%	10%	15%
Percent of RES to be supplied from distributed energy resources	30%	30%	30%

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 to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

Renewable Energy Portfolio. To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1,328 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1,278 MW are currently in operation and 50 MW are under contract for development or are under construction. Renewable resources in operation include 189 MW of facilities owned by APS, 629 MW of long-term purchased power agreements, and an estimated 427 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. In September 2015, APS completed construction of its 170 MW AZ Sun Program. APS has invested approximately $675 million in its AZ Sun Program. See Note 3 for additional details about the AZ Sun Program.

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.

	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	
Luke AFB	Glendale, AZ	2015		10	
Desert Star	Buckeye, AZ	2015		10	
Subtotal AZ Sun Program				170	
Multiple Facilities	AZ	Various		4	
Distributed Energy:					
APS Owned (a)	AZ	Various		15	9 (c)
Total APS Owned				189	9
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	—
Distributed Energy					

Solar (b)					
Third-party Owned	AZ	Various		427	41
Agreement 1	Bagdad, AZ	2011	25	15	
Agreement 2	AZ	2011-2012	20-21	18	
Total Distributed Energy				460	41
Total Renewable Portfolio				1,278	50

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(a) Includes Flagstaff Community Power Project, APS School and Government Program and APS Solar Partner Program.

(b) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in DC and is converted to AC for reporting purposes.

(c) This amount represents the Solar Partner Program consisting of approximately 1,500 APS-owned rooftop solar systems. We are in the process of installing these systems and expect all to be installed and operational by mid-2016, at which time the 9 MW will be considered "in operation" for purposes of this table.

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 standard will likely impact Arizona's future energy resource needs. (See Note 3 for energy efficiency and other demand side management obligations).

Government Awards

Through various DOE initiatives, the Federal government made a number of programs available for utilities to develop renewable resources, improve reliability and create jobs. In 2015, APS completed its work on a $3 million financial award for a high penetration photovoltaic generation study related to the Community Power Project in Flagstaff, Arizona.

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. 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 was 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 docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. A series of workshops in this docket were held in 2014 and another in February of 2015. No further workshops are scheduled and no actions were taken as a result of these workshops.

On January 28, 2016, an ACC Commissioner, Robert L. Burns, sent APS a Notice of Investigation pursuant to an Arizona statute that authorizes a Commissioner and his agents to inspect the accounts, books, papers and documents of any public service corporation, and examine under oath any officer, agent or employee of such corporation in relation to the business and affairs of the corporation. The Notice states that Commissioner Burns intends to investigate whether APS has used funds recoverable from ratepayers for political contributions, lobbying, or charitable donations purposes; whether APS's corporate affiliates have made contributions or donations under APS' brand name; and the degree to which APS and Pinnacle West are "intertwined" in terms of organization, management and operations. APS intends to cooperate with this investigation to the full extent that the matter is lawfully authorized, but cannot predict its timing or outcome.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS's transmission rates.) During 2015, approximately 5.2% 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 whether the 114th 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.

Regulatory Initiatives. In 2009, EPA determined that GHG emissions endanger public health and welfare. 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. APS will generally be required to consider the impact of GHG emissions as part of its traditional New Source Review ("NSR") analysis for new major sources and major modifications to existing plants.

On June 2, 2014, EPA issued two proposed rules to regulate GHG emissions from modified and reconstructed electric generating units ("EGUs") pursuant to Section 111(b) of the Clean Air Act and existing fossil fuel-fired power plants pursuant to Clean Air Act Section 111(d). On August 3, 2015, EPA finalized each of these carbon pollution standards for existing, new, modified, and reconstructed EGUs.

EPA’s final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

With respect to existing power plants, EPA’s recently finalized “Clean Power Plan” imposes state-specific goals or targets to achieve reductions in CO_2 emission rates from existing EGUs measured from a 2012 baseline. In a significant change from the proposed rule, EPA’s final performance standards apply directly to specific units based upon their fuel-type and configuration (i.e., coal- or oil-fired steam plants versus combined cycle natural gas plants). As such, each state’s goal is an emissions performance standard that reflects the fuel mix employed by the EGUs in operation in those states. The final rule provides guidelines to states to help develop their plans for meeting the interim (2022-2029) and final (2030 and beyond) emission performance standards, with three distinct compliance periods within that timeframe. States were originally required to submit their plans to EPA by September 2016, with an optional two-year extension provided to states establishing a need for additional time; however, it is expected that this timing will be impacted by the court-imposed stay described below.

ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, is presently working to develop a compliance plan for submittal to EPA. In addition to these on-going state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such delay.

With respect to our Arizona generating units, we are currently evaluating the range of compliance options available to ADEQ, including whether Arizona deploys a rate- or mass-based compliance plan. Based on the fuel-mix and location of our Arizona EGUs, and the significant investments we have made in renewable generation and demand-side energy efficiency, if ADEQ selects a rate-based compliance plan, we believe that we will be able to comply with the Clean Power Plan for our Arizona generating units in a manner that will not have material financial or operational impacts to the Company. On the other hand, if ADEQ selects a mass-based approach to compliance with the Clean Power Plan, our annual cost of compliance could be material. These costs could include costs to acquire mass-based compliance allowances.

As to our facilities on the Navajo Nation, EPA has yet to determine whether or to what extent EGUs on the Navajo Nation will be required to comply with the Clean Power Plan. EPA has proposed to determine that it is necessary or appropriate to impose a federal plan on the Navajo Nation for compliance with the Clean Power Plan. In response, we filed comments with EPA advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. If EPA reaches a determination that is consistent with our preferred approach for the Navajo Nation, we believe the Clean Power Plan will not have material financial or operational impacts on our operations within the Navajo Nation.

Alternatively, if EPA determines that a federal plan is necessary or appropriate for the Navajo Nation, and depending on our need for future operations at our EGUs located there, we may be unable to comply with the federal plan unless we acquire mass-based allowances or emission rate credits within established carbon trading markets, or curtail our operations. Subject to the uncertainties set forth below, and assuming that EPA establishes a federal plan for the Navajo Nation that requires carbon allowances or credits to be surrendered for plan compliance, it is possible we will be required to purchase some quantity of credits or allowances, the cost of which could be material.

Because ADEQ has not issued its plan for Arizona, and because we do not know whether EPA will decide to impose a plan or, if so, what that plan will require, there are a number of uncertainties associated with our potential cost exposure. These uncertainties include: whether judicial review will result in the Clean Power Plan being vacated in whole or in part or, if not, the extent of any resulting compliance deadline delays; whether any plan will be imposed for EGUs on the Navajo Nation; the future existence and liquidity of allowance or credit compliance trading markets; the applicability of existing contractual obligations with current and former owners of our participant-owned coal-fired EGUs; the type of federal or state compliance plan (either rate- or mass-based); whether or not the trading of allowances or credits will be authorized mechanisms for compliance with any final EPA or ADEQ plan; and how units that have been closed will be treated for allowance or credit allocation purposes.

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In the event that the incurrence of compliance costs is not economically viable or prudent for our operations in Arizona or on the Navajo Nation, or if we do not have the option of acquiring allowances to account for the emissions from our operations, we may explore other options, including reduced levels of output, as an alternative to purchasing allowances. Given these uncertainties, our analysis of the available compliance options remains on-going, and additional information or considerations may arise that change our expectations.

Company Response to Climate Change Initiatives. We have undertaken a number of initiatives that 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 or otherwise a part of this report.

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 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 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 Federal Implementation Plan ("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.

APS believes that EPA’s final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was

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closed on October 1, 2015), 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. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 (which occurred on October 1, 2015) and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015. On October 16, 2015, ADEQ issued the Cholla permit, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. APS is unable to predict when or whether APS's proposal may ultimately be approved by the EPA.

Four Corners. On August 6, 2012, EPA issued its final BART determination for Four Corners, which requires APS to install and operate SCR control technology on Units 4 and 5 by July 31, 2018. (APS retired Four Corners Units 1-3 on December 30, 2013.) APS estimates that its 63% share of the cost of these controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016. In December 2015, NTEC notified APS of its intention to exercise its option to acquire the 7% interest from APS. The cost of the controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

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. In addition, EPA proposed a "better than BART" alternative and solicited comment 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 and result in greater reasonable progress toward the national visibility goal than EPA's proposed BART determination. On July 28, 2014, EPA issued a final Navajo Plant BART rule approving the alternative stakeholder plan. 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. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe, and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this petition.

Mercury and other Hazardous Air Pollutants. In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excluding costs related to Cholla Unit 2, which was closed

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on October 1, 2015). 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, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court’s recent decision in Michigan vs. EPA reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of coal combustion residuals (“CCR”), such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (“RCRA”) and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent’s groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

Because the Subtitle D rule is self-implementing, the CCR standards apply directly to the regulated facility, and facilities are directly responsible for ensuring that their operations comply with the rule’s requirements. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million, and its share of incremental costs for Cholla is approximately $85 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million.

Effluent Limitation Guidelines. On September 30, 2015, EPA finalized revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired EGUs. EPA’s final regulation targets metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, “zero discharge” from fly ash and bottom ash handling, and impoundment for coal ash disposal leachate. Compliance with these limitations will be required in connection with National Pollution Discharge Elimination System ("NPDES") discharge permit renewals, which occur in five-year intervals, that arise between 2018 and 2023. Until a draft NPDES permit for Four Corners is proposed during that timeframe, we are uncertain what will be required to control these discharges in compliance with the finalized effluent limitations at that facility. Cholla and the Navajo Plant do not require NPDES permitting.

Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone national ambient air quality standards (“NAAQS”) at a level of 70 parts per billion (“ppb”). With ozone standards becoming more stringent, our fossil generation units will come under

increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA is expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. Depending on when EPA approves attainment designations for the Arizona and Navajo Nation jurisdictions in which our fossil generation units are located, revisions to SIPs and FIPs, respectively, implementing required controls to achieve the new 70 ppb standard are expected to be in place between 2020 and 2021. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

Clean Air Act Citizen Lawsuit. On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New 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 a First Amended Complaint adding claims for violations of the Clean Air Act's New Source Performance Standards ("NSPS") program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

The settlement requires installation of pollution control technology and implementation of other measures to reduce sulfur dioxide and nitrogen oxide emissions from the two Four Corners units, although installation of much of this equipment was already planned in order to comply with EPA's Regional Haze Rule requirements. The settlement also requires the Four Corners co-owners to pay a civil penalty of $1.5 million and spend $6.7 million for certain environmental mitigation projects to benefit the Navajo Nation. APS is responsible for 15 percent of these costs based on its ownership interest in the units at the time of the alleged violations, which does not result in a material impact on our financial position, results of operations or cash flows.

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. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these

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facilities may have contributed to groundwater contamination in this area. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

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.

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, SRP, 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.

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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 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.

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BUSINESS OF OTHER SUBSIDIARIES

Bright Canyon Energy

On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE will focus on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon continues to pursue transmission development opportunities in the western United States consistent with its strategy.

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, 2015, El Dorado had total assets of approximately $9 million. 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.

OTHER INFORMATION

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

	Principal Executive Office Address	Year of Incorporation	Approximate Number of Employees at December 31, 2015
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	93
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,309
BCE	400 North Fifth Street Phoenix, AZ 85004	2014	5
El Dorado	400 North Fifth Street Phoenix, AZ 85004	1983	—
Total			6,407

The APS number includes employees at jointly-owned generating facilities (approximately 2,830 employees) for which APS serves as the generating facility manager. Approximately 1,673 APS employees are union employees, represented by the International Brotherhood of Electrical Workers ("IBEW") or the United Security Professionals of America ("USPA"). APS concluded negotiations with IBEW representatives over the new collective bargaining agreement in April 2015, and the new agreement is in place until March 31, 2018. The contract provides an average wage increase of 2.0% for the first year, 2.25% for the second year and 3.0% for the third year. The Company concluded negotiations with the USPA over the terms of a new collective bargaining agreement in May of 2014, and the new agreement is in place until May 31, 2017.

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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, including in some cases how court challenges to these regulatory decisions are resolved. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify otherwise final orders under certain circumstances.

APS is currently pursuing certain activities, such as microgrid investments and construction of renewable facilities intended for specific customers. To date, APS has not received regulatory assurance of cost recovery for such investments. As APS engages in these activities, we will have to demonstrate to regulators that these investments are both prudent and useful in providing electric service to customers.

The ACC must also approve APS’s issuance of securities and any significant transfer or encumbrance 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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In a recent appellate challenge to an ACC rate decision regarding a water company (referred to in Note 3 as "SIB"), the Arizona Court of Appeals considered the question of how the ACC should determine the “fair value” of a utility’s property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors or surcharges outside of a rate case. The Court of Appeals reversed the ACC’s method of finding fair value in that case, and raised questions concerning the relationship between fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC’s petition to the Arizona Supreme Court for review of the Court of Appeals’ decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS’s ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

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.

On January 28, 2016, an ACC Commissioner, Robert L. Burns, sent APS a Notice of Investigation pursuant to an Arizona statute that authorizes a Commissioner and his agents to inspect the accounts, books, papers and documents of any public service corporation, and examine under oath any officer, agent or employee of such corporation in relation to the business and affairs of the corporation. The Notice states that Commissioner Burns intends to investigate whether APS has used funds recoverable from ratepayers for political contributions, lobbying, or charitable donations purposes; whether APS’s corporate affiliates have made contributions or donations under APS’ brand name; and the degree to which APS and Pinnacle West are “intertwined” in terms of organization, management and operations. APS intends to cooperate with this investigation to the full extent that the matter is lawfully authorized, but cannot predict its timing or outcome.

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 analyzed information from the Japan incident and develop action plans for U.S. nuclear power plants. Additionally, the NRC performed 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

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should promulgate additional regulations and possibly make more fundamental changes to the NRC's system of regulation. As a result of the Fukushima event, 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 $0.5 million for capital enhancements to the plant over the next year in addition to the approximate $125 million that has already been spent on capital enhancements as of December 31, 2015 (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.
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, Cholla and the Navajo Plant. Pursuant to these rules, 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.

Coal Ash. In December 2014, EPA issued final regulations governing the handling and disposal of CCR, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners and in a dry landfill storage area at the Navajo Plant. To the extent the rule requires the closure or modification of these CCR units or the construction of new CCR units beyond what we currently anticipate, APS would incur significant additional costs for CCR disposal.

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Ozone National Ambient Air Quality Standards. In 2015, EPA finalized revisions to the national ambient air quality standards for nitrogen oxides, which set new, more stringent standards intended to protect human health and human welfare. Depending on the stringency of the final standards and the implementation requirements, APS may be required to invest in new pollution control technologies and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas.

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 coupled with trends in natural gas and coal prices, 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 effects, and potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG emissions.

Concern over climate change has led to significant legislative and regulatory efforts to limit CO2, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions.
Financial Risks - Greenhouse Gas Regulation and the Clean Power Plan. In 2015, EPA finalized a rule to limit carbon dioxide emissions from existing power plants. The implementation of this rule within the jurisdictions where APS operates could result in a shift in in-state generation from coal to natural gas and renewable generation. Such a substantial change in APS's generation portfolio could require additional capital investments and increased operating costs, and thus have a significant financial impact on the Company. See Note 10 for additional risks and uncertainties resulting from the Clean Power Plan.
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 would 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. On November 25, 2015, the ACC issued an order approving a request by several AG-1 customers and suppliers to extend the term of the program from July 1, 2016 to the conclusion of APS's next general rate case. The order also authorized APS to defer for future recovery unmitigated unrecovered costs attributable to the program at 90% of the first $10 million per year and at 100% of amounts above $10 million per year.

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. The use of such products by customers within our territory results in some level of competition. APS cannot predict when, and the extent to which, additional service providers will enter APS’s service territory, increasing the level of competition in the market.

Proposals to enable or support retail electric competition are made from time to time in legislative or other forums in Arizona. We cannot predict future regulatory or legislative action that might result in increased competition.

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 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

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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 2013 through 2015, APS's retail customer growth averaged 1.3% per year. We currently expect annual customer growth to average in the range of 2.0-3.0% for 2016 through 2018 based on our assessment of modestly improving economic conditions in Arizona. For the three years 2013 through 2015 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 in the range of 0.5-1.5% during 2016 through 2018, 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, usage patterns and energy conservation, impacts of energy efficiency programs and growth in distributed generation, and responses to retail price changes. 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.
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.

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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.

We are subject to cybersecurity 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. A security breach of our information systems such as theft or the inappropriate release of certain types of information, including 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.

We are subject to laws and rules issued by multiple government agencies concerning safeguarding and maintaining the confidentiality of our security, customer and business information. One of these agencies, NERC, has issued comprehensive regulations and standards surrounding the security of our operating systems, and is continually in the process of developing updated and additional requirements with which the utility industry must comply. The increasing promulgation of NERC rules and standards will increase our compliance costs and our exposure to the potential risk of violations of the standards.

We have experienced, and expect to continue to experience, these types of threats and attempted intrusions. The implementation of additional security measures could increase costs and have a material adverse impact on our financial results. We have 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. 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.

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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 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 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 19% 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 $16.6 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 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.

Alternative energy technologies that produce power or reduce power consumption or emissions are being developed and commercialized, including renewable technologies such as photovoltaic (solar) cells, customer-sited generation, energy storage (batteries), and efficiency technologies. Advances in technology and equipment/appliance efficiency could reduce the demand for supply from conventional generation, which could adversely affect APS's business.

APS continues to pursue and implement advanced grid technologies, including transmission and distribution system technologies and 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 established or mature as APS's existing technologies and equipment. Widespread installation and acceptance of new 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.

Deployment of renewable energy technologies is expected to continue across the western states and result in a larger portion of the overall energy production coming from these sources. These trends, which have benefited from historical and continuing government subsidies for certain technologies, have the potential to put downward pressure on wholesale power prices throughout the western states which could make APS's existing generating facilities less economical and impact their operational patterns and long-term viability.

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 maturing, with approximately 36% of employees eligible to retire by the end of 2018. 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.

FINANCIAL RISKS

Financial market disruptions or new 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 cause our cost of borrowing to increase generally, and/or otherwise adversely affect our ability to access these financial markets.

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In addition, the credit commitments of our lenders under our bank facilities may not be satisfied or continued beyond current commitment periods for a variety of reasons, including new rules and regulations, periods of financial distress or liquidity issues affecting our lenders or financial markets, which could materially adversely affect the adequacy of our liquidity sources and the cost of maintaining these sources.

Changes in economic conditions, monetary policy, financial regulation 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, whether as a result of these factors or otherwise, 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 investment in our business or other purposes.

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 could 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 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

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postretirement benefit costs, cash contributions, regulatory assets, and charges to OCI. Changes in demographics, including increased number of retirements or changes in life expectancy and changes in other actuarial assumptions, may also result in similar impacts. 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. Most of the Patient Protection and Affordable Care Act provisions have been implemented; however, costs and other 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.

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;

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- 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.

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 2015 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 (d)	2			Coal	Base Load	387
Navajo (e)	3	14	%	Coal	Base Load	315
Ocotillo	2			Gas	Peaking	220
Total Steam						1,892
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
Gila Bend	1			Solar	As Available	32
Hyder II	1			Solar	As Available	14
Foothills	1			Solar	As Available	35
Luke AFB	1			Solar	As Available	10
Desert Star	1			Solar	As Available	10
APS Owned Distributed Energy				Solar	As Available	15
Multiple facilities				Solar	As Available	4
Total Solar						189
Total Capacity						6,186

(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 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.

(d) Cholla Unit 2's last day of service was on October 1, 2015.

(e) 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 6,070 pole miles of overhead lines and approximately 49 miles of underground lines, 5,847 miles of which are located in Arizona. APS’s distribution facilities consist of approximately 11,077 miles of overhead lines and approximately 18,071 miles of underground primary cable, all of which are located in Arizona. APS distribution facilities reflect an actual net gain of 169 miles in 2015. 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, 2015:

	Percent Owned (Weighted-Average)	
Morgan — Pinnacle Peak System	64.6	%
Palo Verde — Estrella 500kV System	50.0	%
Round Valley System	50.0	%
ANPP 500kV System	33.4	%
Navajo Southern System	22.7	%
Four Corners Switchyards	49.8	%
Palo Verde — Yuma 500kV System	19.3	%
Phoenix — Mead System	17.1	%
Palo Verde — Morgan System	87.7	%
Hassayampa — North Gila System	80.0	%
Cholla 500 Switchyard	85.7	%
Saguaro 500 Switchyard	75.0	%

Expansion. Each year APS prepares and files with the ACC a ten-year transmission plan. In APS’s 2015 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 Palo Verde to Morgan System includes Palo Verde-Delaney-Sun Valley-Morgan. The project consists of four phases. The first phase, Morgan to Pinnacle Peak 500kV, is currently in-service. The second

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and third phases, Delaney to Palo Verde 500kV and Delaney to Sun Valley 500kV, are under construction and are expected to be energized by May 2016. The fourth phase, Morgan to Sun Valley 500kV, has been permitted and is in 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 2015 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. The North Gila to Hassayampa line went into service in May 2015.

Physical Security Standards. On July 14, 2015, FERC approved version 2 of the proposed Physical Security Reliability Standard CIP-014 (CIP-014-2). As a result, CIP-014-2, the Physical Security Reliability Standard that requires transmission owners and operators to protect those critical transmission stations and substations and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack, could result in widespread instability, uncontrolled separation or cascading within an interconnection, became effective on October 2, 2015, triggering a series of staggered, but interdependent obligations for APS. As required by the Physical Security Reliability Standard, APS determined its critical transmission stations and substations and associated primary control centers that will be required to comply with the standard by October 2, 2015. However, as contemplated under CIP-014-2, this verification has triggered additional requirements and obligations within the Physical Security Reliability Standard that are not yet due to be completed. These remaining obligations, which consist of a risk evaluation and development and verification of a physical security plan, are due to be completed by the end the third quarter of 2016. Until APS has completed all required activities under the Physical Security Reliability Standard, we cannot predict the extent of any financial or operational impacts on APS.

NERC Critical Infrastructure Protection Requirements. In 2014, APS initiated a comprehensive project to ensure compliance with Version 5 of NERC's Critical Infrastructure Protection Requirements (CIP V.5) which will become effective April 1, 2016. APS will be incurring incremental capital expenditures through 2017 associated with the CIP V.5 compliance implementation project estimated to be approximately $52 million.

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 were scheduled to expire in 2016. In March, 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. The effectiveness of the lease amendment also required the approval of the DOI, as did the related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015. The record of decision provides the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015.

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

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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 certain 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 10 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 19, 2016, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Donald E. Brandt	61	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
Robert S. Bement	60	Senior Vice President, Site Operations, PVNGS, of APS	2011-Present
Denise R. Danner	60	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
Patrick Dinkel	52	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
Randall K. Edington	62	Executive Vice President and Chief Nuclear Officer, PVNGS, of APS	2007-Present
David P. Falck	62	Executive Vice President and General Counsel of Pinnacle West and APS	2009-Present
		Secretary of Pinnacle West and APS	2009-2012
Daniel T. Froetscher	54	Senior Vice President, Transmission, Distribution & Customers of APS	2014-Present
		Vice President, Energy Delivery of APS	2008-2014
Barbara M. Gomez	61	Vice President, Human Resources of APS	2014-Present
		Vice President, Chief Procurement Officer of APS	2013-2014
		Vice President, Supply Chain Management of APS	2010-2013
Jeffrey B. Guldner	50	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	58	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
John S. Hatfield	50	Vice President, Communications of APS	2010-Present
Tammy D. McLeod	54	Vice President, Resource Management of APS	2014-Present
		Vice President and Chief Customer Officer of APS	2007-2014
Lee R. Nickloy	49	Vice President and Treasurer of Pinnacle West and APS	2010-Present
Mark A. Schiavoni	60	Executive Vice President and Chief Operating Officer of APS	2014-Present
		Executive Vice President, Operations of APS	2012-2014
		Senior Vice President, Fossil Operations of APS	2009-2012

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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 12, 2016, Pinnacle West's common stock was held of record by approximately 20,570 shareholders.

QUARTERLY STOCK PRICES AND DIVIDENDS PAID PER SHARE
STOCK SYMBOL: PNW

2015	High	Low	Close	Dividends Per Share
1st Quarter	$73.31	$61.53	$63.75	$0.595
2nd Quarter	64.95	56.01	56.89	0.595
3rd Quarter	65.23	56.77	64.14	0.595
4th Quarter	67.02	60.70	64.48	0.625

2014	High	Low	Close	Dividends Per Share
1st Quarter	$55.99	$51.15	$54.66	$0.5675
2nd Quarter	58.06	53.71	57.84	0.5675
3rd Quarter	57.95	52.13	54.64	0.5675
4th Quarter	71.11	54.59	68.31	0.595

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 2015 and 2014.

Common Stock Dividends
(Dollars in Thousands)

Quarter	2015	2014
1st Quarter	$65,800	$62,500
2nd Quarter	65,900	62,600
3rd Quarter	65,900	62,700
4th Quarter	69,300	65,800

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, 2015, 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 2015.

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, 2015	61,471	$65.74	—	—
November 1 – November 30, 2015	—	—	—	—
December 1 – December 31, 2015	—	—	—	—
Total	61,471	$65.74	—	—

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

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ITEM 6. SELECTED FINANCIAL DATA
PINNACLE WEST CAPITAL CORPORATION – CONSOLIDATED

The selected data presented below as of and for the years ended December 31, 2015, 2014, 2013, 2012 and 2011 are derived from the Consolidated Financial Statements. The data should be read in connection with the Consolidated Financial Statements including the related notes included in Item 8 of this Form 10-K.

	2015	2014	2013	2012	2011
	(dollars in thousands, except per share amounts)				
OPERATING RESULTS					
Operating revenues	$3,495,443	$3,491,632	$3,454,628	$3,301,804	$3,241,379
Income from continuing operations	$456,190	$423,696	$439,966	$418,993	$355,634
Income (loss) from discontinued operations – net of income taxes	—	—	—	(5,829)	11,306
Net income	456,190	423,696	439,966	413,164	366,940
Less: Net income attributable to noncontrolling interests	18,933	26,101	33,892	31,622	27,467
Net income attributable to common shareholders	$437,257	$397,595	$406,074	$381,542	$339,473
COMMON STOCK DATA					
Book value per share – year-end	$41.30	$39.50	$38.07	$36.20	$34.98
Earnings per weighted-average common share outstanding:					
Continuing operations attributable to common shareholders – basic	$3.94	$3.59	$3.69	$3.54	$3.01
Net income attributable to common shareholders – basic	$3.94	$3.59	$3.69	$3.48	$3.11
Continuing operations attributable to common shareholders – diluted	$3.92	$3.58	$3.66	$3.50	$2.99
Net income attributable to common shareholders – diluted	$3.92	$3.58	$3.66	$3.45	$3.09
Dividends declared per share	$2.44	$2.33	$2.23	$2.67	$2.10
Weighted-average common shares outstanding – basic	111,025,944	110,626,101	109,984,160	109,510,296	109,052,840
Weighted-average common shares outstanding – diluted	111,552,130	111,178,141	110,805,943	110,527,311	109,864,243
BALANCE SHEET DATA (a)					
Total assets	$15,028,258	$14,288,890	$13,486,826	$13,357,123	$13,089,837
Liabilities and equity:					
Current liabilities	$1,442,317	$1,559,143	$1,618,644	$1,083,542	$1,342,705
Long-term debt less current maturities	3,462,391	3,006,573	2,774,605	3,176,596	2,997,873
Deferred credits and other	5,404,093	5,204,072	4,753,117	4,994,696	4,818,673
Total liabilities	10,308,801	9,769,788	9,146,366	9,254,834	9,159,251
Total equity	4,719,457	4,519,102	4,340,460	4,102,289	3,930,586
Total liabilities and equity	$15,028,258	$14,288,890	$13,486,826	$13,357,123	$13,089,837

(a) During the fourth quarter of 2015, we adopted the new accounting standard related to balance sheet presentation of debt issuance costs. See further discussion in Note 2.

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SELECTED FINANCIAL DATA
ARIZONA PUBLIC SERVICE COMPANY – CONSOLIDATED

	2015	2014	2013	2012	2011
	(dollars in thousands)				
OPERATING RESULTS					
Electric operating revenues	$3,492,357	$3,488,946	$3,451,251	$3,293,489	$3,237,241
Fuel and purchased power costs	1,101,298	1,179,829	1,095,709	994,790	1,009,464
Other operating expenses	1,779,075	1,716,325	1,733,677	1,693,170	1,673,394
Operating income	611,984	592,792	621,865	605,529	554,383
Other income	33,332	36,358	20,797	16,358	24,974
Interest expense — net of allowance for borrowed funds	176,109	181,830	183,801	194,777	215,584
Net income	469,207	447,320	458,861	427,110	363,773
Less: Net income attributable to noncontrolling interests	18,933	26,101	33,892	31,613	27,524
Net income attributable to common shareholder	$450,274	$421,219	$424,969	$395,497	$336,249
BALANCE SHEET DATA (a)					
Total assets	$14,982,182	$14,190,362	$13,359,517	$13,220,050	$13,011,056
Liabilities and equity:					
Total equity	$4,814,794	$4,629,852	$4,454,874	$4,222,483	$4,051,406
Long-term debt less current maturities	3,337,391	2,881,573	2,649,604	3,051,596	2,872,872
Total capitalization	8,152,185	7,511,425	7,104,478	7,274,079	6,924,278
Current liabilities	1,424,708	1,532,464	1,580,847	1,043,087	1,322,714
Deferred credits and other	5,405,289	5,146,473	4,674,192	4,902,884	4,764,064
Total liabilities and equity	$14,982,182	$14,190,362	$13,359,517	$13,220,050	$13,011,056

(a) During the fourth quarter of 2015, we adopted the new accounting standard related to balance sheet presentation of debt issuance costs. See further discussion in Note 2.

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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 currently accounts for essentially all of our revenues and earnings.

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 address lessons learned from the Fukushima events. The independent assessment, named the "Near Term Task Force," recommended a number of proposed enhancements to U.S. commercial nuclear power plant equipment and emergency plans. The NRC has directed nuclear power plants to begin implementing some of the Near Term Task Force's recommendations. To implement these recommendations, Palo Verde expects to spend approximately $0.5 million for capital enhancements to the plant through 2016 in addition to the approximate $125 million that has already been spent on capital enhancements as of December 31, 2015 (APS's share is 29.1%).

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. On June 2, 2014, EPA proposed a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"), and EPA finalized its proposal on August 3, 2015.

EPA's nationwide CO_2 emissions reduction goal is 32% below 2005 emission levels. As finalized for the state of Arizona and the Navajo Nation, compliance with the Clean Power Plan could involve a shift in generation from coal to natural gas and renewable generation. Until implementation plans for these jurisdictions are finalized, we are unable to determine the actual impacts to APS. APS continually analyzes its long-range capital management plans to assess the potential effects of these changes, 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 continue participation in such plants.

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Cholla

On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 10 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long term than the benefits that would have resulted from adding emissions control equipment. APS closed Unit 2 on October 1, 2015.

Four Corners

Asset Purchase Agreement and Coal Supply Matters. On December 30, 2013, APS purchased SCE’s 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. 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 23, 2014, the ACC approved rate adjustments related to APS’s acquisition of SCE’s interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustments was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed below, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

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 for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031. 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. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso’s 7% interest in each of Units 4 and 5 of Four Corners. The cash purchase price, which will be subject to certain adjustments at closing, is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016.

When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. On December 29, 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

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 required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record

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of decision on July 17, 2015. The record of decision provided the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015. On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with the environmental review described above were not in accordance with applicable law. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. APS completed a competitive solicitation process in which the Ocotillo project was evaluated against other alternatives. Consistent with the independent monitor’s report, the Ocotillo project was selected as the best alternative. APS must finalize the permitting process before construction can begin.

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 below includes new APS transmission projects through 2018, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand advanced 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 6% of retail electric sales in 2016 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 RES renewable resource commitments. APS met its settlement commitment and RES target for 2015. A component of the RES targets development of distributed energy systems.

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 to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

On July 1, 2014, APS filed its 2015 RES implementation plan and proposed a RES budget of approximately $154 million. On December 31, 2014, the ACC issued a decision approving the 2015 RES implementation plan with minor modifications, including reducing the requested budget to approximately $152 million.

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On July 1, 2015, APS filed its 2016 RES implementation plan and proposed a RES budget of approximately $148 million. On January 12, 2016, the ACC approved APS's plan and requested budget.

APS has developed owned solar resources through the ACC-approved AZ Sun Program. APS has invested approximately $675 million in its AZ Sun Program. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the project to the electric grid.

In accordance with the ACC's decision on the 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 MW of APS-owned utility scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of utility scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

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 Energy Efficiency Standard 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 standard became effective on January 1, 2011.

On June 1, 2012, APS filed its 2013 DSM Plan. In 2013, the standards required 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.

On March 11, 2014, the ACC issued an order approving APS's 2013 DSM Plan. The ACC approved a budget of $68.9 million for each of 2013 and 2014. The ACC also approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also approved that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standard, however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its Lost Fixed Cost Recovery mechanism.

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. The DSM Plan also proposed a reduction in the DSMAC of approximately 12%.

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Electric Energy Efficiency. On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 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.

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Utility Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. A formal rulemaking has not been initiated and there has been no additional action on the draft to date.

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.

On January 29, 2016, APS filed a NOI informing the ACC that APS intends to submit a rate case application in June 2016 using an adjusted test year ending December 31, 2015. The NOI provides an overview of the key issues APS expects to address in its formal request such as rate design changes (residential, commercial and industrial), a decoupling mechanism, permission to defer for potential future recovery costs associated with the Company's Ocotillo Modernization Project, permission to defer for potential future recovery costs associated with environmental standards compliance, inclusion of post-test year plant and modifications to certain adjustor mechanisms, among other items. In its rate application, APS will request that its proposed pricing changes take effect in July 2017. APS is still developing the exact amount of the request.

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 alternate arrangement under which SCE would 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. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

Net Metering. On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. 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 electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

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 electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing has been scheduled to commence in April 2016. APS cannot predict the outcome of this proceeding.

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS has also requested intervention in the upcoming Tucson Electric Power Company rate case. The outcomes of these proceedings will not directly impact our financial position.

Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB"). In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC's petition to the Arizona Supreme Court for review of the Court of Appeals' decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS's ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

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.

Other Subsidiaries.

Bright Canyon Energy. On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE will focus on new growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE's first initiative is a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent transmission opportunities within the eleven states that comprise the Western Electricity Coordinating Council, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners' utility affiliates. TransCanyon continues to pursue transmission development opportunities in the western United States consistent with its strategy.

El Dorado. The operations of El Dorado 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 2013 through 2015, 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 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 customers in APS's service territory increased 1.2% for the year ended December 31, 2015 compared with the prior year. For the three years 2013 through 2015, APS's customer growth averaged 1.3% per year. We currently expect annual customer growth to average in the range of 2.0-3.0% for 2016 through 2018 based on our assessment of modestly improving economic conditions in Arizona. Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.7% for the year ended December 31, 2015 compared with the prior year, reflecting the effects of improving economic conditions and customer growth, partially offset by customer conservation and energy efficiency and distributed renewable generation initiatives. For the three years 2013 through 2015, 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 in the range of 0.5-1.5% during 2016 through 2018, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy 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 projections 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

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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. On September 30, 2014, Pinnacle West announced plan design changes to the group life and medical postretirement benefit plan, which reduced net periodic benefit costs. See Note 7.

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 distribution facilities), and changes in depreciation and amortization rates. See "Capital Expenditures" below for information regarding the planned additions to our facilities. See Note 3 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 11.0% of the assessed value for 2015, 10.7% for 2014 and 10.5% for 2013. 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 – 2015 compared with 2014.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2015 was $437 million, compared with $398 million for the prior year. The results reflect an increase of approximately $34 million for the regulated electricity segment primarily due to the Four Corners-related rate change, lower operations and maintenance expenses, and higher retail sales due to customer growth and changes in customer usage patterns and related pricing, partially offset by higher depreciation and amortization. The all other segment's income was higher by $5 million primarily related to El Dorado's investment losses in 2014.

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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, 2015	2014	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$2,391	$2,309	$82
Operations and maintenance	(868)	(908)	40
Depreciation and amortization	(494)	(417)	(77)
Taxes other than income taxes	(172)	(172)	—
All other income and expenses, net	19	28	(9)
Interest charges, net of allowance for borrowed funds used during construction	(179)	(185)	6
Income taxes	(239)	(224)	(15)
Less income related to noncontrolling interests (Note 18)	(19)	(26)	7
Regulated electricity segment income	439	405	34
All other	(2)	(7)	5
Net Income Attributable to Common Shareholders	$437	$398	$39

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $82 million higher for the year ended December 31, 2015 compared with the prior year. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Four Corners-related rate change	$56	$—	$56
Higher retail sales due to customer growth and changes in customer usage patterns and related pricing	25	6	19
Lost fixed cost recovery	12	—	12
Effects of weather	16	6	10
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(69)	(68)	(1)
Changes in long-term wholesale contracted sales	(40)	(25)	(15)
Miscellaneous items, net	3	2	1
Total	$3	$(79)	$82

Operations and maintenance. Operations and maintenance expenses decreased $40 million for the year ended December 31, 2015 compared with the prior year primarily because of:

- A decrease of $21 million for employee benefit costs;

- A decrease of $14 million in fossil generation costs primarily related to lower planned outage costs;
- A decrease of $13 million for costs related to corporate support;
- A decrease of $8 million related to costs for demand-side management, renewable energy and similar regulatory programs, which is partially offset in operating revenues and purchased power;
- An increase of $9 million related to higher nuclear generation costs;
- An increase of $6 million in customer service costs including costs related to a new customer information system; and
- An increase of $1 million related to other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $77 million higher for the year ended December 31, 2015 compared with the prior year primarily related to:

- An increase of $34 million related to the absence of 2014 Four Corners cost deferrals and the related 2015 amortization;
- An increase of $16 million related to the Four Corners acquisition adjustment;
- An increase of $20 million due to increased plant in service;
- An increase of $10 million related to the regulatory treatment of the Palo Verde sale leaseback, which is offset in noncontrolling interests; and
- A decrease of $3 million due to other miscellaneous factors.

All other income and expenses, net. All other income and expenses, net, were $9 million lower for the year ended December 31, 2015 compared with the prior year primarily due to the return on the Four Corners acquisition in 2014.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, decreased $6 million for the year ended December 31, 2015 compared with the prior year, primarily because of lower interest rates on our debt in the current year.

Income taxes. Income taxes were $15 million higher for the year ended December 31, 2015 compared with the prior year primarily due to the effects of higher pretax income in the current year.

Operating Results – 2014 compared with 2013.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2014 was $398 million, compared with $406 million for the prior year. The results reflect a decrease of approximately $4 million for the regulated electricity segment primarily due to higher fossil generation costs, lower retail sales due to the effects of weather, higher property taxes, and lower retail transmission revenues. These

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negative factors were partially offset by lower operations and maintenance expenses related to lower employee benefit costs, higher other income, and increased revenues for lost fixed cost recovery. All other segment's income was lower by $4 million primarily related to El Dorado's investment losses.

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

	Year Ended December 31, 2014	2013	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$2,309	$2,356	$(47)
Operations and maintenance	(908)	(925)	17
Depreciation and amortization	(417)	(416)	(1)
Taxes other than income taxes	(172)	(164)	(8)
All other income and expenses, net	28	11	17
Interest charges, net of allowance for borrowed funds used during construction	(185)	(187)	2
Income taxes	(224)	(232)	8
Less income related to noncontrolling interests (Note 18)	(26)	(34)	8
Regulated electricity segment income	405	409	(4)
All other	(7)	(3)	(4)
Net Income Attributable to Common Shareholders	$398	$406	$(8)

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $47 million lower for the year ended December 31, 2014 compared with the prior year. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Effects of weather	$(45)	$(16)	$(29)
Lower demand side management regulatory surcharges, offset by renewable energy regulatory surcharges and purchased power	—	20	(20)
Lower retail transmission revenues	(7)	—	(7)
Lower retail sales due to changes in customer usage patterns and related pricing, partially offset by customer growth	(4)	—	(4)
Higher net fuel and purchased power costs, including related deferrals and higher off-system sales margins	78	79	(1)
Lost fixed cost recovery	12	—	12
Miscellaneous items, net	3	1	2
Total	$37	$84	$(47)

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Operations and maintenance. Operations and maintenance expenses decreased $17 million for the year ended December 31, 2014 compared with the prior year primarily because of:

- A decrease of $33 million related to costs for demand-side management, renewable energy and similar regulatory programs, which were partially offset in operating revenues and purchased power;
- A decrease of $20 million related to lower employee benefit costs;
- An increase of $33 million in generation costs, primarily related to an increased ownership share in Four Corners, a portion of which is deferred in depreciation and amortization, and higher fossil maintenance costs; and
- An increase of $3 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $1 million higher for the year ended December 31, 2014 compared with the prior year primarily related to higher plant balances of approximately $23 million, partially offset by higher Four Corners cost deferrals in the current year of approximately $22 million.

Taxes other than income taxes. Taxes other than income taxes were $8 million higher for the year ended December 31, 2014 compared with the prior year primarily due to higher property tax rates and higher plant balances.

All other income and expenses, net. All other income and expenses, net, were $17 million higher for the year ended December 31, 2014 compared with the prior year due to the debt return on the Four Corners acquisition, an increase in the allowance for equity funds used during construction due to higher balances, and other non-operating income.

Income taxes. Income taxes were $8 million lower for the year ended December 31, 2014 compared with the prior year primarily due to the effects of lower pretax income in the current year.

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 related ACC order, the common equity ratio is defined as 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, 2015, APS's common equity ratio, as defined, was 55%. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.6 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.4 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.

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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.

Many of APS's current capital expenditure projects qualify for bonus depreciation. On December 18, 2015, President Obama signed into law the Consolidated Appropriations Act, 2016 (H.R. 2029) which combined the tax and government funding bills (The Protecting Americans from Tax Hikes Act and Omnibus Bill) containing an extension of bonus depreciation through 2019. Enactment of this legislation is expected to generate approximately $375-$425 million of cash tax benefits over the next three years, which is expected to be fully realized by APS and Pinnacle West Consolidated during this time frame. The cash generated by the extension of bonus depreciation is an acceleration of the tax benefits that APS would have otherwise received over 20 years. At Pinnacle West Consolidated, the extension of bonus depreciation will, in turn, delay until 2019 full cash realization of approximately $82 million of currently unrealized Investment Tax Credits, which are recorded as a deferred tax asset on the Consolidated Balance Sheet as of December 31, 2015.

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, 2015, 2014 and 2013 (dollars in millions):

Pinnacle West Consolidated

	2015	2014	2013
Net cash flow provided by operating activities	$1,094	$1,100	$1,153
Net cash flow used for investing activities	(1,066)	(923)	(1,009)
Net cash flow provided by (used for) financing activities	4	(179)	(161)
Net increase (decrease) in cash and cash equivalents	$32	$(2)	$(17)

Arizona Public Service Company

	2015	2014	2013
Net cash flow provided by operating activities	$1,100	$1,124	$1,194
Net cash flow used for investing activities	(1,060)	(922)	(1,009)
Net cash flow used for financing activities	(22)	(201)	(185)
Net increase in cash and cash equivalents	$18	$1	$—

Operating Cash Flows

2015 Compared with 2014. Pinnacle West's consolidated net cash provided by operating activities was $1,094 million in 2015 compared to $1,100 million in 2014, a decrease of $6 million in net cash provided. The decrease is primarily related to a $135 million income tax refund received in the first quarter of 2014, which is partially offset by a $48 million change in cash collateral posted, and other changes in working capital including increased cash receipts for the Four Corners-related rate change of $56 million.

2014 Compared with 2013. Pinnacle West's consolidated net cash provided by operating activities was $1,100 million in 2014 compared to $1,153 million in 2013, a decrease of $53 million in net cash provided. The decrease is primarily related to $99 million in higher fuel and purchased power costs, a $39 million increase in cash collateral posted, $34 million of higher pension contributions in 2014, and other changes in working capital. The decrease is partially offset by a $121 million increase in income tax refunds net of payments (primarily related to a $135 million income tax refund received in the first quarter of 2014). APS's

operating cash flows included income tax refunds of approximately $86 million in 2014 compared with payments of $8 million in 2013.

Retirement plans and other postretirement benefits. 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 116% funded as of January 1, 2015 and is estimated to be approximately 116% funded as of January 1, 2016. Under GAAP, the qualified pension plan was 89% funded as of January 1, 2015 and is estimated to be approximately 88% funded as of January 1, 2016. See Note 7 for additional details. 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 $100 million in 2015, $175 million in 2014, and $141 million in 2013. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2016-2018 period. With regard to our contributions to our other postretirement benefit plans, we made a contribution of approximately $1 million in 2015, $1 million in 2014, and $14 million in 2013. We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans.

Investing Cash Flows

2015 Compared with 2014. Pinnacle West's consolidated net cash used for investing activities was $1,066 million in 2015, compared to $923 million in 2014, an increase of $143 million in net cash used primarily related to increased capital expenditures.

2014 Compared with 2013. Pinnacle West's consolidated net cash used for investing activities was $923 million in 2014, compared to $1,009 million in 2013, a decrease of $86 million in net cash used. The decrease 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 in 2013, partially offset by an increase of approximately $123 million in other capital expenditures.

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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,		
	2016	2017	2018
APS			
Generation:			
Nuclear Fuel	$81	$78	$81
Renewables	110	1	1
Environmental	235	199	130
New Gas Generation	77	237	112
Other Generation	134	133	222
Distribution	357	345	376
Transmission	123	210	120
Other (a)	88	82	82
Total APS	$1,205	$1,285	$1,124

(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 capital expenditures include a planned utility-scale solar facility, which is subject to regulatory approval. 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 we have proposed a compromise strategy to EPA, which, if approved, would allow us to avoid expenditures related to environmental control equipment. The portion of estimated costs for 2016 through 2018 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. Costs related to the Navajo Plant's compliance with the regional haze rules are not included in the table above, as they are expected to be incurred post-2018. The portion of estimated costs for 2016 through 2018 for incremental costs to comply with the CCR rule for Four Corners and Cholla have also been included in the table above.

On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. On December 29, 2015, NTEC notified APS of its intent to exercise its option to purchase the 7% interest. The table above does not include capital expenditures related to El Paso's 7% interest in Four Corners Units 4 and 5 of $27 million in 2016 and $20 million in 2017. 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.

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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

2015 Compared with 2014. Pinnacle West's consolidated net cash provided by financing activities was $4 million in 2015, compared to $179 million net cash used in 2014, an increase of $183 million in net cash provided. The increase in net cash provided by financing activities is primarily due to $237 million lower repayments of long-term debt and $111 million higher issuances of long-term debt (see below), partially offset by a $142 million net change in short-term borrowings.

2014 Compared with 2013. Pinnacle West's consolidated net cash used for financing activities was $179 million in 2014, compared to $161 million in 2013, an increase of $18 million in net cash used. The increase in net cash used for financing activities is primarily due to $530 million in higher repayments of long-term debt, a $67 million net reduction in funds received through short-term borrowings, and $11 million in higher dividend payments, partially offset by $595 million in higher issuances of long-term debt (see below).

Significant Financing Activities. On December 16, 2015, the Pinnacle West Board of Directors declared a quarterly dividend of $0.625 per share of common stock, payable on March 1, 2016, to shareholders of record on February 1, 2015. During 2015, Pinnacle West increased its indicated annual dividend from $2.38 per share to $2.50 per share. For the year ended December 31, 2015, Pinnacle West's total dividends paid per share of common stock were $2.41 per share, which resulted in dividend payments of $260 million.

On January 12, 2015, APS issued $250 million of 2.20% unsecured senior notes that mature on January 15, 2020. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On May 19, 2015, APS issued $300 million of 3.15% unsecured senior notes that mature on May 15, 2025. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper borrowings and drawings under our revolving credit facilities, incurred in connection with the payment at maturity of our $300 million aggregate principal amount of 4.65% notes due May 15, 2015.

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On June 26, 2015, APS entered into a $50 million term loan facility that matures June 26, 2018. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

On November 6, 2015, APS issued $250 million of 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance via redemption and cancellation at par our indebtedness related to the principal amounts of the Navajo County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A and 2009 Series C both due June 1, 2034, and repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla

Project), 2009 Series A. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On November 17, 2015, APS canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series B, purchased in connection with the mandatory tender provision on May 30, 2014.

On December 8, 2015, APS redeemed at par and canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series C.

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, 2015, Pinnacle West had a $200 million revolving credit facility that matures in May 2019. 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, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

On September 2, 2015, APS replaced its $500 million revolving credit facility that would have matured in April 2018, with a new $500 million facility that matures in September 2020.

At December 31, 2015, APS had two credit facilities totaling $1 billion, including the $500 million credit facility that matures in September 2020 and a $500 million credit facility that matures in May 2019. APS may increase the amount of each facility up to a maximum of $700 million each, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2015, APS had no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 10 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 16 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, 2015, the ratio was approximately 47% for Pinnacle West and 46% 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 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 and term loan facilities contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

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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 12, 2016 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	A3	A-	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	A2	A-	A-
Senior unsecured	A2	A-	A
Commercial paper	P-1	A-2	F2
Outlook	Stable	Stable	Stable

Off-Balance Sheet Arrangements

See Note 18 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

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Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2015 (dollars in millions):

	2016	2017-2018	2019-2020	Thereafter	Total
Long-term debt payments, including interest: (a)					
APS	$542	$414	$1,011	$4,422	$6,389
Pinnacle West	2	127	—	—	129
Total long-term debt payments, including interest	544	541	1,011	4,422	6,518
Fuel and purchased power commitments (b)	643	1,174	1,064	7,559	10,440
Renewable energy credits (c)	42	80	80	432	634
Purchase obligations (d)	233	512	37	213	995
Coal reclamation	15	34	39	262	350
Nuclear decommissioning funding requirements	2	4	4	62	72
Noncontrolling interests (e)	23	46	46	226	341
Operating lease payments	9	16	11	61	97
Total contractual commitments	$1,511	$2,407	$2,292	$13,237	$19,447

(a) The long-term debt matures at various dates through 2045 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2015 (see Note 6).

(b) 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 10). These amounts include commitments incurred assuming an additional 7% in the 2016 Coal Supply Agreement.

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

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

(e) Payments to the noncontrolling interests relate to the Palo Verde Sale Leaseback (see Note 18).

This table excludes $34 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. Estimated minimum required pension contributions are zero for 2016, 2017 and 2018 (see Note 7).

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.

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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 $1,364 million of regulatory assets and $1,140 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2015.

Included in the balance of regulatory assets at December 31, 2015 is a regulatory asset of $619 million for pension 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 over the long-term, the mortality assumptions, 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, 2015 reported pension liability on the Consolidated Balance Sheets and our 2015 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%	$(329)	$(11)
Decrease 1%	399	16
Expected long-term rate of return on plan assets:		
Increase 1%	—	(13)
Decrease 1%	—	13

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

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The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2015 other postretirement benefit obligation and our 2015 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):

Actuarial Assumption (a)	Increase (Decrease) Impact on Other Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Discount rate:		
Increase 1%	$(84)	$(3)
Decrease 1%	107	6
Healthcare cost trend rate (b):		
Increase 1%	100	9
Decrease 1%	(80)	(6)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	—	(4)
Decrease 1%	—	4

(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 7 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. We utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The significance of a particular input determines how the instrument is classified in a fair value hierarchy. 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 13 for fair value measurement disclosures.

OTHER ACCOUNTING MATTERS

During the fourth quarter of 2015, we early adopted two new accounting standards related to balance sheet presentation of debt issuance costs, and balance sheet presentation of deferred income taxes. The adoption of these standards did not impact our results of operations or cash flows.

During the first quarter of 2016, we will be adopting new consolidation accounting guidance. We do not expect the adoption of this guidance to have a material impact on our financial statements.

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We are currently evaluating the impacts of adopting new revenue recognition guidance and financial instrument recognition and measurement guidance. These two new accounting standards will be effective for us on January 1, 2018.

See Note 2 for additional information related to accounting matters.

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 13 and Note 19) 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, 2015 and 2014. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2015 and 2014 (dollars in millions):

Pinnacle West – Consolidated

	Variable-Rate Long-Term Debt			Fixed-Rate Long-Term Debt		
2015	Interest Rates		Amount	Interest Rates		Amount
2016	0.01	%	$44	6.15	%	$314
2017	1.17	%	125	—		—
2018	1.02	%	50	1.75	%	32
2019	—		—	8.75	%	500
2020	—		—	2.20	%	250
Years thereafter	0.23	%	49	4.64	%	2,490
Total			$268			$3,586
Fair value			$268			$3,839

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2014	Short-Term Debt Interest Rates		Amount	Variable-Rate Long-Term Debt Interest Rates		Amount	Fixed-Rate Long-Term Debt Interest Rates		Amount
2015	0.40	%	$147	0.03	%	$32	4.32	%	$352
2016	—		—	0.04	%	44	6.15	%	314
2017	—		—	0.82	%	157	—		—
2018	—		—	—		—	1.75	%	32
2019	—		—	—		—	8.75	%	500
Years thereafter	—		—	0.27	%	49	4.90	%	1,940
Total			$147			$282			$3,138
Fair value			$147			$282			$3,558

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, 2015 and 2014. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2015 and 2014 (dollars in millions):

APS — Consolidated

2015	Variable-Rate Long-Term Debt Interest Rates		Amount	Fixed-Rate Long-Term Debt Interest Rates		Amount
2016	0.01	%	$44	6.15	%	$314
2017	—		—	—		—
2018	1.02	%	50	1.75	%	32
2019	—		—	8.75	%	500
2020	—		—	2.20	%	250
Years thereafter	0.23	%	49	4.64	%	2,490
Total			$143			$3,586
Fair value			$143			$3,839

2014	Short-Term Debt Interest Rates		Amount	Variable-Rate Long-Term Debt Interest Rates		Amount	Fixed-Rate Long-Term Debt Interest Rates		Amount
2015	0.40	%	$147	0.03	%	$32	4.32	%	$352
2016	—		—	0.04	%	44	6.15	%	314
2017	—		—	0.03	%	32	—		—
2018	—		—	—		—	1.75	%	32
2019	—		—	—		—	8.75	%	500
Years thereafter	—		—	0.27	%	49	4.90	%	1,940
Total			$147			$157			$3,138
Fair value			$147			$157			$3,558

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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.

The following table shows the net pretax changes in mark-to-market of our derivative positions in 2015 and 2014 (dollars in millions):

	2015	2014
Mark-to-market of net positions at beginning of year	$(115)	$(73)
Increase in regulatory asset	(44)	(64)
Recognized in OCI:		
Change in mark-to-market losses for future deliveries	(1)	—
Mark-to-market losses realized during the period	6	22
Change in valuation techniques	—	—
Mark-to-market of net positions at end of year	$(154)	$(115)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2015 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	2016	2017	2018	2019	2020	Total fair value
Observable prices provided by other external sources	$(65)	$(40)	$(16)	$—	$—	$(121)
Prices based on unobservable inputs	(11)	(7)	(7)	(6)	(2)	(33)
Total by maturity	$(76)	$(47)	$(23)	$(6)	$(2)	$(154)

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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, 2015 and 2014 (dollars in millions):

	December 31, 2015		December 31, 2014	
	Gain (Loss)		Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) or OCI (a)				
Electricity	$2	$ (2)	$3	$ (3)
Natural gas	35	(35)	29	(29)
Total	$37	$ (37)	$32	$ (32)

(a) 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 16 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 risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND
FINANCIAL STATEMENT SCHEDULES

See Note 12 for the selected quarterly financial data (unaudited) required to be presented in this Item.

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 (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control — Integrated Framework (2013), our management concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 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 19, 2016

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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, 2015 and 2014, 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, 2015. 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, 2015, based on criteria established in Internal Control — Integrated Framework (2013) 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 and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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.

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

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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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 19, 2016

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PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(dollars and shares in thousands, except per share amounts)

	Year Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$3,495,443	$3,491,632	$3,454,628
OPERATING EXPENSES			
Fuel and purchased power	1,101,298	1,179,829	1,095,709
Operations and maintenance	868,377	908,025	924,727
Depreciation and amortization	494,422	417,358	415,708
Taxes other than income taxes	171,812	172,295	164,167
Other expenses	4,932	2,883	7,994
Total	2,640,841	2,680,390	2,608,305
OPERATING INCOME	854,602	811,242	846,323
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	35,215	30,790	25,581
Other income (Note 17)	621	9,608	1,704
Other expense (Note 17)	(17,823)	(21,746)	(16,024)
Total	18,013	18,652	11,261
INTEREST EXPENSE			
Interest charges	194,964	200,950	201,888
Allowance for borrowed funds used during construction (Note 1)	(16,259)	(15,457)	(14,861)
Total	178,705	185,493	187,027
INCOME BEFORE INCOME TAXES	693,910	644,401	670,557
INCOME TAXES (Note 4)	237,720	220,705	230,591
NET INCOME	456,190	423,696	439,966
Less: Net income attributable to noncontrolling interests (Note 18)	18,933	26,101	33,892
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$437,257	$397,595	$406,074
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	111,026	110,626	109,984
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	111,552	111,178	110,806
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$3.94	$3.59	$3.69
Net income attributable to common shareholders — diluted	$3.92	$3.58	$3.66

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

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PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
NET INCOME	$456,190	$423,696	$439,966
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $(342), $(438), and $140 (Note 16)	(957)	(810)	(213)
Reclassification of net realized loss, net of tax benefit of $1,801, $7,932 and $17,472 (Note 16)	4,187	13,483	26,747
Pension and other postretirement benefits activity, net of tax (expense) benefit of $(13,302), $1,307, and $(6,156) (Note 7)	20,163	(2,761)	9,421
Total other comprehensive income	23,393	9,912	35,955
COMPREHENSIVE INCOME	479,583	433,608	475,921
Less: Comprehensive income attributable to noncontrolling interests	18,933	26,101	33,892
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$460,650	$407,507	$442,029

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

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PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$39,488	$7,604
Customer and other receivables	274,691	297,740
Accrued unbilled revenues	96,240	100,533
Allowance for doubtful accounts	(3,125)	(3,094)
Materials and supplies (at average cost)	234,234	218,889
Fossil fuel (at average cost)	45,697	37,097
Deferred income taxes (Note 4)	—	122,232
Income tax receivable (Note 4)	589	3,098
Assets from risk management activities (Note 16)	15,905	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	149,555	129,808
Other current assets	37,242	38,817
Total current assets	890,516	973,435
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 16)	12,106	17,620
Nuclear decommissioning trust (Notes 13 and 19)	735,196	713,866
Other assets	52,518	54,047
Total investments and other assets	799,820	785,533
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	16,222,232	15,543,063
Accumulated depreciation and amortization	(5,594,094)	(5,397,751)
Net	10,628,138	10,145,312
Construction work in progress	816,307	682,807
Palo Verde sale leaseback, net of accumulated depreciation of $233,665 and $229,795 (Note 18)	117,385	121,255
Intangible assets, net of accumulated amortization of $546,038 and $489,538	123,975	119,755
Nuclear fuel, net of accumulated amortization of $146,228 and $143,554	123,139	125,201
Total property, plant and equipment	11,808,944	11,194,330
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	1,214,146	1,054,087
Assets for other postretirement benefits (Note 7)	185,997	152,290
Other	128,835	129,215
Total deferred debits	1,528,978	1,335,592
TOTAL ASSETS	$15,028,258	$14,288,890

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

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PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	2014
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$297,480	$295,211
Accrued taxes (Note 4)	138,600	140,613
Accrued interest	56,305	52,603
Common dividends payable	69,363	65,790
Short-term borrowings (Note 5)	—	147,400
Current maturities of long-term debt (Note 6)	357,580	383,570
Customer deposits	73,073	72,307
Liabilities from risk management activities (Note 16)	77,716	59,676
Liabilities for asset retirements (Note 11)	28,573	32,462
Deferred fuel and purchased power regulatory liability (Note 3)	9,688	—
Other regulatory liabilities (Note 3)	136,078	130,549
Other current liabilities	197,861	178,962
Total current liabilities	1,442,317	1,559,143
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	3,462,391	3,006,573
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,723,425	2,582,636
Regulatory liabilities (Notes 1, 3, 4 and 7)	994,152	1,051,196
Liabilities for asset retirements (Note 11)	415,003	358,288
Liabilities for pension benefits (Note 7)	480,998	453,736
Liabilities from risk management activities (Note 16)	89,973	50,602
Customer advances	115,609	123,052
Coal mine reclamation	201,984	198,292
Deferred investment tax credit	187,080	178,607
Unrecognized tax benefits (Note 4)	9,524	19,377
Other	186,345	188,286
Total deferred credits and other	5,404,093	5,204,072
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 111,095,402 and 110,649,762 issued at respective dates	2,541,668	2,512,970
Treasury stock at cost; 115,030 shares at end of 2015 and 78,400 shares at end of 2014	(5,806)	(3,401)
Total common stock	2,535,862	2,509,569
Retained earnings	2,092,803	1,926,065
Accumulated other comprehensive loss:		
Pension and other postretirement benefits (Note 7)	(37,593)	(57,756)
Derivative instruments (Note 16)	(7,155)	(10,385)
Total accumulated other comprehensive loss	(44,748)	(68,141)
Total shareholders’ equity	4,583,917	4,367,493
Noncontrolling interests (Note 18)	135,540	151,609

Total equity	4,719,457	4,519,102
TOTAL LIABILITIES AND EQUITY	$15,028,258	$14,288,890

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

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PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$456,190	$423,696	$439,966
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	571,664	496,487	492,322
Deferred fuel and purchased power	14,997	(26,927)	21,678
Deferred fuel and purchased power amortization	1,617	40,757	31,190
Allowance for equity funds used during construction	(35,215)	(30,790)	(25,581)
Deferred income taxes	236,819	159,023	249,296
Deferred investment tax credit	8,473	26,246	52,542
Change in derivative instruments fair value	(381)	339	534
Changes in current assets and liabilities:			
Customer and other receivables	(22,219)	(52,672)	(44,991)
Accrued unbilled revenues	4,293	(3,737)	(1,951)
Materials, supplies and fossil fuel	(23,945)	3,724	(11,878)
Income tax receivable	2,509	132,419	(133,094)
Other current assets	3,145	4,384	(17,913)
Accounts payable	(34,266)	(353)	45,414
Accrued taxes	(2,013)	9,615	6,059
Other current liabilities	603	17,892	(7,513)
Change in margin and collateral accounts — assets	(324)	(343)	993
Change in margin and collateral accounts — liabilities	22,776	(24,975)	12,355
Change in long-term income tax receivable	—	—	137,270
Change in unrecognized tax benefits	(10,328)	2,778	(91,425)
Change in long-term regulatory liabilities	(20,535)	59,618	64,473
Change in other long-term assets	2,426	(56,561)	(42,389)
Change in other long-term liabilities	(81,959)	(80,993)	(24,050)
Net cash flow provided by operating activities	1,094,327	1,099,627	1,153,307
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,076,087)	(910,634)	(1,016,322)
Contributions in aid of construction	46,546	20,325	41,090
Allowance for borrowed funds used during construction	(16,259)	(15,457)	(14,861)
Proceeds from nuclear decommissioning trust sales	478,813	356,195	446,025
Investment in nuclear decommissioning trust	(496,062)	(373,444)	(463,274)
Other	(3,184)	347	(2,059)
Net cash flow used for investing activities	(1,066,233)	(922,668)	(1,009,401)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	842,415	731,126	136,307
Repayment of long-term debt	(415,570)	(652,578)	(122,828)
Short-term borrowings and payments — net	(147,400)	(5,725)	60,950
Dividends paid on common stock	(260,027)	(246,671)	(235,244)
Common stock equity issuance - net of purchases	19,373	15,288	17,319

Distributions to noncontrolling interests	(35,002)	(20,482)	(17,385)
Other	1	161	299
Net cash flow provided by (used for) financing activities	3,790	(178,881)	(160,582)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	31,884	(1,922)	(16,676)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	7,604	9,526	26,202
CASH AND CASH EQUIVALENTS AT END OF YEAR	$39,488	$7,604	$9,526

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

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PINNACLE WEST CAPITAL CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands, except per share amounts)

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, December 31, 2012	109,837,957	$2,466,923	(95,192)	$(4,211)	$1,624,102	$(114,008)	$129,483	$4,102,289
Net income		—		—	406,074	—	33,892	439,966
Other comprehensive income		—		—	—	35,955	—	35,955
Dividends on common stock ($2.23 per share)		—		—	(244,903)	—	—	(244,903)
Issuance of common stock	442,746	24,635		—	—	—	—	24,635
Purchase of treasury stock (a)		—	(174,290)	(9,727)	—	—	—	(9,727)
Reissuance of treasury stock for stock-based compensation and other		—	170,538	9,630	—	—	—	9,630
Net capital activities by noncontrolling interests		—		—	—	—	(17,385)	(17,385)
Balance, December 31, 2013	110,280,703	2,491,558	(98,944)	(4,308)	1,785,273	(78,053)	145,990	4,340,460
Net income		—		—	397,595	—	26,101	423,696
Other comprehensive income		—		—	—	9,912	—	9,912
Dividends on common stock ($2.33 per share)		—		—	(256,803)	—	—	(256,803)
Issuance of common stock	369,059	21,412		—	—	—	—	21,412
Purchase of treasury stock (a)		—	(139,746)	(7,893)	—	—	—	(7,893)

Reissuance of treasury stock for stock-based compensation and other		—	160,290	8,800	—	—	—	8,800
Net capital activities by noncontrolling interests		—		—	—	—	(20,482)	(20,482)
Balance, December 31, 2014	110,649,762	2,512,970	(78,400)	(3,401)	1,926,065	(68,141)	151,609	4,519,102
Net income		—		—	437,257	—	18,933	456,190
Other comprehensive income		—		—	—	23,393	—	23,393
Dividends on common stock ($2.44 per share)		—		—	(270,519)	—	—	(270,519)
Issuance of common stock	445,640	28,698		—	—	—	—	28,698
Purchase of treasury stock (a)		—	(154,751)	(10,136)	—	—	—	(10,136)
Reissuance of treasury stock for stock-based compensation and other		—	118,121	7,731	—	—	—	7,731
Net capital activities by noncontrolling interests		—		—	—	—	(35,002)	(35,002)
Balance, December 31, 2015	111,095,402	$2,541,668	(115,030)	$(5,806)	$2,092,803	$(44,748)	$135,540	$4,719,457

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.

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

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MANAGEMENT'S REPORT ON INTERNAL CONTROL
OVER FINANCIAL REPORTING
(ARIZONA PUBLIC SERVICE COMPANY)

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 APS. Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control — Integrated Framework (2013), our management concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 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 financial statements.

February 19, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Arizona Public Service Company
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiary (the "Company") as of December 31, 2015 and 2014, 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, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule 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 and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed 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.

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 Arizona Public Service Company and subsidiary as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents 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, 2015, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 19, 2016

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ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
ELECTRIC OPERATING REVENUES	$3,492,357	$3,488,946	$3,451,251
OPERATING EXPENSES			
Fuel and purchased power	1,101,298	1,179,829	1,095,709
Operations and maintenance	853,135	882,442	897,824
Depreciation and amortization	494,298	417,264	415,612
Income taxes (Note 4)	260,143	245,036	256,864
Taxes other than income taxes	171,499	171,583	163,377
Total	2,880,373	2,896,154	2,829,386
OPERATING INCOME	611,984	592,792	621,865
OTHER INCOME (DEDUCTIONS)			
Income taxes (Note 4)	14,302	7,676	11,769
Allowance for equity funds used during construction (Note 1)	35,215	30,790	25,581
Other income (Note 17)	2,834	11,295	3,896
Other expense (Note 17)	(19,019)	(13,403)	(20,449)
Total	33,332	36,358	20,797
INTEREST EXPENSE			
Interest on long-term debt	180,123	186,323	188,011
Interest on short-term borrowings	7,376	6,796	6,605
Debt discount, premium and expense	4,793	4,168	4,046
Allowance for borrowed funds used during construction (Note 1)	(16,183)	(15,457)	(14,861)
Total	176,109	181,830	183,801
NET INCOME	469,207	447,320	458,861
Less: Net income attributable to noncontrolling interests (Note 18)	18,933	26,101	33,892
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$450,274	$421,219	$424,969

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

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ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
NET INCOME	$469,207	$447,320	$458,861
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of $(342), $(438), and $140 (Note 16)	(957)	(809)	(214)
Reclassification of net realized loss, net of tax benefit of $1,801, $7,932, and $17,472 (Note 16)	4,187	13,483	26,747
Pension and other postretirement benefits activity, net of tax (expense) benefit of $(11,776), $4,655, and $(6,003) (Note 7)	18,006	(7,635)	9,190
Total other comprehensive income	21,236	5,039	35,723
COMPREHENSIVE INCOME	490,443	452,359	494,584
Less: Comprehensive income attributable to noncontrolling interests	18,933	26,101	33,892
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$471,510	$426,258	$460,692

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

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ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	2014
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	$16,218,724	$15,539,811
Accumulated depreciation and amortization	(5,590,937)	(5,394,650)
Net	10,627,787	10,145,161
Construction work in progress	812,845	682,807
Palo Verde sale leaseback, net of accumulated depreciation of $233,665 and $229,795 (Note 18)	117,385	121,255
Intangible assets, net of accumulated amortization of $546,038 and $489,538	123,820	119,600
Nuclear fuel, net of accumulated amortization of $146,228 and $143,554	123,139	125,201
Total property, plant and equipment	11,804,976	11,194,024
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 13 and 19)	735,196	713,866
Assets from risk management activities (Note 16)	12,106	17,620
Other assets	34,455	33,362
Total investments and other assets	781,757	764,848
CURRENT ASSETS		
Cash and cash equivalents	22,056	4,515
Customer and other receivables	274,428	297,712
Accrued unbilled revenues	96,240	100,533
Allowance for doubtful accounts	(3,125)	(3,094)
Materials and supplies (at average cost)	234,234	218,889
Fossil fuel (at average cost)	45,697	37,097
Assets from risk management activities (Note 16)	15,905	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	149,555	129,808
Deferred income taxes (Note 4)	—	55,253
Other current assets	35,765	38,693
Total current assets	870,755	900,117
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, and 4)	1,214,146	1,054,087
Assets for other postretirement benefits (Note 7)	182,625	149,260
Other	127,923	128,026
Total deferred debits	1,524,694	1,331,373
TOTAL ASSETS	$14,982,182	$14,190,362

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

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ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	December 31, 2015	2014
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$178,162	$178,162
Additional paid-in capital	2,379,696	2,379,696
Retained earnings	2,148,493	1,968,718
Accumulated other comprehensive (loss):		
Pension and other postretirement benefits (Note 7)	(19,942)	(37,948)
Derivative instruments (Note 16)	(7,155)	(10,385)
Total shareholder equity	4,679,254	4,478,243
Noncontrolling interests (Note 18)	135,540	151,609
Total equity	4,814,794	4,629,852
Long-term debt less current maturities (Note 6)	3,337,391	2,881,573
Total capitalization	8,152,185	7,511,425
CURRENT LIABILITIES		
Short-term borrowings (Note 5)	—	147,400
Current maturities of long-term debt (Note 6)	357,580	383,570
Accounts payable	291,574	289,930
Accrued taxes (Note 4)	144,488	131,110
Accrued interest	56,003	52,358
Common dividends payable	69,400	65,800
Customer deposits	73,073	72,307
Liabilities from risk management activities (Note 16)	77,716	59,676
Liabilities for asset retirements (Note 11)	28,573	32,462
Deferred fuel and purchased power regulatory liability (Note 3)	9,688	—
Other regulatory liabilities (Note 3)	136,078	130,549
Other current liabilities	180,535	167,302
Total current liabilities	1,424,708	1,532,464
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	2,764,489	2,571,365
Regulatory liabilities (Notes 1, 3, and 4)	994,152	1,051,196
Liabilities for asset retirements (Note 11)	415,003	358,288
Liabilities for pension benefits (Note 7)	459,065	424,508
Liabilities from risk management activities (Note 16)	89,973	50,602
Customer advances	115,609	123,052
Coal mine reclamation	201,984	198,292
Deferred investment tax credit	187,080	178,607
Unrecognized tax benefits (Note 4)	35,251	45,740
Other	142,683	144,823
Total deferred credits and other	5,405,289	5,146,473
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$14,982,182	$14,190,362

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

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ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)

	Year Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$469,207	$447,320	$458,861
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	571,540	496,393	492,226
Deferred fuel and purchased power	14,997	(26,927)	21,678
Deferred fuel and purchased power amortization	1,617	40,757	31,190
Allowance for equity funds used during construction	(35,215)	(30,790)	(25,581)
Deferred income taxes	223,069	155,401	278,101
Deferred investment tax credit	8,473	26,246	52,542
Change in derivative instruments fair value	(381)	339	534
Changes in current assets and liabilities:			
Customer and other receivables	(21,040)	(52,466)	(46,552)
Accrued unbilled revenues	4,293	(3,737)	(1,951)
Materials, supplies and fossil fuel	(23,945)	3,724	(11,878)
Income tax receivable	—	135,179	(134,590)
Other current assets	4,498	3,766	(17,112)
Accounts payable	(34,891)	(2,355)	47,870
Accrued taxes	13,378	8,650	5,760
Other current liabilities	(3,718)	33,970	(9,005)
Change in margin and collateral accounts — assets	(324)	(343)	993
Change in margin and collateral accounts — liabilities	22,776	(24,975)	12,355
Change in long-term regulatory liabilities	(20,535)	59,618	64,473
Change in long-term income tax receivable	—	—	137,665
Change in unrecognized tax benefits	(10,328)	2,778	(91,244)
Change in other long-term assets	(813)	(62,739)	(46,675)
Change in other long-term liabilities	(82,628)	(85,642)	(24,969)
Net cash flow provided by operating activities	1,100,030	1,124,167	1,194,691
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,072,053)	(910,084)	(1,016,322)
Contributions in aid of construction	46,546	20,325	41,090
Allowance for borrowed funds used during construction	(16,183)	(15,457)	(14,861)
Proceeds from nuclear decommissioning trust sales	478,813	356,195	446,025
Investment in nuclear decommissioning trust	(496,062)	(373,444)	(463,274)
Other	(1,093)	347	(2,067)
Net cash flow used for investing activities	(1,060,032)	(922,118)	(1,009,409)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	842,415	606,126	136,307
Repayment of long-term debt	(415,570)	(527,578)	(122,828)
Short-term borrowings and payments — net	(147,400)	(5,725)	60,950
Dividends paid on common stock	(266,900)	(253,600)	(242,100)
Noncontrolling interests	(35,002)	(20,482)	(17,385)
Net cash flow used for financing activities	(22,457)	(201,259)	(185,056)

NET INCREASE IN CASH AND CASH EQUIVALENTS	17,541	790	226
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	4,515	3,725	3,499
CASH AND CASH EQUIVALENTS AT END OF YEAR	$22,056	$4,515	$3,725
Supplemental disclosure of cash flow information:			
Cash paid (received) during the year for:			
Income taxes, net of refunds	$14,831	$(86,054)	$7,524
Interest, net of amounts capitalized	167,670	173,436	180,757
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$83,798	$44,712	$33,184
Dividends declared but not paid	69,400	65,800	62,500
Liabilities assumed related to acquisition of SCE's Four Corners' interest	—	—	145,609

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

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ARIZONA PUBLIC SERVICE COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(dollars in thousands)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, December 31, 2012	71,264,947	$178,162	$2,379,696	$1,624,237	$(89,095)	$129,483	$4,222,483
Net income		—	—	424,969	—	33,892	458,861
Other comprehensive income		—	—	—	35,723	—	35,723
Dividends on common stock		—	—	(244,800)	—	—	(244,800)
Other		—	—	(8)	—	—	(8)
Net capital activities by noncontrolling interests		—	—	—	—	(17,385)	(17,385)
Balance, December 31, 2013	71,264,947	178,162	2,379,696	1,804,398	(53,372)	145,990	4,454,874
Net income		—	—	421,219	—	26,101	447,320
Other comprehensive income		—	—	—	5,039	—	5,039
Dividends on common stock		—	—	(256,900)	—	—	(256,900)
Other		—	—	1	—	—	1
Net capital activities by noncontrolling interests		—	—	—	—	(20,482)	(20,482)
Balance, December 31, 2014	71,264,947	178,162	2,379,696	1,968,718	(48,333)	151,609	4,629,852
Net income		—	—	450,274	—	18,933	469,207
Other comprehensive income		—	—	—	21,236	—	21,236
Dividends on common stock		—	—	(270,500)	—	—	(270,500)
Other		—	—	1	—	—	1
Net capital activities by noncontrolling interests		—	—	—	—	(35,002)	(35,002)
Balance, December 31, 2015	71,264,947	$178,162	$2,379,696	$2,148,493	$(27,097)	$135,540	$4,814,794

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

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COMBINED 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, El Dorado, and BCE. 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. El Dorado is an investment firm. BCE is a subsidiary that was formed in 2014 that focuses on growth opportunities that leverage the Company's core expertise in the electric energy industry. BCE is currently pursuing transmission opportunities through a joint venture arrangement.

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, El Dorado and BCE. 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 18).

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.

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.

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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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.

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.

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Pinnacle West’s property, plant and equipment included in the December 31, 2015 and 2014 consolidated balance sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	2015	2014
Generation	$7,336,902	$7,158,729
Transmission	2,494,744	2,247,309
Distribution	5,543,561	5,339,322
General plant	847,025	797,703
Plant in service and held for future use	16,222,232	15,543,063
Accumulated depreciation and amortization	(5,594,094)	(5,397,751)
Net	10,628,138	10,145,312
Construction work in progress	816,307	682,807
Palo Verde sale leaseback, net of accumulated depreciation	117,385	121,255
Intangible assets, net of accumulated amortization	123,975	119,755
Nuclear fuel, net of accumulated amortization	123,139	125,201
Total property, plant and equipment	$11,808,944	$11,194,330

Property, plant and equipment balances and classes for APS are not materially different than Pinnacle West.

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 11.

APS records a regulatory liability 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, 2015 were as follows:

- Fossil plant — 19 years;
- Nuclear plant — 28 years;
- Other generation — 25 years;
- Transmission — 39 years;
- Distribution — 33 years; and
- Other — 7 years.

Pursuant to an ACC order, we deferred operating costs in 2013 and 2014 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 were deferred and are now being amortized on the depreciation line of the Consolidated Statements of Income.

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Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $430 million in 2015, $396 million in 2014, and $400 million in 2013. For the years 2013 through 2015, the depreciation rates ranged from a low of 0.30% to a high of 12.37%. The weighted-average depreciation rate was 2.74% in 2015, 2.77% in 2014, and 3.00% in 2013.

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 Statements 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 8.02% for 2015, 8.47% for 2014, and 8.56% for 2013. 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.

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.

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See Note 13 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 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 16 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 Postretirement 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 its 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 7 for additional information on pension and other postretirement benefits.

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 charged APS $0.001 per kWh of nuclear generation through May 2014, at which point the DOE suspended the fee. In accordance with a settlement agreement with the DOE in August 2014, we will now accrue a receivable for incurred claims and

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an offsetting regulatory liability through the settlement period ending December of 2016. See Note 10 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):

	Year ended December 31,		
	2015	2014	2013
Cash paid (received) during the period for:			
Income taxes, net of refunds	$6,550	$(102,154)	$18,537
Interest, net of amounts capitalized	170,209	177,074	184,010
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$83,798	$44,712	$33,184
Dividends declared but not paid	69,363	65,790	62,528
Liabilities assumed relating to acquisition of SCE Four Corners' interest (see Note 3)	—	—	145,609

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 $58 million in 2015, $53 million in 2014, and $53 million in 2013. Estimated amortization expense on existing intangible assets over the next five years is $48 million in 2016, $36 million in 2017, $18 million in 2018, $9 million in 2019, and $3 million in 2020. At December 31, 2015, the weighted-average remaining amortization period for intangible assets was 5 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 and no significant influence).

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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 13 and Note 19 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.

Preferred Stock

At December 31, 2015, Pinnacle West had 10 million shares of serial preferred stock authorized with no par value, none of which was outstanding, and APS had 15,535,000 shares of various types of preferred stock authorized with $25, $50 and $100 par values, none of which was outstanding.

2. New Accounting Standards

In May 2014, new revenue recognition guidance was issued. This guidance provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. The new revenue standard will be effective for us on January 1, 2018. The guidance may be adopted using a full retrospective application or a simplified transition method that allows entities to record a cumulative effect adjustment in retained earnings at the date of initial application. We are currently evaluating this new guidance and the impacts it may have on our financial statements.

In February 2015, new consolidation accounting guidance was issued that amends many aspects of the guidance relating to the analysis and consolidation of variable interest entities. The new guidance is effective for us, and will be adopted, during the first quarter of 2016; and may be adopted using either a full retrospective or modified retrospective approach. We do not expect the adoption of this guidance to have a material impact on our financial statements.

In January 2016, new guidance was issued relating to the recognition and measurement of financial instruments. The amended guidance will require certain investments in equity securities to be measured at fair value with changes in fair value recognized in net income, and modifies the impairment assessment of certain equity securities. The new guidance is effective for us on January 1, 2018. Certain aspects of the guidance may require a cumulative-effect adjustment and other aspects of the guidance are required to be adopted prospectively. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.
During the fourth quarter of 2015 we elected to early adopt the following accounting standard updates:

- Balance sheet presentation of deferred income taxes. See Note 4.

- Balance sheet presentation of debt issuance costs: Adopted on a retrospective basis, the new guidance requires debt issuance costs to be presented on the balance sheets as a direct reduction to the related debt liabilities. Prior to the adoption of this guidance we were required to present debt issuance costs as an asset on the balance sheets. As a result of adopting this guidance, our December 31, 2015 Consolidated Balance Sheet includes $28 million of debt issuance costs as a reduction to our long-term debt. Our December 31, 2014 Consolidated Balance Sheet presents $25 million of debt issuance costs as a reduction to long-term debt; this amount was previously presented as a component of non-current other deferred debits. The adoption of this guidance did not impact our results of operations or cash flows. Debt issuance costs continue to be amortized as interest expense. See Note 6.

3. Regulatory Matters

Retail Rate Case Filings with the Arizona Corporation Commission

Upcoming Rate Case Filing

On January 29, 2016, APS filed a NOI informing the ACC that APS intends to submit a rate case application in June 2016 using an adjusted test year ending December 31, 2015. The NOI provides an overview of the key issues APS expects to address in its formal request such as rate design changes (residential, commercial and industrial), a decoupling mechanism, permission to defer for potential future recovery costs associated with the Company's Ocotillo Modernization Project, permission to defer for potential future recovery costs associated with environmental standards compliance, inclusion of post-test year plant and modifications to certain adjustor mechanisms, among other items. In its rate application, APS will request that its proposed pricing changes take effect in July 2017. APS is still developing the exact amount of the request.

Prior Rate Case Filing

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.

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:

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- Deferral of increases in property taxes 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;
- 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, see "Four Corners" below);
- 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;
- 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.

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.

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 to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

In accordance with the ACC's decision on the 2014 RES plan, on April 15, 2014, APS filed an application with the ACC requesting permission to build an additional 20 MW of APS-owned utility scale solar under the AZ Sun Program. In a subsequent filing, APS also offered an alternative proposal to replace the 20 MW of utility scale solar with 10 MW (approximately 1,500 customers) of APS-owned residential solar that will not be under the AZ Sun Program. On December 19, 2014, the ACC voted that it had no objection to APS implementing its residential rooftop solar program. The first stage of the residential rooftop solar program, called the "Solar Partner Program", is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes shall not be made until the project is fully in service and APS requests cost recovery in a future rate case.

On July 1, 2014, APS filed its 2015 RES implementation plan and proposed a RES budget of approximately $154 million. On December 31, 2014, the ACC issued a decision approving the 2015 RES implementation plan with minor modifications, including reducing the requested budget to approximately $152 million.

On July 1, 2015, APS filed its 2016 RES implementation plan and proposed a RES budget of approximately $148 million. On January 12, 2016, the ACC approved APS's plan and requested budget.

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

On June 1, 2012, APS filed its 2013 DSM Plan. In 2013, the standards required 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.

On March 11, 2014, the ACC issued an order approving APS's 2013 DSM Plan. The ACC approved a budget of $68.9 million for each of 2013 and 2014. The ACC also approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. The ACC approved APS's 2015 DSM budget on November 25, 2015. In its decision, the ACC also approved that verified energy savings from APS's resource savings projects could be counted toward compliance with the Electric Energy Efficiency Standard, however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of its achievement tier level for its performance incentive, nor may APS include savings from conservation voltage reduction in the calculation of its LFCR mechanism.

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On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. The DSM Plan also proposed a reduction in the DSMAC of approximately 12%.

Electric Energy Efficiency. On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 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.

On November 4, 2014, the ACC staff issued a request for informal comment on a draft of possible amendments to Arizona's Electric Energy Efficiency Standards. The draft proposed substantial changes to the rules and energy efficiency standards. The ACC accepted written comments and took public comment regarding the possible amendments on December 19, 2014. A formal rulemaking has not been initiated and there has been no additional action on the draft to date.

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 1 (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);
- 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.

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The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Beginning balance	$6,926	$20,755
Deferred fuel and purchased power costs - current period	(14,997)	26,927
Amounts charged to customers	(1,617)	(40,756)
Ending balance	$(9,688)	$6,926

The PSA rate for the PSA year beginning February 1, 2016 is $0.001678 per kWh, as compared to $0.000887 per kWh for the prior year. This new rate is comprised of a forward component of $0.001975 per kWh and a historical component of $(0.000297) per kWh. On October 15, 2015, APS notified the ACC that it was initiating a PSA transition component of $(0.004936) per kWh for the months of November 2015, December 2015, and January 2016. The PSA transition component is a mid-year adjustment to the PSA rate that may be established when conditions change sufficiently to cause high balances to accrue in the PSA balancing account. The transition component expired on February 1, 2016. Any uncollected (overcollected) deferrals during the PSA year, after accounting for the transition component, will be included in the calculation of the PSA rate for the PSA year beginning February 1, 2017.

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, 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 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 Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts.

Effective June 1, 2014, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $5.9 million for the twelve-month period beginning June 1, 2014 in accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2014.

Effective June 1, 2015, APS's annual wholesale transmission rates for all users of its transmission system decreased by approximately $17.6 million for the twelve-month period beginning June 1, 2015 in accordance with the

FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2015.

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APS's formula rate protocols have been in effect since 2008. Recent FERC orders suggest that FERC is examining the structure of formula rate protocols and may require companies such as APS to make changes to their protocols in the future.

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 LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. 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.

APS files for a LFCR adjustment every January. APS filed its 2014 annual LFCR adjustment on January 15, 2014, requesting a LFCR adjustment of $25.3 million, effective March 1, 2014. The ACC approved APS's LFCR adjustment without change on March 11, 2014, which became effective April 1, 2014. APS filed its 2015 annual LFCR adjustment on January 15, 2015, requesting an LFCR adjustment of $38.5 million, which was approved on March 2, 2015, effective for the first billing cycle of March. APS filed its 2016 annual LFCR adjustment on January 15, 2016, requesting an LFCR adjustment of $46.4 million (a $7.9 million annual increase), to be effective for the first billing cycle of March 2016.

Net Metering

On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. 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 electric grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

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 electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

On October 20, 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing has been scheduled to commence in April 2016. APS cannot predict the outcome of this proceeding.

In 2015, Arizona jurisdictional utilities UNS Electric, Inc. and Tucson Electric Power Company both filed applications with the ACC requesting rate increases. These applications include rate design changes to mitigate the cost shift caused by net metering. On December 9, 2015, APS filed testimony in the UNS Electric, Inc. rate case in support of the UNS Electric, Inc. proposed rate design changes. APS has also requested intervention in the upcoming

Tucson Electric Power Company rate case. The outcomes of these proceedings will not directly impact our financial position.

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Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB")

In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the “fair value” of a utility’s property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC’s method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision and APS filed a brief supporting the ACC’s petition to the Arizona Supreme Court for review of the Court of Appeals’ decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and oral argument is set for March 22, 2016. If the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may require modification. This could in turn have an impact on APS’s ability to recover certain costs in between rate cases. APS cannot predict the outcome of this matter.

Four Corners

On December 30, 2013, APS purchased SCE’s 48% ownership interest in each of Units 4 and 5 of Four Corners. 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 the 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. On December 23, 2014, the ACC approved rate adjustments resulting in a revenue increase of $57.1 million on an annual basis. This includes the deferral for future recovery of all non-fuel operating costs for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Units 1-3 from the date of closing of the purchase through its inclusion in rates. The 2012 Settlement Agreement also provides for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Units 1-3. The deferral balance related to the acquisition of SCE’s interest in Units 4 and 5 and the closure of Units 1-3 was $70 million as of December 31, 2015 and is being amortized in rates over a total of 10 years. On February 23, 2015, the Arizona School Boards Association and the Association of Business Officials filed a notice of appeal in Division 1 of the Arizona Court of Appeals of the ACC decision approving the rate adjustments. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals has suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed above, which could have an effect on the outcome of this Four Corners proceeding. We cannot predict when or how this matter will be resolved.

As part of APS’s acquisition of SCE’s interest in Units 4 and 5, 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 would 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. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

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Cholla

On September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates and plans to seek recovery of the unit's decommissioning and other retirement-related costs over the remaining life of the plant in its next retail rate case. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($122 million as of December 31, 2015), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

Regulatory Assets and Liabilities

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

	Amortization Through	December 31, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Pension	(a)	$—	$619,223	$—	$485,037
Retired power plant costs	2033	9,913	127,518	9,913	136,182
Income taxes - AFUDC equity	2045	5,495	133,712	4,813	118,396
Deferred fuel and purchased power — mark-to-market (Note 16)	2018	71,852	69,697	51,209	46,233
Four Corners cost deferral	2024	6,689	63,582	6,689	70,565
Income taxes — investment tax credit basis adjustment	2045	1,766	48,462	1,716	46,200
Lost fixed cost recovery	2016	45,507	—	37,612	—
Palo Verde VIEs (Note 18)	2046	—	18,143	—	34,440
Deferred compensation	2036	—	34,751	—	34,162
Deferred property taxes	(d)	—	50,453	—	30,283
Loss on reacquired debt	2034	1,515	16,375	1,435	16,410
Tax expense of Medicare subsidy	2024	1,520	12,163	1,528	13,756
Transmission vegetation management	2016	4,543	—	9,086	4,543
Mead-Phoenix transmission line CIAC	2050	332	11,040	332	11,372
Deferred fuel and purchased power (b) (c)	2015	—	—	6,926	—
Coal reclamation	2026	418	6,085	418	6,503
Pension and other postretirement benefits deferral	2015	—	—	4,238	—
Other	Various	5	2,942	819	5
Total regulatory assets (e)		$149,555	$1,214,146	$136,734	$1,054,087

(a)

This asset represents the future recovery of pension 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 7 for further discussion.

(b) See "Cost Recovery Mechanisms" discussion above.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(c) Subject to a carrying charge.
(d) Per the provision of the 2012 Settlement Agreement.
(e) 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, Transmission Cost Adjustor and Other Transmission Matters."

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

	Amortization Through	December 31, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Asset retirement obligations	2057	$—	$277,554	$—	$295,546
Removal costs	(a)	39,746	240,367	31,033	272,825
Other postretirement benefits	(d)	34,100	179,521	32,317	198,599
Income taxes — deferred investment tax credit	2045	3,604	97,175	3,505	92,727
Income taxes - change in rates	2045	1,113	72,454	371	72,423
Spent nuclear fuel	2047	3,051	67,437	4,396	65,594
Renewable energy standard (b)	2017	43,773	4,365	24,596	22,677
Demand side management (b)	2017	6,079	19,115	31,335	—
Sundance maintenance	2030	—	13,678	—	12,069
Deferred fuel and purchased power (b) (c)	2016	9,688	—	—	—
Deferred gains on utility property	2019	2,062	6,001	2,062	8,001
Four Corners coal reclamation	2031	—	8,920	—	1,200
Other	Various	2,550	7,565	934	9,535
Total regulatory liabilities		$145,766	$994,152	$130,549	$1,051,196

(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 11).
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) See Note 7.

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, investment tax credit basis adjustment and tax expense of Medicare subsidy. 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Net income associated with the Palo Verde sale leaseback VIEs is not subject to tax (see Note 18). As a result, there is no income tax expense associated with the VIEs recorded on the Pinnacle West Consolidated and APS 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):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Total unrecognized tax benefits, January 1	$44,775	$41,997	$133,422	$44,775	$41,997	$133,241
Additions for tax positions of the current year	2,175	4,309	3,516	2,175	4,309	3,516
Additions for tax positions of prior years	—	751	13,158	—	751	13,158
Reductions for tax positions of prior years for:						
Changes in judgment	(10,244)	(2,282)	(108,099)	(10,244)	(2,282)	(107,918)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(2,259)	—	—	(2,259)	—	—
Total unrecognized tax benefits, December 31	$34,447	$44,775	$41,997	$34,447	$44,775	$41,997

During the year ended December 31, 2013, Internal Revenue Service ("IRS") guidance was released which provided clarification regarding an APS tax accounting method change approved by the IRS in the third quarter of 2009. As a result of this guidance, uncertain tax positions decreased $67 million. Additionally, the IRS finalized the examination of tax returns for the years ended December 31, 2008 and 2009, which further reduced uncertain tax positions by approximately $41 million. These reductions in uncertain tax positions, materially offset by an increase in deferred tax liabilities, resulted in a cash refund that was received in the first quarter of 2014.

Included in the balances of unrecognized tax benefits are the following tax positions that, if recognized, would decrease our effective tax rate (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Tax positions, that if recognized, would decrease our effective tax rate	$9,523	$11,207	$9,827	$9,523	$11,207	$9,827

As of the balance sheet date, the tax year ended December 31, 2012 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 2011.

We reflect interest and penalties, if any, on unrecognized tax benefits in the Pinnacle West Consolidated and APS Consolidated Statements of Income as income tax expense. The amount of interest expense or benefit recognized related to unrecognized tax benefits are as follows (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Unrecognized tax benefit interest expense/(benefit) recognized	$(161)	$752	$(3,716)	$(161)	$752	$(3,716)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Following are the total amount of accrued liabilities for interest recognized related to unrecognized benefits that could reverse and decrease our effective tax rate to the extent matters are settled favorably (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	2015	2014	2013	2015	2014	2013
Unrecognized tax benefit interest accrued	$804	$965	$213	$804	$965	$213

Additionally, as of December 31, 2015, we have recognized less than $1 million of interest expense to be paid on the underpayment 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):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2015	2014	2013	2015	2014	2013
Current:						
Federal	$(12,335)	$25,054	$(81,784)	$6,485	$40,115	$(97,531)
State	4,763	10,382	10,537	7,813	15,598	11,983
Total current	(7,572)	35,436	(71,247)	14,298	55,713	(85,548)
Deferred:						
Federal	221,505	167,365	279,973	208,326	165,027	305,389
State	23,787	17,904	21,865	23,217	16,620	25,254
Total deferred	245,292	185,269	301,838	231,543	181,647	330,643
Income tax expense	$237,720	$220,705	$230,591	$245,841	$237,360	$245,095

On the APS Consolidated Statements of Income, federal and state income taxes are allocated between operating income and other income.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Pinnacle West Consolidated Year Ended December 31,			APS Consolidated Year Ended December 31,		
	2015	2014	2013	2015	2014	2013
Federal income tax expense at 35% statutory rate	$242,869	$225,540	$234,695	$250,267	$239,638	$246,384
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	18,265	18,149	21,387	20,433	21,148	23,970
Credits and favorable adjustments related to prior years resolved in current year	(2,169)	—	(3,356)	(1,892)	—	(3,231)
Medicare Subsidy Part-D	837	830	823	837	830	823
Allowance for equity funds used during construction (see Note 1)	(9,711)	(8,523)	(6,997)	(9,711)	(8,523)	(6,997)
Palo Verde VIE noncontrolling interest (see Note 18)	(6,626)	(9,135)	(11,862)	(6,626)	(9,135)	(11,862)
Investment tax credit amortization	(5,527)	(4,928)	(3,548)	(5,527)	(4,928)	(3,548)
Other	(218)	(1,228)	(551)	(1,940)	(1,670)	(444)
Income tax expense	$237,720	$220,705	$230,591	$245,841	$237,360	$245,095

During the fourth quarter of 2015, we prospectively adopted guidance requiring deferred income tax assets and liabilities to be presented as non-current on the balance sheet and eliminating the requirement to present a current portion. As a result of this guidance all deferred income tax assets and liabilities are presented as net non-current deferred income tax liabilities on the Consolidated Balance Sheet as of December 31, 2015. Prior periods have not been restated.

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

	Pinnacle West Consolidated December 31,		APS Consolidated December 31,	
	2015	2014	2015	2014
Current asset	$—	$122,232	$—	$55,253
Long-term liability	(2,723,425)	(2,582,636)	(2,764,489)	(2,571,365)
Deferred income taxes — net	$(2,723,425)	$(2,460,404)	$(2,764,489)	$(2,516,112)

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, 2015, 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2015, APS has recorded a regulatory liability of $2 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):

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2015	2014	2015	2014
DEFERRED TAX ASSETS				
Risk management activities	$70,498	$57,505	$70,498	$57,505
Regulatory liabilities:				
Asset retirement obligation and removal costs	216,765	229,772	216,765	229,772
Unamortized investment tax credits	100,779	96,232	100,779	96,232
Other postretirement benefits	83,034	90,496	83,034	90,496
Other	60,707	60,409	60,707	60,409
Pension liabilities	191,028	205,227	181,787	194,541
Renewable energy incentives	60,956	65,169	60,956	65,169
Credit and loss carryforwards	59,557	68,347	—	—
Other	149,033	138,729	176,016	161,379
Total deferred tax assets	992,357	1,011,886	950,542	955,503
DEFERRED TAX LIABILITIES				
Plant-related	(3,116,752)	(2,958,369)	(3,116,752)	(2,958,369)
Risk management activities	(10,626)	(12,171)	(10,626)	(12,171)
Other postretirement assets	(71,737)	(59,170)	(70,986)	(58,495)
Regulatory assets:				
Allowance for equity funds used during construction	(54,110)	(48,286)	(54,110)	(48,286)
Deferred fuel and purchased power	—	(2,498)	—	(2,498)
Deferred fuel and purchased power — mark-to-market	(55,020)	(38,187)	(55,020)	(38,187)
Pension benefits	(240,692)	(191,747)	(240,692)	(191,747)
Retired power plant costs (see Note 3)	(53,420)	(57,255)	(53,420)	(57,255)
Other	(108,441)	(99,123)	(108,441)	(99,123)
Other	(4,984)	(5,484)	(4,984)	(5,484)
Total deferred tax liabilities	(3,715,782)	(3,472,290)	(3,715,031)	(3,471,615)
Deferred income taxes — net	$(2,723,425)	$(2,460,404)	$(2,764,489)	$(2,516,112)

As of December 31, 2015, the deferred tax assets for credit and loss carryforwards relate primarily to federal general business credits of approximately $82 million, which first begin to expire in 2031, and other federal and state loss carryforwards of $3 million, which first begin to expire in 2019. The credit and loss carryforwards amount above has been reduced by $26 million of unrecognized tax benefits.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Lines of Credit and Short-Term Borrowings

Pinnacle West and APS maintain committed revolving credit facilities in order to enhance liquidity and provide credit support for their commercial paper programs, to refinance indebtedness, and for other general corporate purposes.

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2015 and 2014 (dollars in thousands):

	December 31, 2015			December 31, 2014		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facility	$200,000	$1,000,000	$1,200,000	$200,000	$1,000,000	$1,200,000
Outstanding Commercial Paper Borrowings	—	—	—	—	(147,400)	(147,400)
Amount of Credit Facility Available	$200,000	$1,000,000	$1,200,000	$200,000	$852,600	$1,052,600
Weighted-Average Commitment Fees	0.125%	0.100%		0.175%	0.125%	

Pinnacle West

At December 31, 2015, Pinnacle West had a $200 million revolving credit facility that matures in May 2019. 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, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

APS

On September 2, 2015, APS replaced its $500 million revolving credit facility that would have matured in April 2018, with a new $500 million facility that matures in September 2020.

At December 31, 2015, APS had two credit facilities totaling $1 billion, including the $500 million credit facility that matures in September 2020 and a $500 million credit facility that matures in May 2019. APS may increase the amount of each facility up to a maximum of $700 million each, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2015, APS had no outstanding borrowings or letters of credit under its revolving credit facilities. See "Financial Assurances" in Note 10 for a discussion of APS's other outstanding letters of credit.

Debt Provisions

On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved APS's short-term debt authorization equal to a sum of 7% of APS's capitalization, and $500 million (which is required to be used for costs relating to purchases of natural gas and power). This financing order is set to expire on December 31, 2017. See Note 6 for additional long-term debt provisions.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2015 and 2014 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2015	2014
APS				
Pollution control bonds:				
Variable	2029-2038	(b)	$92,405	$156,405
Fixed	2024-2034	1.75%-5.75%	211,150	249,300
Total pollution control bonds			303,555	405,705
Senior unsecured notes	2016-2045	2.20%-8.75%	3,375,000	2,875,000
Palo Verde sale leaseback lessor notes	2015	8.00%	—	13,420
Term loan	2018	(c)	50,000	—
Unamortized discount			(10,374)	(9,206)
Unamortized premium			4,686	4,866
Unamortized debt issuance cost	(d)		(27,896)	(24,642)
Total APS long-term debt			3,694,971	3,265,143
Less current maturities	(e)		357,580	383,570
Total APS long-term debt less current maturities			3,337,391	2,881,573
Pinnacle West				
Term loan	2017	(f)	125,000	125,000
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$3,462,391	$3,006,573

(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 0.01%-0.24% at December 31, 2015 and 0.03%-0.27% at December 31, 2014.

(c) The weighted-average interest rate was 1.024% at December 31, 2015.

(d) In the fourth quarter of 2015, we adopted a new accounting standard related to balance sheet presentation of debt issuance costs. See Note 2 for additional details.

(e) Current maturities include $108 million of pollution control bonds expected to be remarketed in 2016 and $250 million in senior unsecured notes that mature in 2016.

(f) The weighted-average interest rate was 1.174% at December 31, 2015 and 1.019% at December 31, 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 thousands):

Year	Consolidated Pinnacle West	Consolidated APS
2016	$ 357,580	$357,580
2017	125,000	—
2018	82,000	82,000
2019	500,000	500,000
2020	250,000	250,000
Thereafter	2,538,975	2,538,975
Total	$ 3,853,555	$3,728,555

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 thousands):

	As of December 31, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$125,000	$125,000	$125,000	$125,000
APS	3,694,971	3,981,367	3,265,143	3,714,108
Total	$3,819,971	$4,106,367	$3,390,143	$3,839,108

Credit Facilities and Debt Issuances

APS

On January 12, 2015, APS issued $250 million of 2.20% unsecured senior notes that mature on January 15, 2020. The net proceeds from the sale were used to repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On May 19, 2015, APS issued $300 million of 3.15% unsecured senior notes that mature on May 15, 2025. The net proceeds from the sale were used to repay short-term indebtedness consisting of commercial paper borrowings and drawings under our revolving credit facilities, incurred in connection with the payment at maturity of our $300 million aggregate principal amount of 4.65% notes due May 15, 2015.

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On June 26, 2015, APS entered into a $50 million term loan facility that matures June 26, 2018. Interest rates are based on APS's senior unsecured debt credit ratings. APS used the proceeds to repay and refinance existing short-term indebtedness.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On November 6, 2015, APS issued $250 million of 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance via redemption and cancellation at par our indebtedness related to the principal amounts of the Navajo County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A and 2009 Series C both due June 1, 2034, and repay commercial paper borrowings and replenish cash temporarily used to fund capital expenditures.

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2014.

On November 17, 2015, APS canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series B, purchased in connection with the mandatory tender provision on May 30, 2014.

On December 8, 2015, APS redeemed at par and canceled all $32 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series C.

See “Lines of Credit and Short-Term Borrowings” in Note 5 and “Financial Assurances” in Note 10 for discussion of APS’s separate outstanding letters of credit.

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, 2015, the ratio was approximately 47% for Pinnacle West and 46% 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 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.

An existing 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, 2015, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.6 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS's total capitalization remains the same. Since APS was in compliance with this common equity ratio requirement, this restriction does not materially affect Pinnacle West's ability to meet its ongoing capital requirements.

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 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 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. See Note 5 for additional short-term debt provisions.

7. Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan (The Pinnacle West Capital Corporation Retirement Plan) and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and its subsidiaries. All new employees participate in the account balance plan. Defined benefit plans specify the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. We calculate the benefits based on age, years of service and pay.

Pinnacle West also sponsors an other postretirement benefit plan (Pinnacle West Capital Corporation Group Life and Medical Plan) for the employees of Pinnacle West and its subsidiaries. This plan provides medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plan, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

On September 30, 2014, Pinnacle West announced plan design changes to the other postretirement benefit plan, which required an interim remeasurement of the benefit obligation for the plan. Effective January 1, 2015, those eligible retirees and dependents over age 65 and on Medicare can choose to be enrolled in a Health Reimbursement Arrangement (HRA). The Company will provide a subsidy allowing post-65 retirees to purchase a Medicare supplement plan on a private exchange network. The remeasurement of the benefit obligation included updating the assumptions. The remeasurement reduced net periodic benefit costs in 2014 by $10 million ($5 million of which reduced expense). The remeasurement also resulted in a decrease in Pinnacle West's other postretirement benefit obligation of $316 million, which was offset by the related regulatory asset and accumulated other comprehensive income.

Because of the plan changes, the Company is currently in the process of seeking IRS and regulatory approval to move approximately $100 million of the other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs.

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Pinnacle West uses a December 31 measurement date each year for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement date. See Note 13 for further discussion of how fair values are determined. Due to subjective and complex judgments, which may be required in determining fair values, actual results could differ from the results estimated through the application of these methods.

A significant portion of the changes in the actuarial gains and losses of our pension and postretirement plans is attributable to APS and therefore is recoverable in rates. Accordingly, these changes are recorded as a regulatory asset or regulatory liability. In its 2009 retail rate case settlement, APS received approval to defer a portion of pension and other postretirement benefit cost increases incurred in 2011 and 2012. We deferred pension and other postretirement benefit costs of approximately $14 million in 2012 and $11 million in 2011. Pursuant to an ACC regulatory order, we began amortizing the regulatory asset over three years beginning in July 2012. We amortized approximately $5 million in 2015, $8 million in 2014, $8 million in 2013 and $4 million in 2012.

The following table provides details of the plans' net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction, billed to electric plant participants or charged to the regulatory asset or liability) (dollars in thousands):

	Pension			Other Benefits		
	2015	2014	2013	2015	2014	2013
Service cost-benefits earned during the period	$59,627	$53,080	$64,195	$16,827	$18,139	$23,597
Interest cost on benefit obligation	123,983	129,194	112,392	28,102	41,243	41,536
Expected return on plan assets	(179,231)	(158,998)	(146,333)	(36,855)	(46,400)	(45,717)
Amortization of:						
Prior service cost (credit)	594	869	1,097	(37,968)	(9,626)	(179)
Net actuarial loss	31,056	10,963	39,852	4,881	1,175	11,310
Net periodic benefit cost	$36,029	$35,108	$71,203	$(25,013)	$4,531	$30,547
Portion of cost charged to expense	$20,036	$21,985	$38,968	$(10,391)	$6,000	$18,469

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the plans' changes in the benefit obligations and funded status for the years 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Change in Benefit Obligation				
Benefit obligation at January 1	$3,078,648	$2,646,530	$682,335	$890,418
Service cost	59,627	53,080	16,827	18,139
Interest cost	123,983	129,194	28,102	41,243
Benefit payments	(137,115)	(128,550)	(24,988)	(29,054)
Actuarial (gain) loss	(91,340)	378,394	(55,256)	150,188
Plan amendments	—	—	—	(388,599)
Benefit obligation at December 31	3,033,803	3,078,648	647,020	682,335
Change in Plan Assets				
Fair value of plan assets at January 1	2,615,404	2,264,121	834,625	748,339
Actual return on plan assets	(44,690)	292,992	(2,399)	105,223
Employer contributions	100,000	175,000	791	770
Benefit payments	(127,940)	(116,709)	—	(19,707)
Fair value of plan assets at December 31	2,542,774	2,615,404	833,017	834,625
Funded Status at December 31	$(491,029)	$(463,244)	$185,997	$152,290

The following table shows the projected benefit obligation and the accumulated benefit obligation for pension plans with an accumulated obligation in excess of plan assets as of December 31, 2015 and 2014 (dollars in thousands):

	2015	2014
Projected benefit obligation	$3,033,803	$3,078,648
Accumulated benefit obligation	2,873,467	2,873,741
Fair value of plan assets	2,542,774	2,615,404

The following table shows the amounts recognized on the Consolidated Balance Sheets as of December 31, 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Noncurrent asset	$—	$—	$185,997	$152,290
Current liability	(10,031)	(9,508)	—	—
Noncurrent liability	(480,998)	(453,736)	—	—
Net amount recognized	$(491,029)	$(463,244)	$185,997	$152,290

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The following table shows the details related to accumulated other comprehensive loss as of December 31, 2015 and 2014 (dollars in thousands):

	Pension		Other Benefits	
	2015	2014	2015	2014
Net actuarial loss	$679,501	$577,976	$127,124	$148,006
Prior service cost (credit)	609	1,203	(341,301)	(379,269)
APS's portion recorded as a regulatory (asset) liability	(619,223)	(485,037)	213,621	230,916
Income tax expense (benefit)	(23,663)	(36,890)	925	851
Accumulated other comprehensive loss	$37,224	$57,252	$369	$504

The following table shows the estimated amounts that will be amortized from accumulated other comprehensive loss and regulatory assets and liabilities into net periodic benefit cost in 2016 (dollars in thousands):

	Pension	Other Benefits
Net actuarial loss	$38,923	$3,784
Prior service cost (credit)	527	(37,884)
Total amounts estimated to be amortized from accumulated other comprehensive loss (gain) and regulatory assets (liabilities) in 2016	$39,450	$(34,100)

The following table shows the weighted-average assumptions used for both the pension and other benefits to determine benefit obligations and net periodic benefit costs:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,			
	2015	2014	2015	2014		2013
				January - September	October - December	
Discount rate – pension	4.37%	4.02%	4.02%	4.88%	4.88%	4.01%
Discount rate – other benefits	4.52%	4.14%	4.14%	5.10%	4.41%	4.20%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets - pension	N/A	N/A	6.90%	6.90%	6.90%	7.00%
Expected long-term return on plan assets - other benefits	N/A	N/A	4.45%	6.80%	4.25%	7.00%
Initial healthcare cost trend rate (pre-65 participants)	7.00%	7.00%	7.00%	7.50%	7.50%	7.50%
Initial healthcare cost trend rate (post-65 participants)	5.00%	5.00%	5.00%	7.50%	5.00%	7.50%
Ultimate healthcare cost trend rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Number of years to ultimate trend rate (pre-65 participants)	4	4	4	4	4	4
Number of years to ultimate trend rate (post-65 participants)	0	0	0	4	0	4

In selecting the pretax expected long-term rate of return on plan assets, we consider past performance and economic forecasts for the types of investments held by the plan. For 2016, we are assuming a 6.90% long-term rate of return for pension assets and 4.74% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

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In October 2014, the Society of Actuaries' Retirement Plans Experience Committee issued its final reports on its recommended mortality basis ("RP-2014 Mortality Tables Report" and "Mortality Improvement Scale MP-2014 Report"). At December 31, 2014, we updated our mortality assumptions using the recommended basis with modifications to better reflect our plan experience and additional data regarding mortality trends. The updated mortality assumptions resulted in a $67 million increase in Pinnacle West's pension and other postretirement obligations, which was offset by the related regulatory asset, regulatory liability and accumulated other comprehensive income.

In selecting our healthcare trend rates, we consider past performance and forecasts of healthcare costs. A one percentage point change in the assumed initial and ultimate healthcare cost trend rates would have the following effects (dollars in thousands):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$8,834	$(5,890)
Effect on service and interest cost components of net periodic other postretirement benefit costs	9,069	(6,949)
Effect on the accumulated other postretirement benefit obligation	100,322	(80,332)

Plan Assets

The Board of Directors has delegated oversight of the pension and other postretirement benefit plans' assets to an Investment Management Committee ("Committee"). The Committee has adopted investment policy statements ("IPS") for the pension and the other postretirement benefit plans' assets. The investment strategies for these plans include external management of plan assets, and prohibition of investments in Pinnacle West securities.

The overall strategy of the pension plan's IPS is to achieve an adequate level of trust assets relative to the benefit obligations. To achieve this objective, the plan's investment policy provides for mixes of investments including long-term fixed income assets and return-generating assets. The target allocation between return-generating and long-term fixed income assets is defined in the IPS and is a function of the plan's funded status. The plan's funded status is reviewed on at least a monthly basis.

Long-term fixed income assets, also known as liability-hedging assets, are designed to offset changes in the benefit obligations due to changes in interest rates. Long-term fixed income assets consist primarily of fixed income debt securities issued by the U.S. Treasury, other government agencies, and corporations. Long-term fixed income assets may also include interest rate swaps, U.S. Treasury futures and other instruments.

Return-generating assets are intended to provide a reasonable long-term rate of investment return with a prudent level of volatility. Return-generating assets are composed of U.S. equities, international equities, and alternative investments. International equities include investments in both developed and emerging markets. Alternative investments include investments in real estate, private equity and various other strategies. The plan may hold investments in return-generating assets by holding securities in partnerships and common and collective trusts.

Based on the IPS, and given the pension plan's funded status at year-end 2015, the long-term fixed income assets had a target allocation of 58% with a permissible range of 55% to 61% and the return-generating assets had a target allocation of 42% with a permissible range of 39% to 45%. The return-generating assets have additional target allocations, as a percent of total plan assets, of 22% equities in U.S. and other developed markets, 6% equities in emerging markets, and 14% in alternative investments. The pension plan IPS does not provide for a specific mix of long-term fixed income assets, but does expect the average credit quality of such assets to be investment grade. As of December 31, 2015, long-term fixed income assets represented 60% of total pension plan assets, and return-generating assets represented 40% of total pension plan assets.

As of December 31, 2015, the asset allocation for other postretirement benefit plan assets is governed by the IPS for those plans, which provides for different asset allocation target mixes depending on the characteristics of the liability. Some of these asset allocation target mixes vary with the plan's funded status. As of December 31, 2015, investment in fixed income assets represented 40% of the other postretirement benefit plan total assets, and non-fixed income assets represented 60% of the other postretirement benefit plan's assets. Fixed income assets are primarily invested in corporate bonds of investment-grade U.S. issuers, and U.S. Treasuries. Non-fixed income assets are primarily invested in large cap U.S. equities in diverse industries, and international equities in both emerging and developed markets.

See Note 13 for a discussion on the fair value hierarchy and how fair value methodologies are applied. The plans invest directly in fixed income and equity securities, in addition to investing indirectly in fixed income securities, equity securities and real estate through the use of mutual funds, partnerships and common and collective trusts. Equity securities held directly by the plans are valued using quoted active market prices from the published exchange on which the equity security trades, and are classified as Level 1. Fixed income securities issued by the U.S. Treasury held directly by the plans are valued using quoted active market prices, and are classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies are primarily valued using quoted inactive market prices, or quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield, maturity and credit quality. These instruments are classified as Level 2.

Mutual funds, partnerships, and common and collective trusts are valued utilizing a net asset value (NAV) concept or its equivalent. Exchange traded mutual funds, are classified as Level 1, as the valuation for these instruments is based on the active market in which the fund trades.

Common and collective trusts, are maintained by banks or investment companies and hold certain investments in accordance with a stated set of objectives (such as tracking the performance of the S&P 500 Index). The trust's shares are offered to a limited group of investors, and are not traded in an active market. The NAV for trusts investing in exchange traded equities is derived from the quoted active market prices of the underlying securities held by the trusts. The NAV for trusts investing in real estate is derived from the appraised values of the trust's underlying real estate assets. As of December 31, 2015, the plans were able to transact in the common and collective trusts at NAV and classifies these investments as Level 2.

Investments in partnerships are also valued using the concept of NAV, which is derived from the value of the partnerships' underlying assets. The plan's partnerships holdings relate to investments in high-yield fixed income instruments and assets of privately held portfolio companies. Certain partnerships also include funding commitments that may require the plan to contribute up to $75 million to these partnerships; as of December 31, 2015, approximately $40 million of these commitments have been funded. Partnerships are classified as Level 2 if the plan is able to transact in the partnership at the NAV, otherwise the partnership is classified as Level 3.

The plans' trustee provides valuation of our plan assets by using pricing services that utilize methodologies described to determine fair market value. We have internal control procedures to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market

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transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes.

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2015, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (b)	Balance at December 31, 2015
Pension Plan:					
Assets:					
Cash and cash equivalents	$1,893	$—	$—	$—	$1,893
Fixed income securities:					
Corporate	—	1,108,736	—	—	1,108,736
U.S. Treasury	274,778	—	—	—	274,778
Other (a)	—	113,008	—	—	113,008
Equities:					
U.S. companies	233,021	—	—	—	233,021
International companies	14,680	—	—	—	14,680
Common and collective trusts:					
U.S. equities	—	130,097	—	—	130,097
International equities	—	185,892	—	—	185,892
Real estate	—	150,359	—	—	150,359
Partnerships	—	127,840	42,097	—	169,937
Mutual funds - International equities	116,307	—	—	—	116,307
Short-term investments and other	—	29,599	—	14,467	44,066
Total Pension Plan	$640,679	$1,845,531	$42,097	$14,467	$2,542,774
Other Benefits:					
Assets:					
Cash and cash equivalents	$240	$—	$—	$—	$240
Fixed income securities:					
Corporate	—	217,026	—	—	217,026
U.S. Treasury	131,435	—	—	—	131,435
Other (a)	—	31,106	—	—	31,106
Equities:					
U.S. companies	253,193	—	—	—	253,193
International companies	12,390	—	—	—	12,390
Common and collective trusts:					
U.S. equities	—	81,516	—	—	81,516
International equities	—	28,539	—	—	28,539
Real estate	—	13,512	—	—	13,512

Mutual funds - International equities	52,568	—	—	—	52,568
Short-term investments and other	5,065	3,331	—	3,096	11,492
Total Other Benefits	$454,891	$375,030	$—	$3,096	$833,017

(a) This category consists primarily of debt securities issued by municipalities.
(b) Represents plan receivables and payables.

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The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2014, by asset category, are as follows (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (b)	Balance at December 31, 2014
Pension Plan:					
Assets:					
Cash and cash equivalents	$387	$—	$—	$—	$387
Fixed Income Securities:					
Corporate	—	1,162,096	—	—	1,162,096
U.S. Treasury	291,817	—	—	—	291,817
Other (a)	—	113,265	—	—	113,265
Equities:					
U.S. Companies	246,387	—	—	—	246,387
International Companies	18,069	—	—	—	18,069
Common and collective trusts:					
U.S. Equities	—	127,336	—	—	127,336
International Equities	—	317,167	—	—	317,167
Real estate	—	129,715	—	—	129,715
Partnerships	—	138,337	27,929	—	166,266
Short-term investments and other	—	26,016	—	16,883	42,899
Total Pension Plan	$556,660	$2,013,932	$27,929	$16,883	$2,615,404
Other Benefits:					
Assets:					
Cash and cash equivalents	$318	$—	$—	$—	$318
Fixed Income Securities:					
Corporate	—	187,961	—	—	187,961
U.S. Treasury	130,967	—	—	—	130,967
Other (a)	—	35,291	—	—	35,291
Equities:					
U.S. Companies	265,106	—	—	—	265,106
International Companies	17,813	—	—	—	17,813
Common and collective trusts:					
U.S. Equities	—	88,258	—	—	88,258
International Equities	—	85,746	—	—	85,746
Real Estate	—	11,657	—	—	11,657
Short-term investments and other	—	7,408	—	4,100	11,508
Total Other Benefits	$414,204	$416,321	$—	$4,100	$834,625

(a) This category consists primarily of debt securities issued by municipalities.
(b) Represents plan receivables and payables.

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The following table shows the changes in fair value for assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2015 and 2014 (dollars in thousands):

	Pension	
Partnerships	2015	2014
Beginning balance at January 1	$27,929	$8,660
Actual return on assets still held at December 31	2,789	927
Purchases	13,187	19,984
Sales	(1,808)	(1,642)
Transfers in and/or out of Level 3	—	—
Ending balance at December 31	$42,097	$27,929

Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $100 million in 2015, $175 million in 2014, and $141 million in 2013. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2016-2018 period. With regard to contributions to our other postretirement benefit plans, we made a contribution of $1 million in 2015, $1 million in 2014, and $14 million in 2013. We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans. APS funds its share of the contributions. APS's share of the pension plan contribution was $100 million in 2015, $175 million in 2014, and $140 million in 2013. APS's share of the contributions to the other postretirement benefit plan was $1 million in 2015, $1 million in 2014, and $14 million in 2013.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter, are estimated to be as follows (dollars in thousands):

Year	Pension	Other Benefits
2016	$152,146	$ 26,468
2017	171,005	28,444
2018	170,534	30,490
2019	180,700	32,438
2020	188,988	33,982
Years 2021-2025	1,023,451	184,335

Electric plant participants contribute to the above amounts in accordance with their respective participation agreements.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and its subsidiaries. In 2015, costs related to APS's employees represented 99% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account, the Company's matching contributions and earnings or losses on their investments. Under this plan, the Company matches a percentage of the participants' contributions in cash which is then invested in the same investment mix as participants elect to invest their own

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future contributions. Pinnacle West recorded expenses for this plan of approximately $9 million for 2015, $9 million for 2014, and $9 million for 2013.

8. Leases

We lease certain vehicles, land, buildings, equipment and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Consolidated Statements of Income was $17 million in 2015, $18 million in 2014, and $18 million in 2013. APS's lease expense was $14 million in 2015, $15 million in 2014, and $15 million in 2013.

Estimated future minimum lease payments for Pinnacle West's and APS's operating leases, excluding purchased power agreements, are approximately as follows (dollars in thousands):

Year	Pinnacle West Consolidated	APS
2016	$ 9,182	$ 8,797
2017	8,557	8,317
2018	7,045	6,880
2019	6,121	5,961
2020	4,835	4,680
Thereafter	61,251	61,101
Total future lease commitments	$ 96,991	$ 95,736

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lessor trust entities have been deemed VIEs for which APS is the primary beneficiary. As the primary beneficiary, APS consolidated these lessor trust entities. The impacts of these sale leaseback transactions are excluded from our lease disclosures as lease accounting is eliminated upon consolidation. See Note 18 for a discussion of VIEs.

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9. Jointly-Owned Facilities

APS shares ownership of some of its generating and transmission facilities with other companies. We are responsible for our share of operating costs which are included in the corresponding operating expenses on our consolidated statement of income. We are also responsible for providing our own financing. Our share of operating expenses and utility plant costs related to these facilities is accounted for using proportional consolidation. The following table shows APS's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2015 (dollars in thousands):

	Percent Owned			Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:						
Palo Verde Units 1 and 3	29.1	%		$1,744,137	$1,067,376	$22,228
Palo Verde Unit 2 (a)	16.8	%		583,633	356,767	4,142
Palo Verde Common	28.0	%	(b)	643,201	231,609	64,069
Palo Verde Sale Leaseback			(a)	351,050	233,665	—
Four Corners Generating Station	63.0	%		857,555	577,321	77,317
Navajo Generating Station Units 1, 2 and 3	14.0	%		274,640	168,132	4,460
Cholla common facilities (c)	63.3	%	(b)	158,623	53,777	1,390
Transmission facilities:						
ANPP 500kV System	33.4	%	(b)	109,348	36,576	1,594
Navajo Southern System	22.7	%	(b)	62,139	19,361	397
Palo Verde — Yuma 500kV System	19.3	%	(b)	14,043	5,226	133
Four Corners Switchyards	49.8	%	(b)	38,420	9,833	1,687
Phoenix — Mead System	17.1	%	(b)	39,089	13,173	151
Palo Verde — Estrella 500kV System	50.0	%	(b)	89,832	18,359	1,008
Morgan — Pinnacle Peak System	64.6	%	(b)	129,855	11,087	2,592
Round Valley System	50.0	%	(b)	703	286	—
Palo Verde — Morgan System	87.7	%	(b)	12	—	133,813
Hassayampa - North Gila System	80.0	%	(b)	164,854	1,159	—
Cholla 500 Switchyard	85.7	%	(b)	547	15	—
Saguaro 500 Switchyard	75.0	%	(b)	773	26	—

(a) See Note 18.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.

10. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

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 DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo

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Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of current reported net income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through 2016.

APS's first claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2011 through June 30, 2014, and was for $42.0 million (APS's share of this amount was $12.2 million), was received on June 1, 2015. APS's $12.2 million share was recorded as an adjustment to a regulatory liability and had no impact on the amount of current reported net income. APS's second claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2014 through June 30, 2015, was filed for $12.0 million (APS's share of this amount would be $3.6 million), and has been submitted to, but not yet approved by, the DOE in the fourth quarter of 2015.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to $13.5 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $375 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of $13.1 billion of liability coverage is provided through a mandatory industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum retrospective premium assessment per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to an annual limit of $19 million per incident, to be periodically adjusted for inflation. Based on APS's ownership interest in the three Palo Verde units, APS's maximum potential retrospective premium assessment per incident for all three units is approximately $111 million, with a maximum annual retrospective premium assessment of approximately $16.6 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of replacement generation or purchased power and business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium assessments under all NEIL policies if NEIL's losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $23.1 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $61.7 million of collateral assurance within 20 business days of a rating downgrade to non-investment grade. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions, sublimits and exclusions.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fuel and Purchased Power Commitments and Purchase Obligations

APS is party to various fuel and purchased power contracts and purchase obligations with terms expiring between 2016 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $876 million in 2016; $949 million in 2017; $737 million in 2018; $603 million in 2019; $498 million in 2020; and $7.8 billion thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various fuel and purchased power contracts mentioned above, some of those contracts for coal supply include take-or-pay provisions. The current coal contracts with take-or-pay provisions have terms expiring through 2031.

The following table summarizes our estimated coal take-or-pay commitments (dollars in thousands):

	Years Ended December 31,					
	2016	2017	2018	2019	2020	Thereafter
Coal take-or-pay commitments (a)	$170,714	$195,428	$189,588	$193,818	$198,160	$2,270,974

(a) Total take-or-pay commitments are approximately $3.2 billion. The total net present value of these commitments is approximately $2.2 billion.

APS may spend more to meet its actual fuel requirements than the minimum purchase obligations in our coal take-or-pay contracts. The following table summarizes actual payments under the coal contracts which include take-or-pay provisions for each of the last three years (dollars in thousands):

	Year Ended December 31,		
	2015	2014	2013
Total payments	$211,327	$236,773	$188,496

Renewable Energy Credits

APS has entered into contracts to purchase renewable energy credits to comply with the RES. APS estimates the contract requirements to be approximately $42 million in 2016; $40 million in 2017; $40 million in 2018; $40 million in 2019; $40 million in 2020; and $432 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for final and contemporaneous coal mine reclamation. We account for contemporaneous reclamation costs as part of the cost of the delivered coal. We utilize site-specific studies of costs expected to be incurred in the future to estimate our final reclamation obligation. These studies utilize various assumptions to estimate the future costs. Based on the most recent reclamation studies, APS recorded an obligation for the coal mine final reclamation of approximately $202 million at December 31, 2015 and $198 million at December 31, 2014. Under our current coal supply agreements, we expect to make payments for the final mine reclamation as follows: $15 million in 2016; $16 million in 2017; $18 million in 2018; $19 million in

2019; $20 million in 2020; and $262 million thereafter. Any amendments to current coal supply agreements may change the timing of the contribution. Portions of

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these funds will be held in an escrow account and distributed to certain coal providers under the terms of the applicable coal supply agreements.

Superfund-Related Matters

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 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, 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, 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. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Southwest Power Outage

On September 8, 2011 at approximately 3:30 PM, a 500 kV transmission line running between the Hassayampa and North Gila substations in southwestern Arizona tripped out of service due to a fault that occurred at a switchyard operated by APS. Approximately ten minutes after the transmission line went off-line, generation and transmission resources for the Yuma area were lost, resulting in approximately 69,700 APS customers losing service.

On September 6, 2013, a purported consumer class action complaint was filed in Federal District Court in San Diego, California, naming APS and Pinnacle West as defendants and seeking damages for loss of perishable inventory and sales as a result of interruption of electrical service. APS and Pinnacle West filed a motion to dismiss, which the court granted on December 9, 2013. On January 13, 2014, the plaintiffs appealed the lower court's decision. The appeal is now fully briefed and pending before the United States Court of Appeals for the Ninth Circuit, which heard oral argument on February 9, 2016. A written decision on the case is expected 30-60 days after oral argument. We believe the District Court's decision will be upheld on appeal, but cannot predict the outcome at the appellate court. If the District Court's decision is reversed, the case would be remanded for discovery and trial, and there is insufficient information at this time to reasonably estimate any possible loss or range of loss to APS and Pinnacle West.

Clean Air Act Citizen Lawsuit

On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New 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 a First Amended Complaint adding claims for violations of the Clean Air Act's NSPS program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

The settlement requires installation of pollution control technology and implementation of other measures to reduce sulfur dioxide and nitrogen oxide emissions from the two Four Corners units, although installation of much of this equipment was already planned in order to comply with EPA's Regional Haze Rule requirements. The settlement also requires the Four Corners co-owners to pay a civil penalty of $1.5 million and spend $6.7 million for certain environmental mitigation projects to benefit the Navajo Nation. APS is responsible for 15 percent of these costs based on its ownership interest in the units at the time of the alleged violations, which does not result in a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, wastewater discharges, solid waste, hazardous waste, and CCRs. These laws and regulations can change from time to time, imposing new obligations on APS resulting in increased capital, operating, and other costs. Associated capital expenditures or operating costs could be material. APS intends to seek recovery of any such environmental compliance costs through our rates, but cannot predict whether it will obtain such recovery. The following proposed and final rules involve material compliance costs to APS.

Regional Haze Rules. APS has received the final rulemaking imposing new requirements on Four Corners, Cholla and 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.

Four Corners. Based on EPA's final standards, APS estimates that its 63% share of the cost of these controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC has the option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. In December 2015, NTEC notified APS of its intent to exercise the option. APS is negotiating a definitive purchase agreement with NTEC for the purchase of the 7% interest. The cost of the pollution controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

Navajo Plant. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this review process.

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Cholla. APS believes that EPA's final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), 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. Briefing in the case was completed in February 2014.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015. On October 16, 2015, ADEQ issued the Cholla permit, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. APS is unable to predict when or whether APS's proposal may ultimately be approved by the EPA.

Mercury and Air Toxic Standards ("MATS"). In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015). 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, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in Michigan vs. EPA reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

Because the Subtitle D rule is self-implementing, the CCR standards apply directly to the regulated facility, and facilities are directly responsible for ensuring that their operations comply with the rule's requirements. While EPA has chosen to regulate the disposal of CCR in landfills and surface impoundments as non-hazardous waste under the final rule, the agency makes clear that it will continue to evaluate any risks associated with CCR disposal and leaves open the possibility that it may regulate CCR as a hazardous waste under RCRA Subtitle C in the future.

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $15 million, and its share of incremental costs for Cholla is approximately $85 million. The Navajo Plant currently disposes of CCR in a dry landfill storage area. APS estimates that its share of incremental costs to comply with the CCR rule for the Navajo Plant is approximately $1 million.

Clean Power Plan. On August 3, 2015, EPA finalized carbon pollution standards for existing, new, modified, and reconstructed EGUs. EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal.

With respect to existing power plants, EPA's recently finalized "Clean Power Plan" imposes state-specific goals or targets to achieve reductions in CO_2 emission rates from existing EGUs measured from a 2012 baseline. In a significant change from the proposed rule, EPA's final performance standards apply directly to specific units based upon their fuel-type and configuration (i.e., coal- or oil-fired steam plants versus combined cycle natural gas plants). As such, each state's goal is an emissions performance standard that reflects the fuel mix employed by the EGUs in operation in those states. The final rule provides guidelines to states to help develop their plans for meeting the interim (2022-2029) and final (2030 and beyond) emission performance standards, with three distinct compliance periods within that timeframe. States were originally required to submit their plans to EPA by September 2016, with an optional two-year extension provided to states establishing a need for additional time; however, it is expected that this timing will be impacted by the court-imposed stay described below.

ADEQ, with input from a technical working group comprised of Arizona utilities and other stakeholders, is presently working to develop a compliance plan for submittal to EPA. In addition to these on-going state proceedings, EPA has taken public comments on proposed model rules and a proposed federal compliance plan, which included consideration as to how the Clean Power Plan will apply to EGUs on tribal land such as the Navajo Nation.

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit; the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such delay.

With respect to our Arizona generating units, we are currently evaluating the range of compliance options available to ADEQ, including whether Arizona deploys a rate- or mass-based compliance plan. Based on the fuel-mix and location of our Arizona EGUs, and the significant investments we have made in renewable generation and demand-side energy efficiency, if ADEQ selects a rate-based compliance plan, we believe that we will be able to comply with the Clean Power Plan for our Arizona generating units in a manner that will not have material financial or operational impacts to the Company. On the other hand, if ADEQ selects a mass-based approach to compliance with the Clean Power Plan, our annual cost of compliance could be material. These costs could include costs to acquire mass-based compliance allowances.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As to our facilities on the Navajo Nation, EPA has yet to determine whether or to what extent EGUs on the Navajo Nation will be required to comply with the Clean Power Plan. EPA has proposed to determine that it is necessary or appropriate to impose a federal plan on the Navajo Nation for compliance with the Clean Power Plan. In response, we filed comments with EPA advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. If EPA reaches a determination that is consistent with our preferred approach for the Navajo Nation, we believe the Clean Power Plan will not have material financial or operational impacts on our operations within the Navajo Nation.

Alternatively, if EPA determines that a federal plan is necessary or appropriate for the Navajo Nation, and depending on our need for future operations at our EGUs located there, we may be unable to comply with the federal plan unless we acquire mass-based allowances or emission rate credits within established carbon trading markets, or curtail our operations. Subject to the uncertainties set forth below, and assuming that EPA establishes a federal plan for the Navajo Nation that requires carbon allowances or credits to be surrendered for plan compliance, it is possible we will be required to purchase some quantity of credits or allowances, the cost of which could be material.

Because ADEQ has not issued its plan for Arizona, and because we do not know whether EPA will decide to impose a plan or, if so, what that plan will require, there are a number of uncertainties associated with our potential cost exposure. These uncertainties include: whether judicial review will result in the Clean Power Plan being vacated in whole or in part or, if not, the extent of any resulting compliance deadline delays; whether any plan will be imposed for EGUs on the Navajo Nation; the future existence and liquidity of allowance or credit compliance trading markets; the applicability of existing contractual obligations with current and former owners of our participant-owned coal-fired EGUs; the type of federal or state compliance plan (either rate- or mass-based); whether or not the trading of allowances or credits will be authorized mechanisms for compliance with any final EPA or ADEQ plan; and how units that have been closed will be treated for allowance or credit allocation purposes.

In the event that the incurrence of compliance costs is not economically viable or prudent for our operations in Arizona or on the Navajo Nation, or if we do not have the option of acquiring allowances to account for the emissions from our operations, we may explore other options, including reduced levels of output, as an alternative to purchasing allowances. Given these uncertainties, our analysis of the available compliance options remains on-going, and additional information or considerations may arise that change our expectations.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard, greenhouse gas emissions, and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, 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.

Notice of Intent to Sue Related to Four Corners

On December 21, 2015, several environmental groups filed a notice of intent to sue with OSM and other federal agencies under the Endangered Species Act alleging that OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the DOI's review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. We are monitoring this matter and will intervene if a lawsuit is filed. We cannot predict the timing or outcome of this matter.

New Mexico Tax Matter

On May 23, 2013, the New Mexico Taxation and Revenue Department ("NMTRD") issued a notice of assessment for coal severance surtax, penalty, and interest totaling approximately $30 million related to coal supplied under the coal supply agreement for Four Corners (the "Assessment"). APS's share of the Assessment is approximately $12 million. For procedural reasons, on behalf of the Four Corners co-owners, including APS, the coal supplier made a partial payment of the Assessment and immediately filed a refund claim with respect to that partial payment in August 2013. The NMTRD denied the refund claim. On December 19, 2013, the coal supplier and APS, on its own behalf and as operating agent for Four Corners, filed a complaint with the New Mexico District Court contesting both the validity of the Assessment and the refund claim denial. On June 30, 2015, the court ruled that the Assessment was not valid and further ruled that APS and the other Four Corners co-owners receive a refund of all of the contested amounts previously paid under the applicable tax statute. The NMTRD filed an appeal of the decision on August 31, 2015. The parties are engaged in settlement discussions and we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support certain debt arrangements, commodity contract collateral obligations, and other transactions. As of December 31, 2015, standby letters of credit totaled $79 million and will expire in 2016. As of December 31, 2015, surety bonds expiring through 2018 totaled $158 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

We enter into agreements that include indemnification provisions relating to liabilities arising from or related to certain of our agreements. Most significantly, APS has agreed to indemnify the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnification provisions is likely.

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at December 31, 2015.

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11. Asset Retirement Obligations

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets.

The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term and coal ash pond closures. Some of APS's transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such transmission and distribution assets. Additionally, APS has aquifer protection permits for some of its generation sites that require the closure of certain facilities at those sites.

In 2015, a revision to the estimated cash flows for the decommissioning study was completed for the Four Corners coal-fired plant, which resulted in an increase to the ARO in the amount of $24 million. Also in 2015, Four Corners spent $32 million in actual decommissioning costs. In addition, APS recognized an ARO for Cholla as a result of new CCR environmental rules that were published in the Federal Register in the second quarter of 2015. See Note 10 for additional information related to the CCR environmental rules. This resulted in an increase to the ARO in the amount of $39 million, an increase in plant in service of $23 million and a reduction of the regulatory liability of $16 million. Finally, in 2015 there was a revision in estimated cash flows for the Cholla decommissioning, which resulted in a decrease of the ARO in the amount of $3 million.

In 2014, an update to the 2013 decommissioning study was completed for Palo Verde nuclear generation facility to incorporate additional spent fuel related charges resulting in an increase to the ARO in the amount of $20 million. Also in 2014, an updated Four Corners Units 1-3 coal-fired power plant decommissioning study was finalized, which resulted in an increase to the ARO of $24 million. In addition, Four Corners spent $30 million in actual decommissioning costs. Finally, in 2014 APS also recognized an ARO related to a new solar facility on leased property that requires the land to be returned to its original condition upon decommissioning of the plant, which resulted in an increase to the ARO of $6 million.

The following table shows the change in our asset retirement obligations for 2015 and 2014 (dollars in thousands):

	2015	2014
Asset retirement obligations at the beginning of year	$390,750	$346,729
Changes attributable to:		
Accretion expense	25,163	23,567
Settlements	(32,048)	(29,497)
Estimated cash flow revisions	17,556	43,899
Newly incurred obligation	42,155	6,052
Asset retirement obligations at the end of year	$443,576	$390,750

As mentioned above, decommissioning activities for Four Corners Units 1-3 began in January 2014. Decommissioning activities for Cholla ash ponds began in January 2015. Thus, $29 million of the total ARO of $444 million at December 31, 2015, is classified as a current liability on the balance sheet. At December 31, 2014, $32 million of the total ARO of $391 million was classified as a current liability on the balance sheet.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 3.

12. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2015 and 2014 is provided in the tables below (dollars in thousands, except per share amounts). Weather conditions cause significant seasonal fluctuations in our revenues; therefore, results for interim periods do not necessarily represent results expected for the year.

	2015 Quarter Ended				2015
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$671,219	$890,648	$1,199,146	$734,430	$3,495,443
Operations and maintenance	214,944	210,965	220,449	222,019	868,377
Operating income	67,684	231,973	445,111	109,834	854,602
Income taxes	7,947	67,371	139,555	22,847	237,720
Net income	20,727	127,507	261,978	45,978	456,190
Net income attributable to common shareholders	16,122	122,902	257,116	41,117	437,257
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$0.15	$1.11	$2.32	$0.37	$3.94
Net income attributable to common shareholders — Diluted	0.14	1.10	2.30	0.37	3.92

	2014 Quarter Ended				2014
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$686,251	$906,264	$1,172,667	$726,450	$3,491,632
Operations and maintenance	212,882	211,222	223,418	260,503	908,025
Operating income	75,170	254,113	421,775	60,184	811,242
Income taxes	6,405	74,540	134,753	5,007	220,705
Net income	24,691	141,384	248,086	9,535	423,696
Net income attributable to common shareholders	15,766	132,458	243,961	5,410	397,595
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$0.14	$1.20	$2.20	$0.05	$3.59
Net income attributable to common shareholders — Diluted	0.14	1.19	2.20	0.05	3.58

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Selected Quarterly Financial Data (Unaudited) - APS

APS's quarterly financial information for 2015 and 2014 is as follows (dollars in thousands):

	2015 Quarter Ended,				2015
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$670,668	$889,723	$ 1,198,380	$ 733,586	$3,492,357
Operations and maintenance	209,947	208,031	216,011	219,146	853,135
Operating income	61,333	162,704	301,238	86,709	611,984
Net income attributable to common shareholder	19,868	125,362	261,187	43,857	450,274

	2014 Quarter Ended,				2014
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$685,545	$905,578	$ 1,172,190	$ 725,633	$3,488,946
Operations and maintenance	208,285	208,059	212,430	253,668	882,442
Operating income	69,635	180,394	287,928	54,835	592,792
Net income attributable to common shareholder	19,518	134,916	251,047	15,738	421,219

13. Fair Value Measurements

We classify our assets and liabilities that are carried at fair value within the fair value hierarchy. This hierarchy ranks the quality and reliability of the inputs used to determine fair values, which are then classified and disclosed in one of three categories. The three levels of the fair value hierarchy are:

Level 1 — Unadjusted quoted prices in active markets for identical assets or liabilities that we have the ability to access at the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide information on an ongoing basis. This category includes exchange traded equities, exchange traded derivative instruments, exchange traded mutual funds, cash equivalents, and investments in U.S. Treasury securities.

Level 2 — Utilizes quoted prices in active markets for similar assets or liabilities; quoted prices in markets that are not active; and model-derived valuations whose inputs are observable (such as yield curves). This category includes non-exchange traded contracts such as forwards, options, swaps and certain investments in fixed income securities. This category also includes certain investments that are valued and redeemable based on NAV, such as common and collective trusts and commingled funds.

Level 3 — Valuation models with significant unobservable inputs that are supported by little or no market activity. Instruments in this category include long-dated derivative transactions where valuations are unobservable due to the length of the transaction, options, and transactions in locations where observable market data does not exist. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market

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information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust and plan assets held in our retirement and other benefit plans. See Note 7 for the fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent short-term investments with original maturities of three months or less in exchange traded money market funds that are valued using quoted prices in active markets.

Risk Management Activities — Derivative Instruments

Exchange traded commodity contracts are valued using unadjusted quoted prices. For non-exchange traded commodity contracts, we calculate fair value based on the average of the bid and offer price, discounted to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed out or hedged. The credit valuation adjustment represents estimated credit losses on our net exposure to counterparties, taking into account netting agreements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. We maintain credit policies that management believes minimize overall credit risk.

Certain non-exchange traded commodity contracts are valued based on unobservable inputs due to the long-term nature of contracts, characteristics of the product, or the unique location of the transactions. Our long-dated energy transactions consist of observable valuations for the near-term portion and unobservable valuations for the long-term portions of the transaction. We rely primarily on broker quotes to value these instruments. When our valuations utilize broker quotes, we perform various control procedures to ensure the quote has been developed consistent with fair value accounting guidance. These controls include assessing the quote for reasonableness by comparison against other broker quotes, reviewing historical price relationships, and assessing market activity. When broker quotes are not available, the primary valuation technique used to calculate the fair value is the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at more illiquid delivery points.

Option contracts are primarily valued using a Black-Scholes option valuation model, which utilizes both observable and unobservable inputs such as broker quotes, interest rates and price volatilities.

When the unobservable portion is significant to the overall valuation of the transaction, the entire transaction is classified as Level 3. Our classification of instruments as Level 3 is primarily reflective of the long-term nature of our energy transactions and the use of option valuation models with significant unobservable inputs.

Our energy risk management committee, consisting of officers and key management personnel, oversees our energy risk management activities to ensure compliance with our stated energy risk management policies. We have a risk control function that is responsible for valuing our derivative commodity instruments in accordance with established policies and procedures. The risk control function reports to the chief financial officer's organization.

Investments Held in our Nuclear Decommissioning Trust

The nuclear decommissioning trust invests in fixed income securities and equity securities. Equity securities are held indirectly through commingled funds. The commingled funds are valued based on the concept of NAV, which is a value primarily derived from the quoted active market prices of the underlying equity securities. We may transact in these commingled funds on a semi-monthly basis at the NAV. We classify these investments as Level 2. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

Cash equivalents reported within Level 1 represent investments held in a short-term investment exchange-traded mutual fund, which invests in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, and commercial paper.

Fixed income securities issued by the U.S. Treasury held directly by the nuclear decommissioning trust are valued using quoted active market prices and are typically classified as Level 1. Fixed income securities issued by corporations, municipalities, and other agencies, including mortgage-backed instruments, are valued using quoted inactive market prices, quoted active market prices for similar securities, or by utilizing calculations which incorporate observable inputs such as yield curves and spreads relative to such yield curves. These instruments are classified as Level 2. Whenever possible, multiple market quotes are obtained which enables a cross-check validation. A primary price source is identified based on asset type, class, or issue of securities.

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes. See Note 19 for additional discussion about our nuclear decommissioning trust.

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Fair Value Tables

The following table presents the fair value at December 31, 2015 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at December 31, 2015
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$—	$22,992	$30,364	$(25,345)	(b)	$28,011
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	314,957	—	—		314,957
Fixed income securities:						
Cash and cash equivalent funds	12,260	—	—	(335)	(c)	11,925
U.S. Treasury	117,245	—	—	—		117,245
Corporate debt	—	96,243	—	—		96,243
Mortgage-backed securities	—	99,065	—	—		99,065
Municipal bonds	—	72,206	—	—		72,206
Other	—	23,555	—	—		23,555
Subtotal nuclear decommissioning trust	129,505	606,026	—	(335)		735,196
Total	$129,505	$629,018	$30,364	$(25,680)		$763,207
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$—	$(144,044)	$(63,343)	$39,698	(b)	$(167,689)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral. See Note 16.
(c) Represents nuclear decommissioning trust