PINNACLE WEST CAPITAL CORP
Form 10-K
February 22, 2019

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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, 2018

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 every Interactive Data File required to be submitted 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 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, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and "emerging growth 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	Smaller reporting company o
	Emerging growth company

ARIZONA PUBLIC SERVICE COMPANY

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x	Smaller reporting company o
	Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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	$9,020,511,769.84 as of June 30, 2018
ARIZONA PUBLIC SERVICE COMPANY	$0 as of June 30, 2018

The number of shares outstanding of each registrant’s common stock as of February 15, 2019

PINNACLE WEST CAPITAL CORPORATION	112,146,511 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 15, 2019 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.

Table of Contents

TABLE OF CONTENTS

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.

i

GLOSSARY OF NAMES AND TECHNICAL TERMS

4CA	4C Acquisition, LLC, a subsidiary of the Company
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
ASU	Accounting Standards Update
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
DSM	Demand side management
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 Generating Station or PVGS
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
TCA	Transmission cost adjustor
TEAM	Tax expense adjustor mechanism
VIE	Variable interest entity

Table of Contents

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," "project" and similar words. Because ac 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" of this report, 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, seasonality, 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, ballot initiatives and regulation, including those relating to environmental requirements, regulatory policy, 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, economic 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, and in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" 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.

Table of Contents

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, BCE and 4CA. 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 6,015 MW of regulated generation capacity (which is expected to increase by 510 MW upon completion of the Ocotillo Modernization Project by the middle of 2019) 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 2018, no single purchaser or user of energy accounted for more than 2.7% of our electric revenues.

Table of Contents

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

Table of Contents

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 2018 were as follows:

Generation Facilities

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

Coal-Fueled Generating Facilities

Four Corners — Four Corners is located in the northwestern corner of New Mexico, and was originally a 5-unit coal-fired power plant. APS owns 100% of Units 1, 2 and 3, which were retired as of December 30, 2013. APS operates the plant and owns 63% of Four Corners Units 4 and 5 following the acquisition of SCE's interest in Units 4 and 5 described below. APS has a total entitlement from Four Corners of 970 MW. Additionally, 4CA, a wholly-owned subsidiary of Pinnacle West, owned 7% of Units 4 and 5 from July 2016 through July 2018 following its acquisition of El Paso's interest in these units described below.

On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal

Table of Contents

supplier and operator of the mine that served 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. 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 through 2031 (the "2016 Coal Supply Agreement"). El Paso, a 7% owner of Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. (See Note 10 for a discussion of certain matters related to the 2016 Coal Supply Agreement.) 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. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

NTEC had the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. Concurrent with the settlement of the 2016 Coal Supply Agreement matter described in Note 10, NTEC and 4CA agreed to allow for the purchase by NTEC of the 7% interest, consistent with the option. On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. Completion of the sale was subject to the receipt of approval by FERC, which was received on July 2, 2018, and the sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and will pay 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. Such payments are due to 4CA at the end of each calendar year. A $10 million payment was due to 4CA at December 31, 2017, which NTEC satisfied by directing to 4CA a prepayment from APS of a portion of a future mine reclamation obligation. The balance of the amount under this formula due December 31, 2018 for calendar year 2017 is approximately $20 million, which was paid to 4CA on December 14, 2018. The balance of the amount under this formula at December 31, 2018 for calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which is due to 4CA at December 31, 2019.

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 of decision on July 17, 2015 justifying the agency action extending the life of the plant and the adjacent mine.

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA") in providing the

5

federal approvals necessary to extend operations at Four Corners and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. Oral argument for this appeal has been scheduled for March 2019. We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

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, which was later addressed in the March 27, 2017 settlement agreement regarding APS's general retail case (the "2017 Settlement Agreement"). (See Note 3 for details related to the resulting regulatory asset and allowed recovery set forth in the 2017 Settlement Agreement.) 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. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

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 coal transportation contract that runs through 2019, with the ability to extend the contract annually through 2024.

Navajo Plant — 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 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 co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that will allow for decommissioning activities to begin after the plant ceases operations in December 2019. Various stakeholders, including regulators, tribal representatives, the plant's coal supplier and DOI have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. Although we cannot predict whether any alternate plans will be found that would be acceptable to all of the stakeholders and feasible to implement, we believe it is probable that the current owners of the Navajo Plant will cease plant operations in 2019.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant (see Note 3 for details related to the resulting regulatory asset) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

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

Palo Verde Leases — In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. 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 exercise 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 participant owners of Palo Verde are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The fuel cycle for Palo Verde is comprised of the following stages:
•mining and milling of uranium ore to produce uranium concentrates;
•conversion of uranium concentrates to uranium hexafluoride;
•enrichment of uranium hexafluoride;
•fabrication of fuel assemblies;
•utilization of fuel assemblies in reactors; and
•storage and disposal of spent nuclear fuel.

The Palo Verde participants have contracted for 100% of Palo Verde's requirements for uranium concentrates through 2025 and 15% through 2028. In 2018, Palo Verde executed five uranium contracts covering the time period from 2019 to 2025.

Table of Contents

The participants have contracted for 100% of Palo Verde's requirements for conversion services through 2025, and 40% through 2030. A long-term contract for conversion services was executed in 2018 covering years 2019 to 2030.

The participants have contracted for 100% of Palo Verde's requirements for enrichment services through 2021, 90% of enrichment services for 2022, and 80% for 2023 through 2026. In 2018, four enrichment contracts were executed to bring the requirements coverage to these levels.

The participants have contracted for 100% of Palo Verde's requirements for fuel fabrication through 2027. In 2018, a fabrication contract was executed with a new fabrication supplier for Unit 2, and the existing fabrication contract was renegotiated for Units 1 and 3.

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 the 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 Palo Verde participants, filed a lawsuit against the DOE in the United States Court of Federal Claims ("Court of Federal Claims") for damages incurred due to the 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 in the Court of Federal Claims. This lawsuit sought to recover damages incurred due to the DOE's breach of the Standard Contract for failing to accept Palo 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 NWPA. On August 18, 2014, APS and the DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by the 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 reported net income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which has been extended to December 31, 2019.

APS has submitted and received payment for four claims pursuant to the terms of the August 18, 2014 settlement agreement, for four separate time periods during July 1, 2011 through June 30, 2018. The DOE has paid $74.2 million for these claims (APS’s share is $21.6 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. APS's next claim pursuant to the terms of the August 18, 2014 settlement agreement was submitted to the DOE on October 31, 2018 in the amount of $10.2 million (APS's share is $3 million). This claim is pending DOE review.

The One-Mill Fee — In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged the DOE’s 2010 determination of the adequacy of the one tenth of a cent

Table of Contents

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 the 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 the 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 the 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 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 and Continued Storage — 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").

Table of Contents

The D.C. Circuit found that the agency's Waste Confidence Decision update constituted a major federal action, which, consistent with 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 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. Renamed as the Continued Storage Rule, the NRC's decision 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 final Continued Storage Rule was subject to continuing legal challenges before the NRC and the Court of Appeals. In June 2016, the D.C. Circuit issued its final decision, rejecting all remaining legal challenges to the Continued Storage Rule. On August 8, 2016, the D.C. Circuit denied a petition for rehearing.

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 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 Generating Station — Nuclear Insurance" in Note 10 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

Table of Contents

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 two oil-only power plants: Fairview, located in the town of Douglas, Arizona and Yucca GT-4 in Yuma, AZ. 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 five 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 by truck directly to the power plants.

Ocotillo was originally 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. (See Note 3 for rate recovery as part of the ACC final written Opinion and Order issued reflecting its decision in APS's general retail rate case (the "2017 Rate Case Decision")). On September 9, 2016, Maricopa County issued a final permit decision that authorizes construction of the Ocotillo modernization project and construction began in early 2017 with completion targeted by the middle of 2019.

Solar Facilities

APS developed utility scale solar resources through the 170 MW ACC-approved AZ Sun Program, investing approximately $675 million in this program. These facilities are owned by APS and are located in multiple locations throughout Arizona. In addition to the AZ Sun Program, APS developed the 40 MW Red Rock Solar Plant, which it owns and operates. Two of our large customers purchase renewable energy credits from APS that are equivalent to the amount of renewable energy that Red Rock is projected to generate.

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 systems 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, was 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. The pilot program is now complete, and as part of the 2017 Rate Case Decision, the participants have been transferred to the Solar Partner Program described below. 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 an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system

interoperability, and was in operation by the end of 2016. The costs for this program have been included in APS's rate base as part of the 2017 Rate Case Decision.
In the 2017 Rate Case Decision, the ACC also approved the "APS Solar Communities" program. APS Solar Communities is a three-year program authorizing APS to spend $10 million - $15 million in capital costs each year to install utility-owned distributed generation systems on low to moderate income residential homes, buildings of non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES.

Energy Storage

APS deploys a number of advanced technologies on its system, including energy storage. Storage can provide capacity, improve power quality, be utilized for system regulation, integrate renewable generation, and can be used to defer certain traditional infrastructure investments. Battery storage can also aid in integrating higher levels of renewables by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale battery storage projects to evaluate the potential benefits for customers and further our understanding of how storage works with other advanced technologies and the grid. We are preparing for additional battery storage in the future.

In early 2018, APS entered into a 15-year power purchase agreement for a 65 MW solar facility that charges a 50 MW solar-fueled battery. Service under this agreement is scheduled to begin in 2021. APS issued a request for proposal for approximately 106 MW of battery storage to be located at up to five of its AZ Sun sites. Based upon our evaluation of the RFP responses, APS has decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. In February 2019, we contracted for the 141 MW and anticipate such facilities could be in service by mid-2020. Additionally, in February 2019, APS signed two 20-year power purchase agreements for energy storage totaling 150 MW. Service under these agreements are scheduled to begin in 2021. We plan to install at least an additional 660 MW of APS-owned solar plus battery storage and stand-alone battery storage systems by the summer of 2025, with the first 260 MW being procured in 2019 (60 MW on additional AZ Sun sites and 100 MW of solar plus 100 MW of battery storage).

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. In addition, APS has also entered into several power purchase agreements for energy storage. (See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Energy Storage" above for details of our energy storage power purchase agreements.)

Table of Contents

Purchased Power Capacity — APS's purchased power capacity under long-term contracts as of December 31, 2018 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 February 2021	480
Tolling Agreement	Summer seasons through October 2019	560
Demand Response Agreement (c)	Summer seasons through 2024	25
Tolling Agreement	Summer seasons from Summer 2020 through Summer 2025	565
Tolling Agreement	June 1 through September 30, 2020-2026	570
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 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."

In February 2019, APS entered into a power purchase agreement for 463 MW of summer seasonal capacity from May to October annually from 2021 through 2027.

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 2018 peak one-hour demand on its electric system was recorded on July 24, 2018 at 7,320 MW, compared to the 2017 peak of 7,363 MW recorded on June 20, 2017. APS's reserve margin at the time of the 2018 peak demand, calculated using system load serving capacity, was 18%. For 2019, due to expiring purchase contracts, APS is procuring market resources to maintain its minimum 15% planning reserve criteria.

Future Resources and Resource Plan

APS filed its preliminary 2017 Integrated Resource Plan ("IRP") on March 1, 2016 and an updated preliminary 2017 IRP on September 30, 2016. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS is required to file a Preliminary IRP by April 1, 2019 and its final IRP by April 1, 2020.

See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities" above for information regarding future plans for the Cholla Plant, Four Corners Plant, Navajo Plant and Ocotillo Plant. See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Purchased Power Contracts" above for information regarding future plans for purchased power contracts.

Table of Contents

Energy Imbalance Market

In 2015, APS and the CAISO, the operator for the majority of California's transmission grid, signed an agreement for APS to begin participation in the Energy Imbalance Market (“EIM”). APS's participation in the EIM began on October 1, 2016. The EIM allows for rebalancing supply and demand in 15-minute blocks, with dispatching every five minutes before the energy is needed, instead of the traditional one hour blocks. APS continues to expect that its participation in EIM will lower its fuel costs, improve visibility and situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS’s renewable resources.

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 9% of retail electric sales in 2019 and increases annually until it reaches 15% in 2025. In APS’s 2009 general retail rate case settlement agreement (the “2009 Settlement Agreement”), APS committed to use its best efforts 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 in 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 9% in 2019. On June 29, 2018, APS filed its 2019 RES Implementation Plan and requested a permanent waiver of the residential distributed energy requirement for 2019. The following table summarizes the RES requirement standard (not including the additional commitment required by the 2009 Settlement Agreement) and its timing:

	2019	2020	2025
RES as a % of retail electric sales	9%	10%	15%
Percent of RES to be supplied from distributed energy resources	30%	30%	30%

On April 21, 2015, the RES rules were amended to require utilities to report on all eligible renewable resources in their service territory, irrespective of whether the utility owns renewable energy credits associated with such renewable energy. The rules allow the ACC to consider such information in determining whether APS has satisfied the requirements of the RES. See "Clean Resource Energy Standard and Tariff" in Note 3 for information regarding an additional renewable energy standards proposal.

Table of Contents

Renewable Energy Portfolio. To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1,806 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1,717 MW are currently in operation and 89 MW are under contract for development or are under construction. Renewable resources in operation include 238 MW of facilities owned by APS, 629 MW of long-term purchased power agreements, and an estimated 817 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. See "Energy Sources and Resource Planning - Generation Facilities - Solar Facilities" above for information regarding APS-owned solar facilities.

The following table summarizes APS's renewable energy sources currently in operation and under development as of December 31, 2018. 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.

Table of Contents

	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**	
Red Rock	**Red Rock, AZ**	**2016**		**40**	
Distributed Energy:					
APS Owned (a)	**AZ**	**Various**		**24**	
Total APS Owned				**238**	**—**
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**	
Solar + Energy Storage:					
Sun Streams	**Arlington, AZ**	**2021**	**15**		**50**
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**	**50**
Distributed Energy					
Solar (b)					
Third-party Owned	**AZ**	**Various**		**817**	**39**
Agreement 1	**Bagdad, AZ**	**2011**	**25**	**15**	

Agreement 2	**AZ**	**2011-2012**	**20-21**	**18**	
Total Distributed Energy				**850**	**39**
Total Renewable Portfolio				**1,717**	**89**

16

Table of Contents

(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.

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 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).

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. (See Note 3 for information regarding ACC's regulation of APS's retail electric rates.)

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 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.

On November 17, 2018, the ACC voted 5-0 to again re-examine retail competition. A Special Open Meeting Workshop was held on December 3, 2018. No substantive action was taken, but interested parties were asked to submit written comments and respond to a list of questions from ACC Staff. Those comments and responses are still being submitted. The ACC is planning at least one more workshop on the issue in 2019. APS cannot predict whether these efforts will result in any changes.

Table of Contents

Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS's transmission rates.) During 2018, approximately 4.7% 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.

Subpoena from Arizona Corporation Commissioner Robert Burns

On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively, to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC Staff. As part of this docket, Commissioner Burns set March

24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Commissioner Burns filed suit against APS and Pinnacle West in the Superior Court of Arizona for Maricopa County in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Commissioner Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel.

On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns' amended complaint. On March 6, 2018, Commissioner Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Commissioner Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS's 2017 rate case. Commissioner Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed.

Table of Contents

Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants’ motions to dismiss and entered final judgment on January 18, 2019. On February 13, 2019, Commissioner Burns filed a notice of appeal. APS and Pinnacle West cannot predict the outcome of this matter.

Environmental Matters

Climate Change

Legislative Initiatives. There have been no recent successful attempts by Congress to pass legislation that would regulate greenhouse gas ("GHG") emissions, and it is unclear at this time whether the 116th 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 written and 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 at this time, 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 carbon pollution standards for EGUs, the "Clean Power Plan". On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan and proposed replacement regulations on August 21, 2018. In addition, judicial challenges to the Clean Power Plan are pending before the D.C. Circuit, though that litigation is currently in abeyance while EPA develops regulatory action to potentially repeal and replace that regulation.

EPA's pending proposal to regulate carbon emissions from EGUs replaces the Clean Power Plan with standards that are based entirely upon measures that can be implemented to improve the heat rate of steam-electric power plants, specifically coal-fired EGUs. In contrast with the Clean Power Plan, EPA's proposed "Affordable Clean Energy Rule" would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. In addition, to address the NSR implications of power plant upgrades potentially necessary to achieve compliance with the proposed Affordable Clean Energy Rule standards, EPA also proposed to revise EPA's NSR regulations to more readily authorize the implementation of EGU efficiency upgrades.

We cannot predict the outcome of EPA's regulatory actions related to the August 2015 carbon pollution standards for EGU's, including any actions related to EPA's repeal proposal for the Clean Power Plan or additional rulemaking actions to approve the EPA's recently proposed Affordable Clean Energy Rule. In addition, we cannot predict whether the D.C. Circuit Court will continue to hold the litigation challenging the original Clean Power Plan in abeyance in light of EPA's repeal proposal, which is still pending.

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.
APS prepares an annual inventory of GHG emissions from its operations. For APS's operations involving fossil-fuel electricity generation and electricity transmission and distribution, APS's annual GHG inventory is reported to EPA under the EPA GHG Reporting Program. APS also voluntarily tracks and reports the full-scope of the Company's GHG emissions arising from all APS operations. In addition to GHG emissions from generation and transmission and distribution operations, this data includes all other GHG emissions arising from ancillary Company operations, such as vehicle use, employee travel, portable generators and facility energy usage. This data is then 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.

Cholla. APS believed that EPA’s original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of selective catalytic reduction ("SCR") controls, was unsupported and that EPA had no basis for disapproving Arizona’s State Implementation Plan ("SIP") and promulgating a Federal Implementation Plan ("FIP") that was inconsistent with the state’s considered BART determinations under the regional haze program. In September 2014, APS met with EPA to propose a compromise BART strategy, whereby 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 BART requirements for oxides of nitrogen ("NOx") imposed through EPA's BART FIP. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

Table of Contents

Four Corners. Based on EPA's final standards, APS's 63% share of the cost of required BART controls for Four Corners Units 4 and 5 is approximately $400 million, the majority of which has already been incurred. (See Note 3 for information regarding the related rate recovery.) 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. 4CA purchased the El Paso interest on July 6, 2016. NTEC purchased the interest from 4CA on July 3, 2018. (See "Four Corners Coal Supply Agreement - 4CA Matter" in Note 10 for a discussion of the NTEC purchase.) The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase 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; however, given the future plans for the Navajo Plant, we do not expect to incur these costs. See "Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Navajo Generating Station" above and "Navajo Plant" in Note 3 for information regarding future plans for the Navajo Plant.

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 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. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments, and are the subject of recent regulatory and judicial activities described below.

On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation ("WIIN") Act into law, which contains a number of provisions requiring EPA to modify the self-implementing provisions of the Agency's current CCR rules under Subtitle D. Such modifications include new EPA authority to directly enforce the CCR rules through the use of administrative orders and providing states, like Arizona, where the Cholla facility is located, the option of developing CCR disposal unit permitting programs, subject to EPA approval. For facilities in states that do not develop state-specific permitting programs, EPA is required to develop a federal permit program, pending the availability of congressional appropriations. By contrast, for facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation, where the Navajo Plant and Four Corners facilities are located, EPA is required to develop a federal permit program regardless of appropriated funds.

ADEQ has initiated a process to evaluate how to develop a state CCR permitting program that would cover EGUs, including Cholla. While APS has been working with ADEQ on the development of this program, we are unable to predict when Arizona will be able to finalize and secure EPA approval for a state-specific CCR permitting program. With respect to the Navajo Nation, APS has sought clarification as to when and how EPA would be initiating permit proceedings for facilities on the reservation, including Four Corners. We are unable to predict at this time when EPA will be issuing CCR management permits for the facilities on the Navajo Nation. At this time, it remains unclear how the CCR provisions of the WIIN Act will affect APS and its management of CCR.

Based upon utility industry petitions for EPA to reconsider the RCRA Subtitle D regulations for CCR, which were premised in part on the CCR provisions of the 2016 WIIN Act, on September 13, 2017, EPA agreed to evaluate whether to revise these federal CCR regulations. On July 17, 2018, EPA finalized a revision to its RCRA Subtitle D regulations for CCR, the "Phase I, Part I" revision to its CCR regulations, deferring for future action a number of other proposed changes contemplated in a March 1, 2018 proposal. For the final rule issued on July 17, 2018, EPA established nationwide health-based standards for certain constituents of CCR subject to groundwater corrective action, and delayed the closure deadlines for certain unlined CCR surface impoundments by 18 months (for example, those disposal units required to undergo forced closure). These changes to the federal regulations governing CCR disposal are unlikely to have a material impact on APS. As for those aspects of the March 2018 rulemaking proposal for which EPA has yet to take final action, it remains unclear which specific provisions of the federal CCR rules will ultimately be modified, how they will be modified, or when such modification will occur.

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA’s CCR regulations, EPA is required to complete a rulemaking proceeding in the near future concerning whether or not boron must be included on the list of groundwater constituents that might trigger corrective action under EPA’s CCR rules. Simultaneously with the issuance of EPA's proposed modifications to the federal CCR rules in response to industry petitions, on March 1, 2018, EPA issued a proposed rule seeking comment as to whether or not boron should be included on this list. EPA is not required to take final action approving the inclusion of boron. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time APS cannot predict the eventual results of this rulemaking proceeding concerning boron.

On August 21, 2018, the D.C. Circuit Court issued its decision on the merits in this litigation. The Court upheld the legality of EPA’s CCR regulations, though it vacated and remanded back to EPA a number of specific provisions, which are to be corrected in accordance with the Court’s order. Among the issues affecting APS’s management of CCR, the D.C. Circuit’s decision vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, even where those unlined impoundments have not otherwise violated a regulatory location restriction or groundwater protection standard (i.e., otherwise triggering forced closure). At this time, it remains unclear how this D.C. Circuit Court decision will affect APS’s operations or financial results, as EPA has yet to take regulatory action on remand to revise its 2015 CCR regulations consistent with the Court’s order.

Based on this decision, on December 17, 2018, certain environmental groups filed an emergency motion with the D.C. Circuit to either stay or summarily vacate EPA's July 17, 2018 final rule extending the closure-initiation deadline for certain unlined CCR surface impoundments until October 2020. In response, EPA filed a motion to remand but not vacate that deadline extension regulation. We cannot predict the outcome of the D.C. Circuit's consideration of these dueling motions, and whether or how such a ruling would affect APS's operations or financial results.

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 $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $20 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. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. By October 17, 2017, electric utility companies that own or operate CCR disposal units, such as APS, must have collected sufficient groundwater sampling data to initiate a detection monitoring program. To the extent that certain threshold constituents are identified through this initial detection monitoring at levels above the CCR rule's standards, the rule required the initiation of an assessment monitoring program by April 15, 2018.

APS recently completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, all such units must cease operating and initiate closure by October of 2020. APS currently estimates that the additional incremental costs to complete this corrective action and closure work, along with the costs to develop replacement CCR disposal capacity, could be approximately $5 million for both Cholla and Four Corners. APS initiated an assessment of corrective measures on January 14, 2019, and anticipates completing this assessment during the summer of 2019. During this assessment, APS will gather additional groundwater data, solicit input from the public, host public hearings, and select remedies. As such, this $5 million cost estimate may change based upon APS's performance of the CCR rule's corrective action assessment process. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe any potential change to the cost estimate would have a material impact on our financial position, results of operations or cash flows.

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.

On August 11, 2017, EPA announced that it would be initiating rulemaking proceedings to potentially revise the September 2015 effluent limitation guidelines. On September 18, 2017, EPA finalized a regulation postponing the earliest date on which compliance with the effluent limitation guidelines for these waste-streams would be required from November 1, 2018 until November 1, 2020. Until EPA issues a proposal describing how it intends to change the effluent limitation guidelines for bottom ash transport water and flue gas desulfurization wastewater, it is unclear how EPA's reconsideration process will affect how the Four Corners plant manages these waste-streams. We expect that compliance with these limitations will be required in connection with National Pollution Discharge Elimination System ("NPDES") discharge permit renewals. APS anticipates that, in connection with EPA's current reconsideration of the NPDES permit for Four Corners (see "Four Corners National Pollutant Discharge Elimination System Permit" below), EPA will propose a compliance deadline for the effluent limitation guidelines governing bottom ash transport water during March of 2019. Until EPA proposes a new NPDES permit reissuance for Four Corners, it is unclear what date EPA will assign as a compliance deadline for Four Corners. 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 NOx and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA was expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. While EPA took action designating attainment and unclassifiable areas on November 6, 2017, the Agency's final action designating non-attainment areas was not issued until April 30, 2018. At that time, EPA designated the geographic areas containing Yuma and Phoenix, Arizona as in non-attainment with the 2015 70 ppb ozone NAAQS. The vast majority of APS's natural gas-fired EGUs are located in these jurisdictions. Areas of Arizona and the Navajo Nation where the remainder of APS's fossil-fuel fired EGU fleet is located were designated as in attainment. We anticipate that revisions to the SIPs and FIPs implementing required controls to achieve the new 70 ppb standard will 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.

Superfund-Related Matters. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA" or "Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible ("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 ("RI/FS") for OU3. Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS, APS anticipates finalizing the RI/FS in the summer or fall of 2019. 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 facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation, but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. In addition, APS and certain other parties not named in the remaining RID service provider lawsuit may be brought into the litigation via third-party complaints filed by the current direct defendants. 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.

Federal Agency Environmental Lawsuit Related to Four Corners

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both ESA and NEPA in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. Oral arguments in this appeal will be heard in March 2019. We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

On July 16, 2018, several environmental groups filed a petition for review before the EPA Environmental Appeals Board ("EAB") concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA's 2015 revised effluent limitation guidelines for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018 to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. EPA indicated that it anticipates proposing a replacement NPDES permit by March 2019 and, depending on the extent of public comments concerning that proposal, taking final action on a new NPDES permit by June 2019. At this time, we cannot predict the outcome of EPA's reconsideration of the NPDES permit and whether reconsideration will have a material impact on our 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 rights of way 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 operating needs. The Four Corners region, in which Four Corners is located, has historically experienced drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. However, during the past 12 months the region has received snowfall and precipitation sufficient to recover the Navajo Reservoir to an optimum operating level, reducing the probability of shortage in future years. Although the watershed and reservoirs are in a good condition at this time, APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future drought conditions that could have an impact on operations of its plants.

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 adjudication. 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, including a number of gas-fired power plants located within Maricopa and Pinal Counties. In November 1999,

Table of Contents

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.

At this time, the lower court proceedings in the Gila River adjudication are in the process of determining the specific hydro-geologic testing protocols for determining which groundwater wells located outside of the subflow zone of the Gila River should be subject to the adjudication court's jurisdiction. A hearing to determine this jurisdictional test question was held in March of 2018 in front of a special master, and a draft decision based on the evidence heard during that hearing was issued on May 17, 2018. The decision of the special master, which was finalized on November 14, 2018, but which is subject to further review by the trial court judge, accepts the proposed hydro-geologic testing protocols supported by APS and other industrial users of groundwater. Upon a final decision by the trial court judge in this matter, further proceedings thereafter will be dedicated to determining the specific hydro-geologic testing protocols for subflow depletion determinations. The determinations made in this final stage of the proceedings will ultimately govern the adjudication of rights for parties, such as APS, that rely on groundwater extraction to support their industrial operations. At this time, APS cannot predict the outcome of these proceedings.

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. On December 20, 2018, the court issued a case management order governing future proceedings in the adjudication, whereby discovery is currently scheduled to close in December 2019 and a trial will be held in June 2020.

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

BUSINESS OF OTHER SUBSIDIARIES

Bright Canyon Energy

On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCE's focus is 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.

On March 29, 2016, TransCanyon entered into a strategic alliance agreement with Pacific Gas and Electric Company ("PG&E") to jointly pursue competitive transmission opportunities solicited by the CAISO, the operator for the majority of California's transmission grid. TransCanyon and PG&E intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

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, 2018, El Dorado had total assets of approximately $8 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.

4CA

As of December 31, 2018, 4CA had total assets of approximately $72 million, primarily consisting of a note receivable from NTEC. See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generating Facilities - Coal-Fueled Generating Facilities - Four Corners" above for information regarding 4CA and the note receivable from NTEC.

OTHER INFORMATION

Subpoenas

Pinnacle West has received grand jury subpoenas issued in connection with an investigation by the office of the United States Attorney for the District of Arizona. The subpoenas seek information principally pertaining to the 2014 statewide election races in Arizona for Secretary of State and for positions on the ACC. The subpoenas request records involving certain Pinnacle West officers and employees, including the Company’s Chief Executive Officer, as well as communications between Pinnacle West personnel and a former ACC Commissioner. Pinnacle West is cooperating fully with the United States Attorney’s office in this matter.

Other Information

Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. BCE and 4CA are incorporated in Delaware. Additional information for each of these companies is provided below:

	Principal Executive Office	Year of	Approximate

	Address	Incorporation	Number of Employees at December 31, 2018
Pinnacle West	400 North Fifth Street Phoenix, AZ 85004	1985	96
APS	400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999	1920	6,158
BCE	400 East Van Buren Phoenix, AZ 85004	2014	5
El Dorado	400 East Van Buren Phoenix, AZ 85004	1983	—
4CA	400 North Fifth Street Phoenix, AZ 85004	2016	—
Total			6,259

The APS number includes employees at jointly-owned generating facilities (approximately 2,526 employees) for which APS serves as the generating facility manager. Approximately 1,330 APS employees are union employees, represented by the International Brotherhood of Electrical Workers ("IBEW"). In January 2018, the Company concluded negotiations with the IBEW and approved a two-year extension of the contract set to expire on April 1, 2018. Under the extension, union members received wage increases for 2018 and 2019; there were no other changes. The current contract expires on April 1, 2020.

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. The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers, such as the Company, that file electronically with the SEC. The address of that website is www.sec.gov. 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 and 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.

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.

APS's ability to conduct its business operations and avoid fines and penalties depends upon compliance with federal, state and 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 (approximately $1.2 million dollars per day per violation) for failure to comply with mandatory electric reliability standards. APS is also required to have numerous permits, approvals and certificates from these agencies. APS believes the necessary permits, approvals and certificates have been obtained for its existing operations and that APS's business is conducted in accordance with applicable laws in all material respects. However, changes in regulations or the imposition of new or revised laws or regulations could have an adverse impact on our results of operations. We are also unable to predict the impact on our business and operating results from pending or future regulatory activities of any of these agencies.

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

The NRC has broad authority under federal law to impose safety-related, security-related and other licensing requirements for the operation of nuclear generating 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 generating facilities, including Palo Verde. 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 of conventional pollutants and greenhouse gases, water quality, discharges of wastewater and waste 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.

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. In addition, the rule may also require corrective action to address releases from CCR disposal units or the presence of CCR constituents within groundwater near CCR disposal units above certain regulatory thresholds.

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 final attainment designations for the new standards and the state 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 potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG emissions, as well as physical and operational risks related to climate effects.

Concern over climate change has led to significant legislative and regulatory efforts to limit CO_2, which is a major byproduct of the combustion of fossil fuel, and other GHG emissions. *Potential Financial Risks - Greenhouse Gas Regulation, the Clean Power Plan and Potential Litigation.* 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. EPA took action in October 2017 to repeal these regulations and in August 2018 EPA proposed the Affordable Clean Energy Rule to replace the Clean Power Plan with a new set of regulations.

Depending on the final outcome of a pending judicial review of the Clean Power Plan, along with related regulatory activity to repeal or replace these regulations, the utility industry may face alternative efforts from private parties seeking to establish alternative GHG emission limitations from power plants. Alternative GHG emission limitations may arise from litigation under either federal or state common laws or citizen suit provisions of federal environmental statutes that attempt to force federal agency rulemaking or imposing direct facility emission limitations. Such lawsuits may also seek damages from harm alleged to have resulted from power plant GHG emissions.

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.

Co-owners of our jointly owned generation facilities may have unaligned goals and positions due to the effects of legislation, regulations, economic conditions or changes in our industry, which could have a significant impact on our ability to continue operations of such facilities.

APS owns certain of our power plants jointly with other owners with varying ownership interests in such facilities. Changes in the nature of our industry and the economic viability of certain plants, including impacts resulting from types and availability of other resources, fuel costs, legislation and regulation, together with timing considerations related to expiration of leases or other agreements for such facilities, could result in unaligned positions among co-owners. Such differences in the co-owners' willingness or ability to continue their participation could ultimately lead to disagreements among the parties as to how and whether to continue operation of such plants, which could lead to eventual shut down of units or facilities and uncertainty related to the resulting cost recovery of such assets. See Note 3 for a discussion of the co-owners' plans to cease operations of the Navajo Plant and the related risks associated with APS's continued recovery of its remaining investment in the plant.

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. This is in large part due to a 2004 Arizona Court of Appeals decision that found critical components of the ACC's rules to be violative of the Arizona Constitution. The ruling also voided the operating authority of all the competitive providers previously authorized by the ACC. 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)-X program, which essentially allows up to 200 MW of cumulative load to be served via a buy-

Table of Contents

through arrangement with competitive suppliers of generation. The AG-X program was approved by the ACC as part of the 2017 Settlement Agreement.

In November 2018, the ACC voted to again re-examine retail competition. Interested parties were asked to submit written comments, which are still being submitted. In addition, proposals to enable or support retail electric competition may be made from time to time through ballot initiatives, legislative action or other forums in Arizona. The ACC held one workshop on retail competition in December 2018 and is planning at least one more workshop on the issue in 2019. We cannot predict future regulatory or legislative action that might result in increased competition.

Proposals to change policy in Arizona or other states made through ballot initiatives or referenda may increase the Company's cost of operations or impact its business plans.

In Arizona and other states, a person or organization may file a ballot initiative or referendum with the Arizona Secretary of State or other applicable state agency and, if a sufficient number of verifiable signatures are presented, the initiative or referendum may be placed on the ballot for the public to vote on the matter. Ballot initiatives and referenda may relate to any matter, including policy and regulation related to the electric industry, and may change statutes or the state constitution in ways that could impact Arizona utility customers, the Arizona economy and the Company. Some ballot initiatives and referenda are drafted in an unclear manner and their potential industry and economic impact can be subject to varied and conflicting interpretations. We may oppose certain initiatives or referenda (including those that could result in negative impacts to our customers, the state or the Company) via the electoral process, litigation, traditional legislative mechanisms, agency rulemaking or otherwise, which could result in significant costs to the Company. The passage of certain initiatives or referenda could result in laws and regulations that impact our business plans and have a material adverse impact on our financial condition, results of operations or cash flows.

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 or 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 Resources. The ACC has enacted rules regarding energy efficiency that mandate a 22% cumulative 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 LFCR is designed to address these matters.

Table of Contents

APS must also meet certain distributed energy requirements. A portion of APS's total renewable energy requirement must be met with an increasing percentage of distributed energy resources (generally, small scale renewable technologies located on customers' properties). The distributed energy requirement was 25% of the overall RES requirement of 3% in 2011 and increased to 30% of the applicable RES requirement for 2012 and subsequent years. Customer participation in distributed energy programs would result in lower demand, since customers would be meeting some of their own energy needs.

In addition to these rules and requirements, energy efficiency technologies and distributed energy resources continue to evolve, which may have similar impacts on demand for electricity. Reduced demand due to these energy efficiency requirements, distributed energy requirements and other emerging technologies, unless substantially offset through ratemaking mechanisms, could have a material adverse impact on APS's financial condition, results of operations and cash flows.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 1.7% for the year ended December 31, 2018 compared with the prior year. For the three years 2016 through 2018, APS's retail customer growth averaged 1.6% per year. We currently project annual customer growth to be 1.5 - 2.5% for 2019 and to average in the range of 1.5 - 2.5% for 2019 through 2021 based on our assessment of improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.1% for the year ended December 31, 2018 compared with the prior year. Improving economic conditions and customer growth were offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives. For the three years 2016 through 2018, annual retail electricity sales were about flat, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.0 - 2.0% for 2019 and increase on average in the range of 1.5 - 2.5% during 2019 through 2021, 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 or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

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 renewable 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 we experience acceleration of expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives, we may be unable to reach our estimated 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. Concerns over physical security of these assets could include damage to certain of our facilities due to vandalism or other deliberate acts that could lead to outages or other adverse effects. 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.

The impact of wildfires could negatively affect APS's results of operations.

Wildfires have the potential to affect the communities that APS serves and APS's vast network of electric transmission lines and facilities. The potential likelihood of wildfires has increased due to many of the same weather impacts existing in Arizona as those that led to the recent wildfires in Northern California. While we proactively take steps to mitigate wildfire risk in the areas of our electrical assets, given APS's expansive service territory, wildfire risk is always present. APS could be held liable for damages incurred as a result of wildfires that were caused by or enhanced due to APS's negligence. The Arizona liability standard is different from that of California, which generally imposes liability for resulting damages without regard to fault. Any damage caused to our assets, loss of service to our customers or liability imposed as a result of wildfires could negatively impact APS's financial condition, results of operations or cash flows.

The inability to successfully develop or acquire generation resources to meet reliability requirements and other 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 various 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 challenges as to the appropriate generation portfolio and fuel diversification mix. In addition, APS is required by the ACC to meet certain energy resource portfolio requirements, including those related to renewables development and energy efficiency measures. The development of any generation facility is subject to many risks, including those related to financing, siting, permitting, new and evolving technology, and the construction of sufficient transmission capacity to support these facilities. 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.

In expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of fossil fuels, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the permitting and construction of fossil fuel infrastructure projects. These efforts may increase in scope and frequency depending on a number of variables, including the future course of Federal environmental regulation and the increasing financial resources devoted to these opposition activities. APS cannot predict the effect that any such opposition may have on our ability to develop and construct fossil fuel infrastructure projects in the future.

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.

Table of Contents

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

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In the regular course of our business, we handle a range of sensitive security, customer and business systems information. There appears to be an increasing level of activity, sophistication and maturity of threat actors, in particular nation state actors, that seek to exploit potential vulnerabilities in the electric utility industry and wish to disrupt the U.S. bulk power, transmission and distribution system. Our information technology systems, generation (including our Palo Verde nuclear facility), transmission and distribution facilities, and other infrastructure facilities and systems and physical assets could be targets of unauthorized access and are critical areas of cyber protection for us.

Despite implementation of security measures, our technology systems are vulnerable to disability, failures or unauthorized access. If a significant cybersecurity event or breach were to occur, we may not be able to fulfill critical business functions and we could (i) experience property damage, disruptions to our business, theft of or unauthorized access to customer, employee, financial or system operation information or other information; (ii) experience loss of revenue or incur significant costs for repair, remediation and breach notification, and increased capital and operating costs to implement increased security measures; and (iii) be subject to increased regulation, litigation and reputational damage. These types of events could also require significant management attention and resources, and 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 bulk power systems, and is continually in the process of developing updated and additional requirements with which the utility industry must comply. The NRC also has issued regulations and standards related to the protection of critical digital assets at commercial nuclear power plants. The increasing promulgation of NERC and NRC rules and standards will increase our compliance costs and our exposure to the potential risk of violations of the standards. Experiencing a cybersecurity incident could cause us to be non-compliant with applicable laws and regulations, such as those promulgated by NERC and the NRC, or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings and regulatory fines or penalties.

The risk of these system-related events and security breaches occurring continues to intensify. We have experienced, and expect to continue to experience, threats and attempted intrusions to our information technology systems and we could experience such threats and attempted intrusions to our operational control systems. To date we have not experienced a material breach or disruption to our network or information systems or our service operations. However, as such attacks continue to increase in sophistication and frequency, we may be unable to prevent all such attacks from being successful in the future.

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 is subject to a number of exclusions and may not cover the total loss or damage caused by a breach. The market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may evolve as the industry matures. In the future, adequate insurance may not be available at rates that we believe are reasonable, and the costs of responding to and recovering from a cyber incident may not be covered by insurance or recoverable in rates.

Table of Contents

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 certain APS transmission lines 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 outcomes of pending and future approvals by the applicable sovereign governing bodies with respect to renewals of these leases, easements and rights-of-way.

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

APS has an ownership interest in and operates, on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the United States. Palo Verde constitutes approximately 18% of our owned and leased generation capacity. Palo Verde is subject to environmental, health and financial risks, such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. In addition, APS may be required under federal law to pay up to $120.1 million (but not more than $17.9 million per year) of liabilities arising out of a nuclear incident occurring not only at Palo Verde, but at any other nuclear power reactor 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 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 and increase the complexity of managing APS's information technology and power system operations, 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. The implementation of new and additional technologies adds complexity to our information technology and operational technology systems, which could require additional infrastructure and resources. Widespread installation and acceptance of new technologies could also 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 traditional business model.

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 support 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 many companies in the electric utility industry, our workforce is maturing, with approximately 30% of employees eligible to retire by the end of 2020. Although we have undertaken efforts to recruit, train and develop new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability and retention of qualified personnel and the need to negotiate collective bargaining agreements with union employees. These or other employee workforce factors could negatively impact our business, financial condition or results of operations.

Table of Contents

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.

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.

Table of Contents

Investment performance, changing interest rates and other economic, social and political factors could decrease the value of our benefit plan assets and nuclear decommissioning trust funds or increase the valuation of our related obligations, resulting in significant additional funding requirements. We are also 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 our pension trust and nuclear decommissioning trusts for Palo Verde. We hold and invest substantial assets in these trusts that are designed to provide funds to pay for certain of these obligations as they arise. Declines in market values of the fixed income and equity securities held in these trusts may increase our funding requirements into the related trusts. Additionally, the valuation of liabilities related to our pension plan and other postretirement benefit plans are impacted by a discount rate, which is the interest rate used to discount future pension and other postretirement benefit obligations. Declining interest rates decrease the discount rate, increase the valuation of the plan liabilities and may result in increases in pension and other postretirement benefit costs, cash contributions, regulatory assets, and charges to OCI. Changes in demographics, including increased 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 and related regulations. 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 currently estimated 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. While most of the Patient Protection and Affordable Care Act provisions have been implemented, changes to or repeal of that Act and pending or future federal or state legislative or regulatory activity or court proceedings could increase costs of providing medical insurance for our employees and retirees. Any potential changes and resulting cost impacts 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.

Table of Contents

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

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

The market price of our common stock may be volatile.

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

- variations in our quarterly operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance, including financial estimates by securities analysts and investors;
- developments generally affecting industries in which we operate;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- announcements by third parties of significant claims or proceedings against us;
- favorable or adverse regulatory or legislative developments;
- our dividend policy;
- future sales by the Company of equity or equity-linked securities; and
- general domestic and international economic conditions.

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

41

Table of Contents

- 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 2018 fiscal year and that remain unresolved.

Table of Contents

ITEM 2. PROPERTIES

Generation Facilities

APS

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 1,3	2		Coal	Base Load	387
Navajo (d)	3	14 %	Coal	Base Load	315
Ocotillo (e)	—		Gas	Peaking	—
Total Steam					1,672
Combined Cycle:					
Redhawk	2		Gas	Load Following	984
West Phoenix	5		Gas	Load Following	887
Total Combined Cycle					1,871
Combustion Turbine:					
Ocotillo (e)	2		Gas	Peaking	110
Saguaro	3		Gas	Peaking	189
Douglas/Fairview	1		Oil	Peaking	16
Sundance	10		Gas	Peaking	420
West Phoenix	2		Gas	Peaking	110
Yucca 1, 2, 3	3		Gas	Peaking	93
Yucca 4	1		Oil	Peaking	54
Yucca 5, 6	2		Gas	Peaking	96
Total Combustion Turbine					1,088
Solar:					
Cotton Center (f)	1		Solar	As Available	17
Hyder I (f)	1		Solar	As Available	16
Paloma (f)	1		Solar	As Available	17
Chino Valley	1		Solar	As Available	19
Gila Bend (f)	1		Solar	As Available	32
Hyder II (f)	1		Solar	As Available	14
Foothills (f)	1		Solar	As Available	35
Luke AFB	1		Solar	As Available	10
Desert Star (f)	1		Solar	As Available	10
Red Rock	1		Solar	As Available	40
APS Owned Distributed Energy			Solar	As Available	24
Multiple facilities			Solar	As Available	4
Total Solar					238
Total Capacity					6,015

Table of Contents

(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 NTEC (7%). The plant is operated by APS.

(d) The other participants are Salt River Project (42.9%), Nevada Power Company (11.3%), the United States Government (24.3%) and Tucson Electric Power Company (7.5%). The plant is operated by Salt River Project. In July 2016, Salt River Project purchased Los Angeles Department of Water & Power's share in this plant (21.2%).

(e) Ocotillo Steam Units 1 and 2 were retired on January 10, 2019. Units 3 through 7 are expected to go into service by the middle of 2019 and will increase generation capacity by 510 MW.

(f) APS is under contract to add battery storage at these AZ Sun sites and anticipates such storage facilities could be in service by mid-2020. (See "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Energy Storage" above for details related to these and other energy storage agreements.)

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.

4CA

4CA, a wholly-owned subsidiary of Pinnacle West, purchased El Paso's 7% interest in Units 4 and 5 of Four Corners on July 6, 2016 and subsequently sold the interest to NTEC on July 3, 2018. See "Areas of Business Focus - Operational Performance, Reliability and Recent Developments - Four Corners - Asset Purchase Agreement and Coal Supply Matters" in Item 7 for additional information about 4CA's interest in Four Corners.

Transmission and Distribution Facilities

***Current Facilities*.** APS's transmission facilities consist of approximately 6,192 pole miles of overhead lines and approximately 49 miles of underground lines, 5,969 miles of which are located in Arizona. APS's distribution facilities consist of approximately 11,194 miles of overhead lines and approximately 21,854 miles of underground primary cable, all of which are located in Arizona. APS distribution facilities reflect an actual net gain of 357 miles in 2018. APS shares ownership of some of its transmission facilities with other companies.

Table of Contents

The following table shows APS's jointly-owned interests in those transmission facilities recorded on the Consolidated Balance Sheets at December 31, 2018:

	Percent Owned (Weighted-Average)	
Morgan — Pinnacle Peak System	64.6	%
Palo Verde — Rudd 500kV System	50.0	%
Round Valley System	50.0	%
ANPP 500kV System	33.5	%
Navajo Southern System	26.7	%
Four Corners Switchyards	63.1	%
Palo Verde — Yuma 500kV System	19.0	%
Phoenix — Mead System	17.1	%
Palo Verde — Morgan System	87.9	%
Hassayampa — North Gila System	80.0	%
Cholla 500kV Switchyard	85.7	%
Saguaro 500kV Switchyard	60.0	%
Kyrene - Knox System	50.0	%

Expansion. Each year APS prepares and files with the ACC a ten-year transmission plan. In APS's 2019 plan, APS projects it will develop 15 miles of new transmission lines over the next ten years. One significant project, the Palo Verde to Morgan project recently completed all phases and is a new 500kV path that spans from the Palo Verde hub around the western and northern edges of the Phoenix metropolitan area and terminates at a bulk substation in the northeast part of Phoenix. The Palo Verde to Morgan project includes Palo Verde-Delaney-Sun Valley-Morgan-Pinnacle Peak. The project consisted of four phases and the fourth phase, Morgan to Sun Valley 500kV, was energized in April of 2018. In total, the project consisted 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 have been completed and were included in previous APS transmission plans, are the Delaney to Palo Verde line and the North Gila to Hassayampa line, both of which support the transmission of renewable energy to Phoenix and California. The North Gila to Hassayampa line went into service in May 2015 and the Delaney to Palo Verde line went into service in May 2016.

Physical Security Standards. On July 14, 2015, FERC approved version 2 of the proposed Physical Security Reliability Standard CIP-014. APS completed its initial implementation in 2018. No additional significant financial or operational impacts on APS are anticipated.

NERC Critical Infrastructure Protection Reliability Standards. Since 2014, APS has been implementing a comprehensive project to ensure compliance with NERC's Critical

Infrastructure Protection Reliability Standards ("CIP"). As a result of recent revisions to the CIP standards, the final compliance date is now January 1, 2020. APS is 95% complete in its compliance implementation activities with total expenditures of $60.4 million incurred by APS as of December 31, 2018. APS anticipates an additional expenditure of approximately $0.2 million with a final completion date in September 2019.

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 co-owners of the Navajo Plant and the Navajo

Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that will allow for decommissioning activities to begin after the plant ceases operations in December 2019. Various stakeholders, including regulators, tribal representatives, the plant's coal supplier and the DOI have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. Although we cannot predict whether any alternate plans will be found that would be acceptable to all of the stakeholders and feasible to implement, we believe it is probable that the current owners of the Navajo Plant will cease plant operations in December 2019.

APS, on behalf of the Four Corners participants, negotiated amendments to the Four Corners facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. See "Areas of Business Focus - Operational Performance, Reliability and Recent Developments - Four Corners - Lease Extension" in Item 7 for additional information about the Four Corners right-of-way and lease matters.

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

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 22, 2019, current positions and principal occupations for the past five years are as follows:

Name	Age	Position	Period
Donald E. Brandt	64	Chairman of the Board and Chief Executive Officer of Pinnacle West; Chairman of the Board of APS	2009-Present
		President of APS	2013-2018
		President of Pinnacle West	2008-Present
		Chief Executive Officer of APS	2008-Present
Robert S. Bement	63	Executive Vice President and Chief Nuclear Officer, PVGS, of APS	2016-Present
		Senior Vice President, Site Operations, PVGS, of APS	2011-2016
Denise R. Danner	63	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
Donna M. Easterly	54	Vice President, Human Resources and Ethics of APS	2017-Present
		Vice President, Chief Procurement Officer of APS	2014-2017
		Director, Transmission and Distribution Construction of APS	2013-2014
		Director, Statewide Energy Delivery of APS	2010-2013
Daniel T. Froetscher	57	Executive Vice President, Operations of APS	2018-Present
		Senior Vice President, Transmission, Distribution & Customers of APS	2014-2018
		Vice President, Energy Delivery of APS	2008-2014
Jeffrey B. Guldner	53	President of APS	2018-Present
		Executive Vice President, Public Policy of Pinnacle West	2017-Present
		Executive Vice President, Public Policy of APS	2017-2018
		General Counsel of Pinnacle West and APS	2017-2018
		Senior Vice President, Public Policy of APS	2014-2017
		Senior Vice President, Customers and Regulation of APS	2012-2014
James R. Hatfield	61	Executive Vice President of Pinnacle West and APS	2012-Present
		Chief Financial Officer of Pinnacle West and APS	2008-Present
John S. Hatfield	53	Vice President, Communications of APS	2010-Present
Barbara D. Lockwood	52	Vice President, Regulation of APS	2015-Present
		General Manager, Regulatory Policy and Compliance of APS	2014-2015
		General Manager, Innovation of APS	2012-2014
Lee R. Nickloy	52	Vice President and Treasurer of Pinnacle West and APS	2010-Present
Robert E. Smith	49	Senior Vice President and General Counsel of Pinnacle West and APS	2018-Present

Table of Contents

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 under stock symbol PNW. At the close of business on February 15, 2019, Pinnacle West's common stock was held of record by approximately 17,769 shareholders.

APS's common stock is wholly-owned by Pinnacle West and is not listed for trading on any stock exchange. The sole holder of APS's common stock, Pinnacle West, is entitled to dividends when and as declared out of legally available funds. At December 31, 2018, APS did not have any outstanding preferred stock.

Table of Contents

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

The selected data presented below as of and for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 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.

	2018	2017	2016	2015	2014
	(dollars in thousands, except per share amounts)				
OPERATING RESULTS					
Operating revenues	$3,691,247	$3,565,296	$3,498,682	$3,495,443	$3,491,632
Net income	530,540	507,949	461,527	456,190	423,696
Less: Net income attributable to noncontrolling interests	19,493	19,493	19,493	18,933	26,101
Net income attributable to common shareholders	$511,047	$488,456	$442,034	$437,257	$397,595
COMMON STOCK DATA					
Book value per share – year-end	$46.59	$44.80	$43.14	$41.30	$39.50
Earnings per weighted-average common share outstanding:					
Net income attributable to common shareholders – basic	$4.56	$4.37	$3.97	$3.94	$3.59
Net income attributable to common shareholders – diluted	$4.54	$4.35	$3.95	$3.92	$3.58
Dividends declared per share	$2.87	$2.70	$2.56	$2.44	$2.33
Weighted-average common shares outstanding – basic	112,129,017	111,838,922	111,408,729	111,025,944	110,626,101
Weighted-average common shares outstanding – diluted	112,549,722	112,366,675	112,046,043	111,552,130	111,178,141
BALANCE SHEET DATA					
Total assets	$17,664,202	$17,019,082	$16,004,253	$15,028,258	$14,288,890
Liabilities and equity:					
Current liabilities	$1,648,964	$1,197,852	$1,292,946	$1,442,317	$1,559,143
Long-term debt less current maturities	4,638,232	4,789,713	4,021,785	3,462,391	3,006,573
Deferred credits and other	6,028,301	5,895,787	5,753,610	5,404,093	5,204,072
Total liabilities	12,315,497	11,883,352	11,068,341	10,308,801	9,769,788
Total equity	5,348,705	5,135,730	4,935,912	4,719,457	4,519,102
Total liabilities and equity	$17,664,202	$17,019,082	$16,004,253	$15,028,258	$14,288,890

Table of Contents

SELECTED FINANCIAL DATA
ARIZONA PUBLIC SERVICE COMPANY – CONSOLIDATED

	2018	2017	2016	2015	2014
	(dollars in thousands)				
OPERATING RESULTS					
Operating revenues	$3,688,342	$3,557,652	$3,498,090	$3,494,900	$3,490,998
Fuel and purchased power costs	1,094,020	992,744	1,082,625	1,101,298	1,179,829
Other operating expenses	1,764,554	1,640,369	1,556,980	1,556,670	1,505,644
Operating income	829,768	924,539	858,485	836,932	805,525
Other income	111,015	60,482	52,081	54,225	60,985
Interest expense — net of allowance for borrowed funds	206,211	192,051	183,090	176,109	181,830
Net income before income taxes	734,572	792,970	727,476	715,048	684,680
Income taxes	144,814	269,168	245,842	245,841	237,360
Net income	589,758	523,802	481,634	469,207	447,320
Less: Net income attributable to noncontrolling interests	19,493	19,493	19,493	18,933	26,101
Net income attributable to common shareholder	$570,265	$504,309	$462,141	$450,274	$421,219
BALANCE SHEET DATA					
Total assets	$17,565,323	$16,893,751	$15,931,175	$14,982,182	$14,190,362
Liabilities and equity:					
Total equity	$5,786,797	$5,385,869	$5,037,970	$4,814,794	$4,629,852
Long-term debt less current maturities	4,189,436	4,491,292	4,021,785	3,337,391	2,881,573
Total capitalization	9,976,233	9,877,161	9,059,755	8,152,185	7,511,425
Current liabilities	1,576,097	1,098,274	1,094,037	1,424,708	1,532,464
Deferred credits and other	6,012,993	5,918,316	5,777,383	5,405,289	5,146,473
Total liabilities and equity	$17,565,323	$16,893,751	$15,931,175	$14,982,182	$14,190,362

Table of Contents

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. Palo Verde experienced strong performance during 2018, with its three units achieving a combined year-end capacity factor of 90.2% and an all-time best collective radiation exposure dose performance in the history of Palo Verde's operation. For additional information, see "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Nuclear."

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 August 3, 2015, EPA finalized a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"), which the EPA later proposed repealing. EPA is considering a proposed replacement to the Clean Power Plan, which was published on August 21, 2018. This new proposal, the "Affordable Clean Energy Rule," is more narrow than its predecessor regulation, and is based entirely upon heat-rate improvements at steam-electric power plants. See "Business - Environmental Matters - Climate Change - Regulatory Initiatives" for additional information on the current status of EPA's carbon pollution standards for EGUs. APS continually analyzes its long-range capital management plans to assess the potential effects of such proposals, 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.

Cholla

On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla 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, which was later addressed in the 2017 Settlement Agreement. (See Note 3 for details related to the resulting cost recovery.) 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. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017. For additional information, see "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Coal-Fueled Generating Facilities - Cholla."

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 prior general 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. This decision was appealed and, on September 26, 2017, the Arizona Court of Appeals affirmed the ACC's decision on the Four Corners rate adjustment.

Concurrently with the closing of the SCE transaction described above, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that served 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. 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 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 agreed to assume the 7% shortfall obligation. (See Note 10 for a discussion of a settlement related to the 2016 Coal Supply Agreement and an advance purchase of coal inventory made under the agreement.) 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. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

NTEC had the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. Concurrent with the settlement of the 2016 Coal Supply Agreement matter described in Note 10, NTEC and 4CA agreed to allow for the purchase by NTEC of the 7% interest, consistent with the option. On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. Completion of the sale was subject to the receipt of approval by FERC, which was received on July 2, 2018, and the sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA’s book value, approximately $70 million, and will pay 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

Table of Contents

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA, as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA’s power sales. Such payments are due to 4CA at the end of each calendar year. A $10 million payment was due to 4CA at December 31, 2017, which NTEC satisfied by directing to 4CA a prepayment from APS of a portion of a future mine reclamation obligation. The balance of the amount due under this formula at December 31, 2018 for calendar year 2017 was approximately $20 million, which was paid to 4CA on December 14, 2018. The balance of the amount under this formula for calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which is due to 4CA at December 31, 2019.

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 of decision on July 17, 2015 justifying the agency action extending the life of the plant and the adjacent mine.

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the ESA and NEPA in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. Oral argument for this appeal has been scheduled for March 2019.

We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

Wastewater Permit. On July 16, 2018, several environmental groups filed a petition for review before the EPA EAB concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA's 2015 revised effluent limitation guidelines for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018 to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. EPA indicated that it anticipates proposing a replacement NPDES permit by March 2019 and, depending on the extent of public comments concerning that proposal, taking final action on a new NPDES permit by June 2019. At this time, we cannot predict the outcome of EPA's reconsideration of the NPDES permit and whether reconsideration will have a material impact on our financial position, results of operations or cash flows.

Table of Contents

For additional information, see "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Four Corners."

Navajo Plant

The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that will allow for decommissioning activities to begin after the plant ceases operations in December 2019. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and DOI have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. Although we cannot predict whether any alternate plans will be found that would be acceptable to all of the stakeholders and feasible to implement, we believe it is probable that the current owners of the Navajo Plant will cease plant operations in December 2019.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant (see Note 3 for details related to the resulting regulatory asset) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and may be material.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

For additional information, see "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Navajo Plant."

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo was originally 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 the middle of

2019. (See Note 3 for details of the rate recovery in our 2017 Rate Case Decision.) For additional information, see "Business of Arizona Public Service Company - Energy Sources and Resource Planning - Generation Facilities - Coal-Fueled Generating Facilities - Natural Gas and Oil-Fueled Generating Facilities."

Transmission and Delivery. APS continues to work closely with customers, stakeholders, and regulators to identify and plan for transmission needs that support new customers, 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, 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 manage their energy usage, minimize system outage durations and frequency, enable customer choice for new customer sited technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions.

Energy Imbalance Market. In 2015, APS and the CAISO, the operator for the majority of California's transmission grid, signed an agreement for APS to begin participation in EIM. APS's participation in the EIM began on October 1, 2016. The EIM allows for rebalancing supply and demand in 15-minute blocks with dispatching every five minutes before the energy is needed, instead of the traditional one hour blocks. APS continues to expect that its participation in EIM will lower its fuel costs, improve visibility and situational awareness for system operations in the Western Interconnection power grid, and improve integration of APS's renewable resources.

Energy Storage. APS deploys a number of advanced technologies on its system, including energy storage. Storage can provide capacity, improve power quality, be utilized for system regulation, integrate renewable generation, and can be used to defer certain traditional infrastructure investments. Battery storage can also aid in integrating higher levels of renewables by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale battery storage projects to evaluate the potential benefits for customers and further our understanding of how storage works with other advanced technologies and the grid. We are preparing for additional battery storage in the future.

In early 2018, APS entered into a 15-year power purchase agreement for a 65 MW solar facility that charges a 50 MW solar-fueled battery. Service under this agreement is scheduled to begin in 2021. APS issued a request for proposal for approximately 106 MW of battery storage to be located at up to five of its AZ Sun sites. Based upon our evaluation of the RFP responses, APS has decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. In February 2019, we contracted for the 141 MW and anticipate such facilities could be in service by mid-2020. Additionally, in February 2019, APS signed two 20-year power purchase agreements for energy storage totaling 150 MW. Service under these agreements are scheduled to begin in 2021. We plan to install at least an additional 660 MW of APS-owned solar plus battery storage and stand-alone battery storage systems by the summer of 2025, with the first 260 MW being procured in 2019 (60 MW on additional AZ Sun sites and 100 MW of solar plus 100 MW of battery storage).

Regulatory Matters

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. See Note 3 for information on APS's FERC rates.

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates of $165.9 million. This amount excluded amounts that were then collected on customer bills through adjustor mechanisms. The application requested that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have had an incremental effect on average customer bills. The average annual customer bill impact of APS's request was an increase of 5.74% (the average annual bill impact for a typical APS residential customer was 7.96%). See Note 3 for details regarding the principal provisions of APS's application.

On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations signed the 2017 Settlement Agreement and filed it with the ACC. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as 4.54%). (See Note 3 for details of the 2017 Settlement Agreement.)

On August 15, 2017, the ACC approved (by a vote of 4-1), the 2017 Settlement Agreement without material modifications. On August 18, 2017, the ACC issued the 2017 Rate Case Decision, which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017.

On October 17, 2017, Warren Woodward (an intervener in APS's general retail rate case) filed a Notice of Appeal in the Arizona Court of Appeals, Division One. The notice raises a single issue related to the application of certain rate schedules to new APS residential customers after May 1, 2018. Mr. Woodward filed a second notice of appeal on November 13, 2017 challenging APS's $5 per month automated metering infrastructure opt-out program. Mr. Woodward's two appeals have been consolidated and APS requested and was granted intervention. Mr. Woodward filed his opening brief on March 28, 2018. The ACC and APS filed responsive briefs on June 21, 2018. The Arizona Court of Appeals issued a Memorandum Decision on December 11, 2018 affirming the ACC decisions challenged by Mr. Woodward. Mr. Woodward filed a petition for review with the Arizona Supreme Court on January 9, 2019. Review by the Arizona Supreme Court is discretionary. APS cannot predict the outcome of this consolidated appeal but does not believe it will have a material impact on our financial position, results of operations or cash flows.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the Administrative Law Judge to be a complaint filed pursuant to Arizona Revised Statute §40-246 and not a request for rehearing. Arizona Revised Statute §40-246 requires the ACC to hold a hearing regarding any complaint alleging that a public service corporation is in violation of any commission order or that the rates being charged are not just and reasonable if the complaint is signed by at least twenty-five customers of the public service corporation. The Complaint alleged that APS is "in violation of commission order" [sic]. On February 13, 2018, the complainant filed an amended Complaint alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The complainant requested that the ACC hold a hearing on the amended Complaint to determine if the average bill impact on residential customers of the rates and charges approved in the 2017 Rate Case Decision is greater than 4.54% (the average annual bill impact for a typical APS residential customer estimated by APS) and, if so, what effect the alleged greater bill impact has on APS's revenues and the overall reasonableness and justness of APS's rates and charges, in order to determine if there is sufficient evidence to warrant a full-scale rate hearing. The ACC held a hearing on this matter beginning in September 2018 and the hearing was concluded on October 1, 2018. Post-hearing briefing was concluded on December 14, 2018. APS expects a recommended opinion and order from the judge within the first quarter of 2019. APS cannot predict the outcome of this matter.

On December 24, 2018, certain ACC Commissioners filed a letter stating that because the ACC had received a substantial number of complaints that the rate increase authorized by the 2017 Rate Case Decision was much more than anticipated, they believe there is a possibility that APS is earning more than was authorized by the 2017 Rate Case Decision. Accordingly, the ACC Commissioners requested the ACC Staff to perform a rate review of APS using calendar year 2018 as a test year and file a report by May 3, 2019. The ACC Commissioners also asked the ACC Staff to evaluate APS's efforts to educate its customers regarding the new rates approved in the 2017 Rate Case Decision. On January 9, 2019, the ACC Commissioners voted to open a docket for this matter. APS does not believe that the rate review will have a material impact on our financial position, results of operations or cash flows. However, depending upon the results of the rate review, the ACC may take further actions, including potentially attempting to reopen the 2017 Rate Case Decision. APS cannot predict the outcome of this matter.

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 below and in Note 3.

SCR Cost Recovery. On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the rate adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million dollar annual revenue requirement related to the installation and operation of the SCRs. Exceptions to the Recommended Opinion and Order were filed by the parties and intervenors on December 7, 2018. The ACC has not issued a decision on this matter. APS anticipates a decision later in 2019.

Renewable Energy**.** The ACC approved the RES in 2006. The renewable energy requirement is 9% of retail electric sales in 2019 and increases annually until it reaches 15% in 2025. In APS's 2009 general retail rate case settlement agreement, APS agreed to exceed the RES standards, committing to use APS's best efforts 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 in 2015. A component of the RES targets development of distributed energy systems. For additional information, see "Business of Arizona Public Service Company-Energy Sources and Resource Planning - Current and Future Resources-Renewable Energy Standard."

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. On April 7, 2017, APS filed an amended 2017 RES Implementation Plan and updated budget request which included the revenue neutral transfer of specific revenue requirements into base rates in accordance with the 2017 Settlement Agreement. On August 15, 2017, the ACC approved the 2017 RES Implementation Plan.

On June 30, 2017, APS filed its 2018 RES Implementation Plan and proposed a budget of approximately $90 million. APS's budget request supports existing approved projects and commitments and includes the anticipated transfer of specific revenue requirements into base rates in accordance with the 2017 Settlement Agreement and also requests a permanent waiver of the residential distributed energy requirement for 2018 contained in the RES rules. APS's 2018 RES budget request is lower than the 2017 RES budget due in part to a certain portion of the RES being collected by APS in base rates rather than through the RES adjustor.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a three-year program authorizing APS to spend $10 million - $15 million in capital costs each year to install utility-owned distributed generation ("DG") systems for low to moderate income residential homes, buildings of non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES. On June 12, 2018, the ACC approved the 2018 RES Implementation Plan.

On June 29, 2018, APS filed its 2019 RES Implementation Plan and proposed a budget of approximately $89.9 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2019 contained in the RES rules. The ACC has not yet ruled on the 2019 RES Implementation Plan.

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. On January 30, 2018, ACC Commissioner Tobin proposed a plan in this proceeding which would broaden the RES to include a series of energy policies tied to clean energy sources (the "Energy Modernization Plan"). The Energy Modernization Plan includes replacing the current RES standard with a new standard called the Clean Resource Energy Standard and Tariff ("CREST"), which incorporates the proposals in the Energy Modernization Plan. A set of CREST rules for the ACC's consideration was issued by Commissioner Tobin's office on July 5, 2018. See Note 3 for more information on the RES and the Energy Modernization Plan.

Demand Side Management. In December 2009, Arizona regulators placed an increased focus on energy efficiency and other demand side management programs to encourage customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. The ACC initiated an Energy Efficiency rulemaking, with a proposed EES of 22% cumulative annual energy savings by 2020. The 22% figure represents the cumulative reduction in future energy usage through 2020 attributable to energy efficiency initiatives. This standard became effective on January 1, 2011.

On June 1, 2016, APS filed its 2017 Demand Side Management Implementation Plan ("DSM Plan"), in which APS proposed programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Plan was $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Plan that incorporated the proposed $4 million Residential Demand Response, Energy Storage and Load Management Program that was filed with the ACC on December 5, 2016 and requested that the budget for the 2017 DSM Plan be increased to $66.6 million. On August 15, 2017, the ACC approved the amended 2017 DSM Plan.

On September 1, 2017, APS filed its 2018 DSM Plan, which proposes modifications to the demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan seeks a reduced requested budget of $52.6 million and requests a waiver of the EES for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels, but kept the overall budget at $52.6 million. The ACC has not yet ruled on the APS 2018 amended DSM Plan.

On December 31, 2018, APS filed its 2019 DSM Plan, which requests a budget of $34.1 million and continues APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The ACC has not yet ruled on the APS 2019 DSM Plan. See Note 3 for more information on demand side management.

Tax Expense Adjustor Mechanism and FERC Tax Filing. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. On December 22, 2017 the Tax Cuts and Jobs Act (“Tax Act”) was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On January 8, 2018, APS filed an application with the ACC requesting that the TEAM be implemented in two steps. The first addresses the change in the marginal federal tax rate from 35% to 21% resulting from the Tax Act and, if approved, would reduce rates by $119.1 million annually through an equal cents per kWh credit. APS asked that this decrease become effective February 1, 2018. On February 22, 2018, the ACC approved the reduction of rates by $119.1 million for the remainder of 2018 through an equal cents per kWh credit applied to all but a small subset of customers who are taking service under specially-approved tariffs. The rate reduction was effective the first billing cycle in March 2018.

The impact of the TEAM, over time, is expected to be earnings neutral. However, on a quarterly basis, there is a difference between the timing and amount of the income tax benefit and the reduction in revenues refunded through the TEAM related to the lower federal income tax rate. The amount of the benefit of the lower federal income tax rate is based on quarterly pre-tax results, while the reduction in revenues from the prior year due to lower customer rates through the TEAM is based on a per kWh sales credit which follows our seasonal kWh sales pattern and is not impacted by earnings of the Company.

On August 13, 2018, APS filed a second request with the ACC to return an additional $86.5 million in tax savings to customers. This second request addresses amortization of non-depreciation related excess deferred taxes previously collected from customers. The ACC has not yet approved this request.
Additionally, as part of this second request, APS informed the ACC of its intent to file a third future request to address the amortization of depreciation related excess deferred taxes, as the Company is currently in the process of seeking IRS guidance regarding the amortization method and period applicable to these depreciation related excess deferred taxes.
The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs noted above. As discussed in Note 3, FERC issued an order on May 22, 2018 authorizing APS to provide for the cost reductions resulting from the income tax changes in its wholesale transmission rates.

See Note 3 for additional details.

Net Metering. In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of DG to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, an Administrative Law Judge issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended opinion and order by the Administrative Law Judge. After making several amendments, the ACC approved the recommended opinion and order by a 4-1 vote. As a result of the ACC’s action, effective with APS’s 2017 Rate Case Decision, the net metering tariff that governs payments for energy exported to the grid from residential rooftop solar systems was replaced by a more formula-driven approach that utilizes inputs from historical wholesale solar power until an avoided cost methodology is developed by the ACC.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a resource comparison proxy methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this resource comparison proxy method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent general retail rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to September 1, 2017, the date new rates were effective based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;
- Customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and
- Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh is included in the 2017 Settlement Agreement and became effective on September 1, 2017.

In accordance with the 2017 Rate Case Decision, APS filed its request for a second-year export energy price of 11.6 cents per kWh on May 1, 2018. This price reflects the 10% annual reduction discussed above. The new tariff became effective on October 1, 2018.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Arizona Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. As part of the 2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

Subpoena from Arizona Corporation Commissioner Robert Burns. On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively, to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns’ subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC Staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Commissioner Burns filed suit against APS and Pinnacle West in the Superior Court of Arizona for Maricopa County in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Commissioner Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel.

On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns’ amended complaint. On March 6, 2018, Commissioner Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Commissioner Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS’s 2017 rate case. Commissioner Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants’ motions to dismiss and entered final judgment on January 18, 2019. On February 13, 2019, Commissioner Burns filed a notice of appeal. APS and Pinnacle West cannot predict the outcome of this matter.

Renewable Energy Ballot Initiative. On February 20, 2018, a renewable energy advocacy organization filed with the Arizona Secretary of State a ballot initiative for an Arizona constitutional amendment requiring Arizona public service corporations to provide at least 50% of their annual retail sales of electricity from renewable sources by 2030. For purposes of the proposed amendment, eligible renewable sources would not include nuclear generating facilities. The initiative was placed on the November 2018 Arizona elections ballot. On November 6, 2018, the initiative failed to receive adequate voter support and was defeated.

Energy Modernization Plan. On January 30, 2018, ACC Commissioner Tobin proposed the Energy Modernization Plan, which consists of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the IRP process. The Energy Modernization Plan includes replacing the current RES standard with a new standard called the CREST, which incorporates the proposals in the Energy Modernization Plan. On February 22, 2018, the ACC Staff filed a Notice of Inquiry to further examine the matter. As a part of this proposal, the ACC voted in March 2018 to direct utilities to develop a comprehensive biomass generation plan to be included in each utility's RES Implementation Plan. On July 5, 2018, Commissioner Tobin's office issued a set of draft CREST rules for the ACC's consideration.

In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the Renewable Energy Standard, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics. Workshops on these energy issues are scheduled to be held throughout 2019. APS cannot predict the outcome of this matter.

Table of Contents

Integrated Resource Planning. ACC rules require utilities to develop fifteen-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS is required to file a Preliminary Resource Plan by April 1, 2019 and its final IRP by April 1, 2020.

FERC Matter. As part of APS's acquisition of SCE's interest in Four Corners 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. 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 established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed for a rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. On October 5, 2017, FERC issued an order denying APS's request for rehearing. FERC also upheld its prior determination that the agreement relating to the settlement was a jurisdictional contract and should have been filed with FERC. APS cannot predict whether or if the enforcement division will take any action. APS filed an appeal of FERC's July 1, 2016 and October 5, 2017 orders with the United States Court of Appeals for the Ninth Circuit on December 4, 2017. That proceeding is pending and APS cannot predict the outcome of the proceeding.

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's focus is 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.

Table of Contents

On March 29, 2016, TransCanyon entered into a strategic alliance agreement with PG&E to jointly pursue competitive transmission opportunities solicited by the CAISO, the operator for the majority of California's transmission grid. TransCanyon and PG&E intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

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.

4CA. See "Four Corners - Asset Purchase Agreement and Coal Supply Matters" above for information regarding 4CA.

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.

Operating Revenues. For the years 2016 through 2018, retail electric revenues comprised approximately 95% of our total 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.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 1.7% for the year ended December 31, 2018 compared with the prior year. For the three years 2016 through 2018, APS's customer growth averaged 1.6% per year. We currently project annual customer growth to be 1.5 - 2.5% for 2019 and to average in the range of 1.5 - 2.5% for 2019 through 2021 based on our assessment of improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.1% for the year ended December 31, 2018 compared with the prior year.

Improving economic conditions and customer growth were offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives. For the three years 2016 through 2018, annual retail electricity sales were about flat, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 1.0 - 2.0% for 2019 and increase on average in the range of 1.5 - 2.5% during 2019 through 2021, 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 or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives 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 DG, 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 approximately $15 million.

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

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

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, unplanned outages, planned outages (typically scheduled in the spring and fall), renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors. See Note 2 for discussion of new accounting guidance related to the presentation of net periodic pension and postretirement benefit costs.

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 "Liquidity and Capital Resources" below for information regarding the planned additions to our facilities and income tax impacts related to bonus depreciation.

Pension and Other Postretirement Non-Service Credits - Net. Pension and other postretirement non-service credits can be impacted by changes in our actuarial assumptions. The most relevant actuarial assumptions are the discount rate used to measure our net periodic costs/credit, 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. See Note 2 for discussion of new accounting guidance related to the presentation of net periodic pension and postretirement benefit costs.

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 2018, 11.2% for 2017 and 2016. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units and transmission and distribution facilities.

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. On December 22, 2017, the Tax Act was enacted and was generally effective on January 1, 2018. Changes which will impact the Company include a reduction in the corporate tax rate to 21%, revisions to the rules related to tax bonus depreciation, limitations on interest deductibility and an associated exception for certain public utilities, and requirements that certain excess deferred tax amounts of regulated utilities be normalized. (See Note 4 for details of the impacts on the Company as of December 31, 2018.) In APS's recent general retail rate case, the ACC approved a Tax Expense

Adjustor Mechanism which will be used to pass through the income tax effects to retail customers of the Tax Act. (See Note 3 for details of the TEAM.)

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 – 2018 compared with 2017.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2018 was $511 million, compared with $488 million for the prior year. The results reflect an increase of approximately $19 million for the regulated electricity segment primarily due to higher revenue resulting from the retail regulatory settlement effective August 19, 2017, higher transmission revenues, higher retail revenues due to customer growth and higher average effective prices due to customer usage patterns and changes relating to customer program eligibility, partially offset by higher operations and maintenance expense and higher depreciation and amortization.

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

	Year Ended December 31,		
	2018	2017	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$2,590	$2,561	$ 29
Operations and maintenance	(1,025)	(936)	(89)
Depreciation and amortization	(581)	(532)	(49)
Taxes other than income taxes	(212)	(183)	(29)

Pension and other postretirement non-service credits - net	50	25	25
All other income and expenses, net	59	29	30
Interest charges, net of allowance for borrowed funds used during construction	(218)	(198)	(20)
Income taxes (Note 4)	(134)	(256)	122
Less income related to noncontrolling interests (Note 18)	(19)	(19)	—
Regulated electricity segment income	510	491	19
All other	1	(3)	4
Net Income Attributable to Common Shareholders	$511	$488	$ 23

65

Table of Contents

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $29 million higher for the year ended December 31, 2018 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)		
Impacts of retail regulatory settlement effective August 19, 2017 (Note 3)			
Increase in net retail base rates	$104	$ —	$ 104
Change in residential rate design and seasonal rates (a)	7	—	7
Higher transmission revenues (Note 3)	27	—	27
Higher retail revenues due to higher customer growth and changes in customer usage patterns, partially offset by the impacts of energy efficiency and distributed generation	26	2	24
Higher demand side management regulatory surcharges and renewable energy regulatory surcharges and purchased power, partially offset in operations and maintenance costs	1	(9)	10
Refunds due to lower federal corporate income tax rate (Note 3)	(143)	—	(143)
Effects of weather	(15)	(6)	(9)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	120	121	(1)
Miscellaneous items, net	3	(7)	10
Total	$130	$ 101	$ 29

(a) As part of the 2017 Settlement Agreement, rate design changes were implemented that moved some revenue responsibility from summer to non-summer months. The change was made to better align revenue collections with costs of service.

Operations and maintenance. Operations and maintenance expenses increased $89 million for the year ended December 31, 2018 compared with the prior-year period primarily because of:

- An increase of $37 million related to public outreach costs at the parent company primarily associated with the ballot initiative (see Note 3);

- An increase of $21 million in fossil generation costs primarily due to higher planned outage and operating costs;
- An increase of $12 million related to costs for renewable energy and similar regulatory programs, which was partially offset in operating revenues and purchased power;
- An increase of $11 million for costs related to information technology;
- An increase of $9 million in transmission, distribution, and customer service costs primarily due to maintenance costs and customer bad debt expense;
- An increase of $6 million to inform customers about APS's clean energy focus;

Table of Contents

- A decrease of $6 million related to employee benefit cost;
- A decrease of $5 million related to the absence of the Navajo Plant capital projects canceled in 2017 due to the expected plant retirement, which were deferred for regulatory recovery in depreciation; and
- An increase of $4 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $49 million higher for the year ended December 31, 2018 compared with the prior-year period primarily due to increased depreciation and amortization rates of $36 million, increased plant in service of $8 million and the absence of the regulatory deferral of the canceled capital projects in 2017 associated with the expected Navajo Plant retirement of $5 million.

Taxes other than income taxes. Taxes other than income taxes were $29 million higher for the year ended December 31, 2018 compared with the prior-year period primarily due to higher property values and the amortization of our property tax deferral regulatory asset.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $25 million higher for the year ended December 31, 2018 compared to the prior-year period primarily due to higher market returns and the adoption of new pension and other postretirement accounting guidance in 2018 (see Notes 2 and 7).

All other income and expenses, net. All other income and expenses, net were $30 million higher for the year ended December 31, 2018 compared with the prior-year period primarily due to the debt return on the Four Corners SCR deferrals (Note 3) and increased allowance for equity funds used during construction.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, were $20 million higher for the year ended December 31, 2018 compared with the prior-year period primarily due to higher debt balances in the current period.

Income taxes. Income taxes were $122 million lower for the year ended December 31, 2018 compared with the prior-year period primarily due to the effects of the federal tax reform and lower pretax income in the current year period, partially offset by certain non-deductible costs (See Note 4).

67

Table of Contents

Operating Results – 2017 compared with 2016.

Our consolidated net income attributable to common shareholders for the year ended December 31, 2017 was $488 million, compared with $442 million for the prior year. The results reflect an increase of approximately $48 million for the regulated electricity segment primarily due to higher revenue resulting from the retail regulatory settlement effective August 19, 2017, higher transmission revenues, higher retail revenues due to customer growth and higher average effective prices due to customer usage patterns and changes relating to customer program eligibility, partially offset by higher depreciation and amortization primarily due to increased plant in service and higher depreciation and amortization rates.

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

	Year Ended December 31, 2017	2016	Net change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$2,561	$2,407	$ 154
Operations and maintenance	(936)	(926)	(10)
Depreciation and amortization	(532)	(485)	(47)
Taxes other than income taxes	(183)	(166)	(17)
Pension and other postretirement non-service credits - net	25	20	5
All other income and expenses, net	29	35	(6)
Interest charges, net of allowance for borrowed funds used during construction	(198)	(186)	(12)
Income taxes	(256)	(237)	(19)
Less income related to noncontrolling interests (Note 18)	(19)	(19)	—
Regulated electricity segment income	491	443	48
All other	(3)	(1)	(2)
Net Income Attributable to Common Shareholders	$488	$442	$ 46

Table of Contents

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $154 million higher for the year ended December 31, 2017 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)		
Impacts of retail regulatory settlement effective August 19, 2017 (Note 4)	$55	$ —	$ 55
Transmission revenues (Note 4):			
Higher transmission revenues	30	—	30
Absence of 2016 FERC disallowance	12	—	12
Higher retail revenues due to customer growth and higher average effective prices due to customer usage patterns and changes relating to customer program participation (a)	21	(3)	24
Lost fixed cost recovery	14	—	14
Effects of weather	9	3	6
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(83)	(92)	9
Higher demand side management regulatory surcharges and renewable energy regulatory surcharges and purchased power partially offset in operations and maintenance costs	9	2	7
Miscellaneous items, net	(3)	—	(3)
Total	$64	$ (90)	$ 154

(a) Partially offset by the impacts of efficiency programs and distributed generation.

Operations and maintenance. Operations and maintenance expenses increased $10 million for the year ended December 31, 2017 compared with the prior year primarily because of:

- An increase of $15 million for employee benefit costs;

- An increase of $9 million for costs primarily related to information technology and other corporate support;

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An increase 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 $5 million related to the Navajo Plant capital projects canceled due to the expected plant retirement, which were deferred for regulatory recovery in depreciation;
- A decrease of $12 million for lower Palo Verde operating costs;
- A decrease of $11 million in fossil generation costs primarily due to less planned outage activity in the current year and lower Navajo Plant costs;

Table of Contents

- A decrease of $5 million primarily due to the absence of 2016 costs to support the Company's positions on a solar net metering ballot initiative in Arizona; and

- An increase of $1 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $47 million higher for the year ended December 31, 2017 compared with the prior year primarily related to increased plant in service of $32 million and increased depreciation and amortization rates of $19 million, partially offset by the regulatory deferral of the canceled capital projects associated with the expected Navajo Plant retirement of $5 million.

Taxes other than income taxes. Taxes other than income taxes were $17 million higher for the year ended December 31, 2017 compared with the prior year primarily due to higher property values and the amortization of our property tax deferral regulatory asset.

Pension and other postretirement non-service credits, net. Pension and other postretirement non-service credits, net were $5 million higher for the year ended December 31, 2017 compared to the prior-year period primarily due to higher market returns.

All other income and expenses, net. All other income and expenses, net, were $6 million lower for the year ended December 31, 2017 compared with the prior year primarily due to the absence of a gain on sale of a transmission line, which occurred in 2016.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, increased $12 million for the year ended December 31, 2017 compared with the prior year, primarily because of higher debt balances in the current year.

Income taxes. Income taxes were $19 million higher for the year ended December 31, 2017 compared with the prior year primarily due to the effects of higher pretax income in the current year and the effects of the federal tax reform, partially offset by a lower effective tax rate primarily due to stock compensation. The stock compensation guidance requires all excess income tax benefits and deficiencies arising from share-based payments to be recognized in earnings in the period they occur, which causes effective tax rate fluctuations when stock compensation payouts occur.

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, 2018, APS's common equity ratio, as defined, was 54%. Its total shareholder equity was approximately $5.7 billion, and total capitalization was approximately $10.5 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $4.2 billion,

Table of Contents

assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

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

On December 20, 2018, the Joint Committee on Taxation ("JCT") released the general explanation of the Tax Act. The document - commonly referred to as the "Blue Book" - provides a comprehensive technical description of the Tax Act and includes the legislative intent of Congress with respect to the changes made by provisions of the Tax Act. The "Blue Book" provides clarification that the intent of the Tax Act was to exclude from the definition of bonus depreciation qualified property any property placed in service by a regulated public utility after December 31, 2017. As a result, the Company currently does not anticipate recognizing any cash tax benefits related to bonus depreciation for property placed in service on or after January 1, 2018 (See Note 4).

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, 2018, 2017 and 2016 (dollars in millions):

Pinnacle West Consolidated

	2018	2017	2016
Net cash flow provided by operating activities	$1,277	$1,118	$1,023
Net cash flow used for investing activities	(1,193)	(1,429)	(1,252)
Net cash flow provided by (used for) financing activities	(92)	316	198
Net increase (decrease) in cash and cash equivalents	$(8)	$5	$(31)

Arizona Public Service Company

	2018	2017	2016
Net cash flow provided by operating activities	$1,255	$1,162	$1,010
Net cash flow used for investing activities	(1,187)	(1,401)	(1,219)
Net cash flow provided by (used for) financing activities	(76)	244	196
Net increase (decrease) in cash and cash equivalents	$(8)	$5	$(13)

Operating Cash Flows

2018 Compared with 2017. Pinnacle West’s consolidated net cash provided by operating activities was $1,277 million in 2018 compared to $1,118 million in 2017. The increase of $159 million in net cash provided is primarily due to higher cash receipts from operating activities as a result of the retail regulatory settlement effective August 19, 2017, higher transmission receipts and higher receipts due to customer growth and higher average effective prices. These items are partially offset by higher payments for operations and maintenance, income taxes, other taxes and interest. The difference between APS and Pinnacle West's net cash provided by operating activities primarily relates to Pinnacle West's cash payments for 4CA's operating costs and differences in other operating cash payments.

2017 Compared with 2016. Pinnacle West’s consolidated net cash provided by operating activities was $1,118 million in 2017 compared to $1,023 million in 2016. The increase of $95 million in net cash provided

Table of Contents

is primarily due to lower payments of operations and maintenance, fuel and purchased power costs and higher cash receipts, partially offset by no collateral posted in 2017 compared to $17 million returned in 2016. The difference between APS and Pinnacle West's net cash provided by operating activities primarily relates to Pinnacle West's cash payments for 4CA's operating costs and differences in other operating cash payments.

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 110% funded as of January 1, 2019 and 117% as of January 1, 2018. Under GAAP, the qualified pension plan was 90% funded as of January 1, 2019 and 95% funded as of January 1, 2018. 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 $50 million in 2018, $100 million in 2017, and $100 million in 2016. 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 $350 million during the 2019-2021 period. With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2018. We made a contribution of approximately $1 million in each of 2017 and 2016. We do not expect to make any contributions over the next three years to our other postretirement benefit plans. In 2018, the Company was reimbursed $72 million for prior years retiree medical claims from the other postretirement benefit plan trust assets.

Because of plan changes in 2014, the Company sought IRS approval to move approximately $186 million of other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs. In December 2016, FERC approved a methodology for determining the amount of other postretirement benefit trust assets to transfer into a new trust account to pay for active union employee medical costs. On January 2, 2018, these funds were moved to the new trust account, which is included in the other special use funds on the Consolidated Balance Sheets. The Company and the IRS executed a final Closing Agreement on March 2, 2018. The Company made an informational filing with FERC during February 2018. It is the Company’s understanding that completion of these regulatory requirements permits access to approximately $186 million for the sole purpose of paying active union employee medical benefits.

Investing Cash Flows

2018 Compared with 2017. Pinnacle West’s consolidated net cash used for investing activities was $1,193 million in 2018, compared to $1,429 million in 2017. The decrease of $236 million in net cash used primarily related to decreased capital expenditures. The difference between APS and Pinnacle West's net cash used for investing activities primarily relates to Pinnacle West's investing cash activity related to 4CA.

2017 Compared with 2016. Pinnacle West’s consolidated net cash used for investing activities was $1,429 million in 2017, compared to $1,252 million in 2016. The increase of $177 million in net cash used primarily related to increased capital expenditures.

Table of Contents

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,		
	2019	**2020**	**2021**
APS			
Generation:			
Clean:			
Nuclear Fuel	$72	$64	$64
Nuclear Generation	70	68	67
Renewables (a)	16	18	3
New Resources (b)	77	119	305
Environmental	30	40	71
New Gas Generation	16	—	—
Other Generation	109	116	108
Distribution	508	462	559
Transmission	202	169	199
Other (c)	126	147	108
Total APS	$1,226	$1,203	$1,484

(a) Primarily APS Solar Communities program
(b) Projected future generation resources, which may include energy storage, renewable projects, and other clean energy projects
(c) Primarily information systems and facilities projects

Generation capital expenditures are comprised of various additions and improvements to APS's clean resources, including nuclear plants, renewables and projected future new resources. Generation capital expenditures also include improvements to existing fossil plants. Examples of the types of projects included in the forecast of generation capital expenditures are additions of roof top solar systems, new clean resources, and upgrades and capital replacements of various nuclear and fossil power plant equipment, such as turbines, boilers and environmental equipment. We are monitoring the status of environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

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

Financing Cash Flows and Liquidity

2018 Compared with 2017. Pinnacle West's consolidated net cash used for financing activities was $92 million in 2018, compared to $316 million of net cash provided in 2017, an increase of $408 million in net cash used. The increase in net cash used by financing activities includes $403 million in lower issuances of long-term debt, higher long-term debt repayments of $57 million and higher dividend payments of $19 million through December 31, 2018, which are partially offset by $63 million in lower net short-term debt.

APS's consolidated net cash used by financing activities was$76 million in 2018, compared to $244 million of net cash provided in 2017, an increase of $320 million in net cash used. The increase in net cash used by financing activities includes $254 million in lower issuances of long-term debt, higher long-term debt repayments of $182 million and higher dividend payments of $19 million through December 31, 2018, which are partially offset by $136 million in lower net short-term debt.

2017 Compared with 2016. Pinnacle West's consolidated net cash provided by financing activities was $316 million in 2017, compared to $198 million in 2016, an increase of $118 million in net cash provided. The net cash provided by financing activities includes $245 million in lower long-term debt repayments and $155 million higher issuances of long-term debt through December 31, 2017, partially offset by a $259 million net decrease in short-term borrowings and $16 million of higher dividend payments.

APS's consolidated net cash provided by financing activities was $244 million in 2017, compared to $196 million in 2016, an increase of $48 million in net cash provided. The net cash provided by financing activities includes $370 million in lower long-term debt repayments and $108 million in higher equity infusions from Pinnacle West, partially offset by $143 million lower issuances of long-term debt through December 31, 2017, $271 million net decrease in short-term borrowings and $16 million of higher dividend payments.

Significant Financing Activities. On December 19, 2018, the Pinnacle West Board of Directors declared a dividend of $0.7375 per share of common stock, payable on March 1, 2019 to shareholders of record on February 1, 2019. During 2018, Pinnacle West increased its indicated annual dividend from $2.78 per share to $2.95 per share. For the year ended December 31, 2018, Pinnacle West's total dividends paid per share of common stock were $2.82 per share, which resulted in dividend payments of $309 million.

On May 30, 2018, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series C, due 2029. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2017.

On June 26, 2018, APS repaid at maturity APS's $50 million term loan facility.

On August 9, 2018, APS issued $300 million of 4.20% unsecured senior notes that mature on August 15, 2048. The net proceeds from the sale of the notes were used to repay commercial paper borrowings.

On November 30, 2018, APS repaid its $100 million term loan facility that would have matured April 22, 2019.

On December 21, 2018, Pinnacle West entered into a $150 million term loan facility that matures December 2020. The proceeds were used for general corporate purposes.

On December 21, 2018, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

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

On June 28, 2018, Pinnacle West refinanced its 364-day $125 million unsecured revolving credit facility that would have matured on July 30, 2018 with a new 364-day $150 million credit facility that matures June 27, 2019. Borrowings under the facility bear interest at LIBOR plus 0.70% per annum. At December 31, 2018, Pinnacle West had $54 million outstanding under the facility.

On July 12, 2018, Pinnacle West replaced its $200 million revolving credit facility that would have matured in May 2021, with a new $200 million facility that matures in July 2023. 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, 2018, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $22 million of commercial paper borrowings.

On July 12, 2018, APS replaced its $500 million revolving credit facility that would have matured in May 2021, with a new $500 million facility that matures in July 2023.

At December 31, 2018, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and the above-mentioned $500 million facility. APS may increase the amount of each facility up to a maximum of $700 million, 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 $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2018, APS had no commercial paper outstanding and 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.

Other Financing Matters. 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, 2018, the ratio was approximately 50% 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.

See Note 6 for further discussions of liquidity matters.

Table of Contents

Credit Ratings

The ratings of securities of Pinnacle West and APS as of February 15, 2019 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-
Senior unsecured	A3	BBB+	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.

Table of Contents

Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2018 (dollars in millions):

	2019	2020-2021	2022-2023	Thereafter	Total
Long-term debt payments, including interest: (a)					
APS	$695	$589	$336	$6,419	$8,039
Pinnacle West	12	461	—	—	473
Total long-term debt payments, including interest	707	1,050	336	6,419	8,512
Short-term debt payments, including interest (b)	76	—	—	—	76
Fuel and purchased power commitments (c)	574	1,093	1,103	5,701	8,471
Renewable energy credits (d)	37	70	61	155	323
Purchase obligations (e)	48	20	20	206	294
Coal reclamation	32	42	46	167	287
Nuclear decommissioning funding requirements	2	4	4	52	62
Noncontrolling interests (f)	23	46	46	159	274
Operating lease payments (g)	14	22	12	42	90
Total contractual commitments	$1,513	$2,347	$1,628	$12,901	$18,389

(a) The long-term debt matures at various dates through 2048 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using average rates at December 31, 2018 (see Note 6).

(b) See Note 5 - Lines of credit and short-term borrowings for further details.

(c) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation (see Notes 3 and 10).

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

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

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

(g) Commitments relating to purchased power lease contracts are included within the fuel and purchased power commitments line above.

This table excludes $41 million in unrecognized tax benefits because the timing of the future cash outflows is uncertain. Estimated minimum required pension contributions are zero for 2019, 2020 and 2021 (see Note 7).

CRITICAL ACCOUNTING POLICIES

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

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred and are refundable to 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, except for pension benefits which would be charged to OCI and result in lower future earnings. We had $1,510 million of regulatory assets and $2,492 million of regulatory liabilities on the Consolidated Balance Sheets at December 31, 2018.

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.

On January 1, 2018, we adopted new accounting standard ASU 2017-07, Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This new standard changed our income statement presentation of net periodic benefit cost and allows only the service cost component of periodic net benefit cost to be eligible for capitalization. See Note 2 for additional information.

Table of Contents

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2018 reported pension liability on the Consolidated Balance Sheets and our 2018 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):

Actuarial Assumption (a)	**Increase (Decrease) Impact on Pension Liability**	**Impact on Pension Expense**
Discount rate:		
Increase 1%	$ (328)	$ (12)
Decrease 1%	397	15
Expected long-term rate of return on plan assets:		
Increase 1%	—	(21)
Decrease 1%	—	21

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

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the December 31, 2018 other postretirement benefit obligation and our 2018 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%	$ (85)	$ (1)
Decrease 1%	108	6
Healthcare cost trend rate (b):		
Increase 1%	101	10
Decrease 1%	(81)	(4)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	—	(5)
Decrease 1%	—	5

(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 Notes 2 and 7 for further details about our pension and other postretirement benefit plans.

Table of Contents

Fair Value Measurements

We account for derivative instruments, investments held in our nuclear decommissioning trust fund, investments held in our other special use funds, 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 of accounting policies and Note 13 for fair value measurement disclosures.

Asset Retirement Obligations

We recognize an ARO for the future decommissioning or retirement of our tangible long-lived assets for which a legal obligation exists. The ARO liability represents an estimate of the fair value of the current obligation related to decommissioning and the retirement of those assets. ARO measurements inherently involve uncertainty in the amount and timing of settlement of the liability. We use an expected cash flow approach to measure the amount we recognize as an ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the asset’s current license or lease term and expected decommissioning dates. The fair value of an ARO is recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and are depreciated over the life of the related assets. In addition, we accrete the ARO liability to reflect the passage of time. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. In accordance with GAAP accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal.

AROs as of December 31, 2018 are described further in Note 11.

Income Taxes

Our income tax expense, deferred tax assets and liabilities, and liabilities for unrecognized tax benefits reflect management's best estimate of current and future taxes to be paid.

On December 22, 2017, the Tax Act was enacted, and is generally effective January 1, 2018. This legislation made significant changes to the federal income tax laws. Changes which impact the Company include, but are not limited to, a reduction in the corporate tax rate to 21%, revisions to the rules related to tax bonus depreciation, limitations on interest deductibility and an associated exception for certain public utility property, and requirements that certain excess deferred tax amounts of regulated utilities be normalized.

Deferred tax assets or liabilities are recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carryforwards and net operating loss carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period the change is enacted. Given the regulatory nature of the Company's business, substantially all of the effect on deferred tax assets and liabilities for the reduction in the federal corporate tax

rate to 21% was recorded as a regulatory liability recoverable by ratepayers as of December 31, 2017. See Note 3 for further discussion of the accounting for the regulatory liability.
The calculation of our tax liabilities involves dealing with the application of complex laws and regulations which are voluminous and often ambiguous. Interpretations and guidance surrounding income tax laws and regulations change over time. Tax positions taken by Pinnacle West on its income tax returns that are recognized in the financial statements must satisfy a "more likely than not" recognition threshold, assuming that the position will be sustained upon examination by taxing authorities with full knowledge of all relevant information, including resolutions of any related appeals or litigation processes, on the basis of the technical merits. Additional guidance may be issued through legislation, Treasury regulations, or other technical guidance, which may materially affect amounts the Company has recognized in its financial statements.
We record unrecognized tax benefits for tax positions that may not satisfy this "more likely than not" recognition threshold as liabilities in accordance with generally accepted accounting principles. These liabilities are adjusted when management judgment changes as a result of the evaluation of new information not previously available. These changes will be reflected as an increase or decrease to income tax expense in the period in which new information is available.

OTHER ACCOUNTING MATTERS
We adopted the following new accounting standards on January 1, 2018:

- ASU 2014-09: Revenue from Contracts with Customers, and related amendments
- ASU 2016-01: Financial Instruments, Recognition and Measurement
- ASU 2016-15: Statement of Cash Flows, Classification of Certain Cash Receipts and Cash Payments
- ASU 2016-18: Statement of Cash Flows, Restricted Cash
- ASU 2017-01: Business Combinations, Clarifying the Definition of a Business
- ASU 2017-05: Other Income, Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets
- ASU 2017-07: Compensation-Retirement Benefits, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

- ASU 2018-02: Income Statement-Reporting Comprehensive Income, Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

We adopted the following new accounting standards on January 1, 2019:

- ASU 2016-02: Leases, and related amendments

- ASU 2017-12: Derivatives and Hedging, Targeted Improvements to Accounting for Hedging Activities

We are currently evaluating the impacts of the pending adoption of the following new accounting standards effective for us on January 1, 2020:

Table of Contents

- ASU 2016-13: Financial Instruments, Measurement of Credit Losses
- ASU 2018-15: Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract

See Note 2 for additional information related to new accounting standards.

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, other special use funds (see Note 13 and Note 19), and benefit plan assets. The nuclear decommissioning trust, other special use funds 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, 2018 and 2017. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2018 and 2017 (dollars in millions):

Pinnacle West – Consolidated

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
2018	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**	**Interest Rates**	**Amount**
2019	2.99%	$ 76	—	—	8.75%	$500
2020	—	—	3.02 %	150	2.23%	550

2021	—	—	—	—	—	—
2022	—	—	—	—	—	—
2023	—	—	—	—	—	—
Years thereafter	—	—	1.76 %	36	4.25%	3,940
Total		$ 76		$ 186		$4,990
Fair value		$ 76		$ 186		$5,048

Table of Contents

2017	Short-Term Debt Interest Rates	Amount	Variable-Rate Long-Term Debt Interest Rates	Amount	Fixed-Rate Long-Term Debt Interest Rates	Amount
2018	2.14%	$ 95	2.17 %	$ 50	1.75%	$32
2019	—	—	2.27 %	100	8.75%	500
2020	—	—	—	—	2.23%	550
2021	—	—	—	—	—	—
2022	—	—	—	—	—	—
Years thereafter	—	—	1.77 %	36	4.25%	3,640
Total		$ 95		$ 186		$4,722
Fair value		$ 95		$ 186		$5,119

The tables below present contractual balances of APS's long-term and short-term debt at the expected maturity dates, as well as the fair value of those instruments on December 31, 2018 and 2017. The interest rates presented in the tables below represent the weighted-average interest rates as of December 31, 2018 and 2017 (dollars in millions):

APS — Consolidated

2018	Variable-Rate Long-Term Debt Interest Rates	Amount	Fixed-Rate Long-Term Debt Interest Rates	Amount
2019	—	—	8.75%	$500
2020	—	—	2.20%	250
2021	—	—	—	—
2022	—	—	—	—
2023	—	—	—	—
Years thereafter	1.76 %	36	4.25%	3,940
Total		$ 36		$4,690
Fair value		$ 36		$4,754

2017	Variable-Rate Long-Term Debt Interest Rates	Amount	Fixed-Rate Long-Term Debt Interest Rates	Amount
2018	2.17 %	$ 50	1.75%	$32
2019	2.27 %	100	8.75%	500
2020	—	—	2.20%	250
2021	—	—	—	—
2022	—	—	—	—

Years thereafter	1.77 %	36	4.25%	3,640
Total		$ 186		$4,422
Fair value		$ 186		$4,820

Table of Contents

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 2018 and 2017 (dollars in millions):

	2018	2017
Mark-to-market of net positions at beginning of year	$(91)	$(49)
Decrease (Increase) in regulatory asset	31	(46)
Recognized in OCI:		
Mark-to-market losses realized during the period	2	4
Change in valuation techniques	—	—
Mark-to-market of net positions at end of year	$(58)	$(91)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at December 31, 2018 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	2019	2020	2021	2022	2023	Total fair value
Observable prices provided by other external sources	$(29)	$(10)	$(7)	$(4)	$ —	$(50)
Prices based on unobservable inputs	(4)	(4)	—	—	—	(8)
Total by maturity	$(33)	$(14)	$(7)	$(4)	$ —	$(58)

84

Table of Contents

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, 2018 and 2017 (dollars in millions):

	December 31, 2018		**December 31, 2017**	
	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) (a)				
Electricity	$ 1	$ (1)	$ 1	$ (1)
Natural gas	44	(44)	45	(45)
Total	$ 45	$ (45)	$ 46	$ (46)

(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.

Table of Contents

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, 2018. The effectiveness of our internal control over financial reporting as of December 31, 2018 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 22, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Pinnacle West Capital Corporation
Phoenix, Arizona

Opinions on the Financial Statements and Internal Control over Financial Reporting
We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2018 and 2017, 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, 2018, the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company’s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

Basis for Opinions
The Company’s management is responsible for these financial statements, 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 an opinion on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. 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.

Table of Contents

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 22, 2019

We have served as the Company's auditor since 1932.

Table of Contents

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

	Year Ended December 31, 2018	2017	2016
OPERATING REVENUES (NOTE 20)	$3,691,247	$3,565,296	$3,498,682
OPERATING EXPENSES			
Fuel and purchased power	1,076,116	981,301	1,075,510
Operations and maintenance	1,036,744	949,107	931,692
Depreciation and amortization	582,354	534,118	485,829
Taxes other than income taxes	212,849	184,347	166,499
Other expenses	9,497	6,660	3,541
Total	2,917,560	2,655,533	2,663,071
OPERATING INCOME	773,687	909,763	835,611
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	52,319	47,011	42,140
Pension and other postretirement non-service credits - net (Note 7)	49,791	24,664	20,373
Other income (Note 17)	24,896	4,006	901
Other expense (Note 17)	(17,966)	(21,539)	(15,337)
Total	109,040	54,142	48,077
INTEREST EXPENSE			
Interest charges	243,465	219,796	205,720
Allowance for borrowed funds used during construction (Note 1)	(25,180)	(22,112)	(19,970)
Total	218,285	197,684	185,750
INCOME BEFORE INCOME TAXES	664,442	766,221	697,938
INCOME TAXES (Note 4)	133,902	258,272	236,411
NET INCOME	530,540	507,949	461,527
Less: Net income attributable to noncontrolling interests (Note 18)	19,493	19,493	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$511,047	$488,456	$442,034
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	112,129	111,839	111,409
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,550	112,367	112,046
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Net income attributable to common shareholders — basic	$4.56	$4.37	$3.97
Net income attributable to common shareholders — diluted	$4.54	$4.35	$3.95

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

Table of Contents

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

	Year Ended December 31,		
	2018	2017	2016
NET INCOME	$530,540	$507,949	$461,527
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of ($78), $24, and ($585) (Note 16)	(78)	(35)	(538)
Reclassification of net realized loss, net of tax benefit of $473, $1,294, and $985 (Note 16)	1,527	2,225	2,941
Pension and other postretirement benefits activity, net of tax benefit (expense) of ($1,585), $693, and $633 (Note 7)	4,397	(3,370)	(1,477)
Total other comprehensive income (loss)	5,846	(1,180)	926
COMPREHENSIVE INCOME	536,386	506,769	462,453
Less: Comprehensive income attributable to noncontrolling interests	19,493	19,493	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$516,893	$487,276	$442,960

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

Table of Contents

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

	December 31, 2018	2017
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$5,766	$13,892
Customer and other receivables	267,887	305,147
Accrued unbilled revenues	137,170	112,434
Allowance for doubtful accounts	(4,069)	(2,513)
Materials and supplies (at average cost)	269,065	264,012
Fossil fuel (at average cost)	25,029	25,258
Assets from risk management activities (Note 16)	1,113	1,931
Deferred fuel and purchased power regulatory asset (Note 3)	37,164	75,637
Other regulatory assets (Note 3)	129,738	172,451
Other current assets	56,128	48,039
Total current assets	924,991	1,016,288
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 13 and 19)	851,134	871,000
Other special use funds (Notes 13 and 19)	236,101	32,542
Other assets	103,247	52,040
Total investments and other assets	1,190,482	955,582
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	18,736,628	17,798,061
Accumulated depreciation and amortization	(6,366,014)	(6,128,535)
Net	12,370,614	11,669,526
Construction work in progress	1,170,062	1,291,498
Palo Verde sale leaseback, net of accumulated depreciation of $245,275 and $241,405 (Note 18)	105,775	109,645
Intangible assets, net of accumulated amortization of $591,202 and $582,272	262,902	257,189
Nuclear fuel, net of accumulated amortization of $137,850 and $144,070	120,217	117,408
Total property, plant and equipment	14,029,570	13,445,266
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	1,342,941	1,202,302
Assets for other postretirement benefits (Note 7)	46,906	268,978
Other	129,312	130,666
Total deferred debits	1,519,159	1,601,946
TOTAL ASSETS	$17,664,202	$17,019,082

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

Table of Contents

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

	December 31, 2018	2017
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$277,336	$256,442
Accrued taxes	154,819	148,946
Accrued interest	61,107	56,397
Common dividends payable	82,675	77,667
Short-term borrowings (Note 5)	76,400	95,400
Current maturities of long-term debt (Note 6)	500,000	82,000
Customer deposits	91,174	70,388
Liabilities from risk management activities (Note 16)	35,506	59,252
Liabilities for asset retirements (Note 11)	19,842	4,745
Regulatory liabilities (Note 3)	165,876	100,086
Other current liabilities	184,229	246,529
Total current liabilities	1,648,964	1,197,852
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 6)	4,638,232	4,789,713
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,807,421	1,690,805
Regulatory liabilities (Notes 1, 3, 4 and 7)	2,325,976	2,452,536
Liabilities for asset retirements (Note 11)	706,703	674,784
Liabilities for pension benefits (Note 7)	443,170	327,300
Liabilities from risk management activities (Note 16)	24,531	37,170
Customer advances	137,153	113,996
Coal mine reclamation	212,785	231,597
Deferred investment tax credit	200,405	205,575
Unrecognized tax benefits (Note 4)	22,517	13,115
Other	147,640	148,909
Total deferred credits and other	6,028,301	5,895,787
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 112,159,896 and 111,816,170 issued at respective dates	2,634,265	2,614,805
Treasury stock at cost; 58,135 shares at end of 2018 and 64,463 shares at end of 2017	(4,825)	(5,624)
Total common stock	2,629,440	2,609,181
Retained earnings	2,641,183	2,442,511
Accumulated other comprehensive loss (Note 21)	(47,708)	(45,002)
Total shareholders' equity	5,222,915	5,006,690
Noncontrolling interests (Note 18)	125,790	129,040
Total equity	5,348,705	5,135,730
TOTAL LIABILITIES AND EQUITY	$17,664,202	$17,019,082

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

Table of Contents

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

	Year Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$530,540	$507,949	$461,527
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	650,955	610,629	565,011
Deferred fuel and purchased power	(78,277)	(48,405)	(60,303)
Deferred fuel and purchased power amortization	116,750	(14,767)	38,152
Allowance for equity funds used during construction	(52,319)	(47,011)	(42,140)
Deferred income taxes	117,355	248,164	206,870
Deferred investment tax credit	(5,170)	(4,587)	23,082
Change in derivative instruments fair value	—	(373)	(403)
Stock compensation	19,547	20,502	18,883
Changes in current assets and liabilities:			
Customer and other receivables	37,530	(93,797)	(2,489)
Accrued unbilled revenues	(24,736)	(4,485)	(11,709)
Materials, supplies and fossil fuel	(6,103)	(6,683)	(1,491)
Income tax receivable	—	3,751	(3,162)
Other current assets	33,844	(10,580)	(23,324)
Accounts payable	(14,602)	(23,769)	(66,917)
Accrued taxes	6,597	9,982	447
Other current liabilities	28,174	19,154	29,594
Change in margin and collateral accounts — assets	143	(300)	673
Change in margin and collateral accounts — liabilities	(2,211)	(533)	17,735
Change in unrecognized tax benefits	(1,235)	5,891	1,628
Change in long-term regulatory liabilities	(109,284)	45,764	14,682
Change in other long-term assets	78,604	(68,480)	(60,163)
Change in other long-term liabilities	(48,958)	(29,980)	(82,793)
Net cash flow provided by operating activities	1,277,144	1,118,036	1,023,390
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,178,169)	(1,408,774)	(1,275,472)
Contributions in aid of construction	27,716	23,708	64,296
Allowance for borrowed funds used during construction	(25,180)	(22,112)	(19,970)
Proceeds from nuclear decommissioning trust sales and other special use funds	653,033	542,246	633,410
Investment in nuclear decommissioning trust and other special use funds	(672,165)	(544,527)	(635,691)
Other	1,941	(19,078)	(18,651)
Net cash flow used for investing activities	(1,192,824)	(1,428,537)	(1,252,078)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	445,245	848,239	693,151
Repayment of long-term debt	(182,000)	(125,000)	(370,430)
Short-term borrowings and (repayments) — net	(7,000)	(107,800)	137,200
Short-term debt borrowings under revolving credit facility	45,000	58,000	40,000
Short-term debt repayments under revolving credit facility	(57,000)	(32,000)	—
Dividends paid on common stock	(308,892)	(289,793)	(274,229)

Common stock equity issuance and purchases - net	(5,055)	(13,390)	(4,867)
Distributions to noncontrolling interests	(22,744)	(22,744)	(22,744)
Net cash flow (used for) provided by financing activities	(92,446)	315,512	198,081
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(8,126)	5,011	(30,607)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	13,892	8,881	39,488
CASH AND CASH EQUIVALENTS AT END OF YEAR	$5,766	$13,892	$8,881

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

Table of Contents

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, 2015	111,095,402	$2,541,668	(115,030)	$(5,806)	$2,092,803	$ (44,748)	$ 135,540	$4,719,457
Net income		—		—	442,034	—	19,493	461,527
Other comprehensive income		—		—	—	926	—	926
Dividends on common stock ($2.56 per share)		—		—	(284,765)	—	—	(284,765)
Issuance of common stock	296,651	13,982		—	—	—	—	13,982
Purchase of treasury stock (a)		—	(128,105)	(9,087)	—	—	—	(9,087)
Reissuance of treasury stock for stock-based compensation and other		—	187,818	10,760	—	—	—	10,760
Stock compensation cumulative effect adjustments (b)		40,380		—	5,475	—	—	45,855
Net capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Balance, December 31, 2016	111,392,053	2,596,030	(55,317)	(4,133)	2,255,547	(43,822)	132,290	4,935,912
Net income		—		—	488,456	—	19,493	507,949
Other comprehensive loss		—		—	—	(1,180)	—	(1,180)
Dividends on common stock ($2.70 per share)		—		—	(301,492)	—	—	(301,492)
Issuance of common stock	424,117	18,775		—	—	—	—	18,775
Purchase of treasury stock (a)		—	(216,911)	(17,755)	—	—	—	(17,755)
Reissuance of treasury stock for stock-based compensation and other		—	207,765	16,264	—	—	—	16,264
Net capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Balance, December 31, 2017	111,816,170	2,614,805	(64,463)	(5,624)	2,442,511	(45,002)	129,040	5,135,730
Net income		—		—	511,047	—	19,493	530,540
Other comprehensive income		—		—	—	5,846	—	5,846
Dividends on common stock ($2.87 per share)		—		—	(320,927)	—	—	(320,927)
Issuance of common stock	343,726	19,460		—	—	—	—	19,460
Purchase of treasury stock (a)		—	(129,903)	(10,338)	—	—	—	(10,338)
Reissuance of treasury stock for stock-based compensation and other		—	136,231	11,137	—	—	—	11,137
Net capital activities by noncontrolling interests		—		—	—	—	(22,743)	(22,743)
Reclassification of income tax effects related to new tax reform (See Note 2)		—		—	8,552	(8,552)	—	—
Balance, December 31, 2018	112,159,896	$2,634,265	(58,135)	$(4,825)	$2,641,183	$ (47,708)	$ 125,790	$5,348,705

(a) Primarily represents shares of common stock withheld from certain stock awards for tax purposes.
(b) During 2016, we adopted new stock-based compensation accounting guidance.

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

Table of Contents

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, 2018. The effectiveness of our internal control over financial reporting as of December 31, 2018 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 22, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinions on the Financial Statements and Internal Control over Financial Reporting
We have audited the accompanying consolidated balance sheets of Arizona Public Service Company and subsidiaries (the "Company") as of December 31, 2018 and 2017, 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, 2018, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company’s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

Basis for Opinions
The Company’s management is responsible for these financial statements, 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 an opinion on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. 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.

Table of Contents

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Phoenix, Arizona
February 22, 2019

We have served as the Company's auditor since 1932.

Table of Contents

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

	Year Ended December 31,		
	2018	2017	2016
OPERATING REVENUES	$3,688,342	$3,557,652	$3,498,090
OPERATING EXPENSES			
Fuel and purchased power	1,094,020	992,744	1,082,625
Operations and maintenance	969,227	917,983	902,467
Depreciation and amortization	580,694	532,423	484,909
Taxes other than income taxes	212,136	183,254	166,064
Other expense	2,497	6,709	3,540
Total	2,858,574	2,633,113	2,639,605
OPERATING INCOME	829,768	924,539	858,485
OTHER INCOME (DEDUCTIONS)			
Allowance for equity funds used during construction (Note 1)	52,319	47,011	42,140
Pension and other postretirement non-service credits - net (Note 7)	51,242	24,371	20,224
Other income (Note 17)	22,746	3,013	271
Other expense (Note 17)	(15,292)	(13,913)	(10,554)
Total	111,015	60,482	52,081
INTEREST EXPENSE			
Interest charges	231,391	214,163	202,571
Allowance for borrowed funds used during construction (Note 1)	(25,180)	(22,112)	(19,481)
Total	206,211	192,051	183,090
INCOME BEFORE INCOME TAXES	734,572	792,970	727,476
INCOME TAXES (Note 4)	144,814	269,168	245,842
NET INCOME	589,758	523,802	481,634
Less: Net income attributable to noncontrolling interests (Note 18)	19,493	19,493	19,493
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$570,265	$504,309	$462,141

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

Table of Contents

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

	Year Ended December 31, 2018	2017	2016
NET INCOME	$589,758	$523,802	$481,634
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Derivative instruments:			
Net unrealized loss, net of tax benefit (expense) of ($78), $24, and ($585) (Note 16)	(78)	(35)	(538)
Reclassification of net realized loss, net of tax benefit of $473, $1,294, and $985 (Note 16)	1,527	2,225	2,941
Pension and other postretirement benefits activity, net of tax benefit (expense) of ($1,159), $977, and $293 (Note 7)	3,465	(3,750)	(729)
Total other comprehensive income (loss)	4,914	(1,560)	1,674
COMPREHENSIVE INCOME	594,672	522,242	483,308
Less: Comprehensive income attributable to noncontrolling interests	19,493	19,493	19,493
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$575,179	$502,749	$463,815

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

Table of Contents

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

	December 31, 2018	2017
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Notes 1, 6 and 9)		
Plant in service and held for future use	$18,733,142	$17,654,078
Accumulated depreciation and amortization	(6,362,771)	(6,041,965)
Net	12,370,371	11,612,113
Construction work in progress	1,170,062	1,266,636
Palo Verde sale leaseback, net of accumulated depreciation of $245,275 and $241,405 (Note 18)	105,775	109,645
Intangible assets, net of accumulated amortization of $590,069 and $581,135	262,746	257,028
Nuclear fuel, net of accumulated amortization of $137,850 and $144,070	120,217	117,408
Total property, plant and equipment	14,029,171	13,362,830
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Notes 13 and 19)	851,134	871,000
Other special use funds (Notes 13 and 19)	236,101	30,358
Other assets	40,817	36,796
Total investments and other assets	1,128,052	938,154
CURRENT ASSETS		
Cash and cash equivalents	5,707	13,851
Customer and other receivables	257,654	292,791
Accrued unbilled revenues	137,170	112,434
Allowance for doubtful accounts	(4,069)	(2,513)
Materials and supplies (at average cost)	269,065	262,630
Fossil fuel (at average cost)	25,029	25,258
Assets from risk management activities (Note 16)	1,113	1,931
Deferred fuel and purchased power regulatory asset (Note 3)	37,164	75,637
Other regulatory assets (Note 3)	129,738	172,451
Other current assets	35,111	41,055
Total current assets	893,682	995,525
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3, and 4)	1,342,941	1,202,302
Assets for other postretirement benefits (Note 7)	43,212	265,139
Other	128,265	129,801
Total deferred debits	1,514,418	1,597,242
TOTAL ASSETS	$17,565,323	$16,893,751

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

Table of Contents

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

	December 31, 2018	2017
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$178,162	$178,162
Additional paid-in capital	2,721,696	2,571,696
Retained earnings	2,788,256	2,533,954
Accumulated other comprehensive loss (Note 21)	(27,107)	(26,983)
Total shareholder equity	5,661,007	5,256,829
Noncontrolling interests (Note 18)	125,790	129,040
Total equity	5,786,797	5,385,869
Long-term debt less current maturities (Note 6)	4,189,436	4,491,292
Total capitalization	9,976,233	9,877,161
CURRENT LIABILITIES		
Current maturities of long-term debt (Note 6)	500,000	82,000
Accounts payable	266,277	247,852
Accrued taxes	176,357	157,349
Accrued interest	60,228	55,533
Common dividends payable	82,700	77,700
Customer deposits	91,174	70,388
Liabilities from risk management activities (Note 16)	35,506	59,252
Liabilities for asset retirements (Note 11)	19,842	4,192
Regulatory liabilities (Note 3)	165,876	100,086
Other current liabilities	178,137	243,922
Total current liabilities	1,576,097	1,098,274
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,812,664	1,742,485
Regulatory liabilities (Notes 1, 3, and 4)	2,325,976	2,452,536
Liabilities for asset retirements (Note 11)	706,703	666,527
Liabilities for pension benefits (Note 7)	425,404	306,542
Liabilities from risk management activities (Note 16)	24,531	37,170
Customer advances	137,153	113,996
Coal mine reclamation	212,785	215,830
Deferred investment tax credit	200,405	205,575
Unrecognized tax benefits (Note 4)	41,861	43,876
Other	125,511	133,779
Total deferred credits and other	6,012,993	5,918,316
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$17,565,323	$16,893,751

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

Table of Contents

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

	Year Ended December 31,		
	2018	**2017**	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$589,758	$523,802	$481,634
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization including nuclear fuel	649,295	608,935	564,091
Deferred fuel and purchased power	(78,277)	(48,405)	(60,303)
Deferred fuel and purchased power amortization	116,750	(14,767)	38,152
Allowance for equity funds used during construction	(52,319)	(47,011)	(42,140)
Deferred income taxes	59,927	249,465	221,167
Deferred investment tax credit	(5,170)	(4,587)	23,082
Change in derivative instruments fair value	—	(373)	(403)
Changes in current assets and liabilities:			
Customer and other receivables	35,406	(68,040)	(1,601)
Accrued unbilled revenues	(24,736)	(4,485)	(11,709)
Materials, supplies and fossil fuel	(6,206)	(6,503)	(1,454)
Income tax receivable	—	11,174	(14,567)
Other current assets	31,707	(6,775)	(21,640)
Accounts payable	(15,608)	(26,561)	(67,543)
Accrued taxes	19,008	26,773	(13,912)
Other current liabilities	25,070	27,912	5,097
Change in margin and collateral accounts — assets	143	(300)	673
Change in margin and collateral accounts — liabilities	(2,211)	(533)	17,735
Change in unrecognized tax benefits	(1,235)	5,891	1,628
Change in long-term regulatory liabilities	(109,284)	45,764	14,682
Change in other long-term assets	77,952	(78,540)	(45,866)
Change in other long-term liabilities	(55,169)	(31,106)	(76,855)
Net cash flow provided by operating activities	1,254,801	1,161,730	1,009,948
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(1,169,061)	(1,381,930)	(1,248,010)
Contributions in aid of construction	27,716	23,708	64,296
Allowance for borrowed funds used during construction	(25,180)	(22,112)	(19,481)
Proceeds from nuclear decommissioning trust sales and other special use funds	653,033	542,246	633,410
Investment in nuclear decommissioning trust and other special use funds	(672,165)	(544,527)	(635,691)
Other	(1,789)	(18,538)	(13,865)
Net cash flow used for investing activities	(1,187,446)	(1,401,153)	(1,219,341)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	295,245	549,478	693,151
Repayment of long-term debt	(182,000)	—	(370,430)
Short-term borrowings and (repayments) — net	—	(135,500)	135,500
Short-term debt borrowings under revolving credit facility	25,000	—	—
Short-term debt repayments under revolving credit facility	(25,000)	—	—
Dividends paid on common stock	(316,000)	(296,800)	(281,300)
Equity infusion from Pinnacle West	150,000	150,000	42,000
Noncontrolling interests	(22,744)	(22,744)	(22,744)

Net cash flow provided by (used for) financing activities	(75,499)	244,434	196,177
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(8,144)	5,011	(13,216)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	13,851	8,840	22,056
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 5,707	$ 13,851	$ 8,840
Supplemental disclosure of cash flow information:			
Cash paid (received) during the year for:			
Income taxes, net of refunds	$ 77,942	$ (14,098)	$ 26,864
Interest, net of amounts capitalized	196,419	184,210	181,809
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$ 132,620	$ 130,057	$ 114,874
Dividends declared but not paid	82,700	77,700	72,900

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

Table of Contents

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, 2015	71,264,947	$178,162	$2,379,696	$2,148,493	$ (27,097)	$ 135,540	$4,814,794
Equity infusion from Pinnacle West		—	42,000	—	—	—	42,000
Net income		—	—	462,141	—	19,493	481,634
Other comprehensive income		—	—	—	1,674	—	1,674
Dividends on common stock		—	—	(284,800)	—	—	(284,800)
Stock compensation cumulative effect adjustments (a)		—	—	5,411	—	—	5,411
Net capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2016	71,264,947	178,162	2,421,696	2,331,245	(25,423)	132,290	5,037,970
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	504,309	—	19,493	523,802
Other comprehensive loss		—	—	—	(1,560)	—	(1,560)
Dividends on common stock		—	—	(301,600)	—	—	(301,600)
Net capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2017	71,264,947	178,162	2,571,696	2,533,954	(26,983)	129,040	5,385,869
Equity infusion from Pinnacle West		—	150,000	—	—	—	150,000
Net income		—	—	570,265	—	19,493	589,758
Other comprehensive income		—	—	—	4,914	—	4,914
Dividends on common stock		—	—	(321,001)	—	—	(321,001)
Reclassifications of income tax effects related to new tax reform (See Note 2)		—	—	5,038	(5,038)	—	—
Net capital activities by noncontrolling interests		—	—	—	—	(22,743)	(22,743)
Balance, December 31, 2018	71,264,947	$178,162	$2,721,696	$2,788,256	$ (27,107)	$ 125,790	$5,786,797

(a) During 2016, we adopted new stock-based compensation accounting guidance.

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

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, BCE and 4CA. 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. 4CA is a subsidiary that was formed in 2016 as a result of the purchase of El Paso's 7% interest in Four Corners. See Note 10 for more information on 4CA matters.

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, El Dorado, BCE and 4CA. 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.

These consolidated financial statements and notes have been prepared consistently, with the exception of the reclassification of certain prior year amounts on our Consolidated Statements of Income and APS's Consolidated Statements of Income. Beginning in the quarter ended March 31, 2018, APS changed the format of presentation of its Consolidated Statements of Income from a utility ratemaking format to a commercial format. Minor changes were made in the description of certain income statement line items and the amounts presented in the comparable prior period also changed by immaterial amounts due to the change from a utility to a non-utility format and also from the adoption of the new accounting guidance for net periodic pension cost and net periodic postretirement benefit cost. In addition, the prior year amounts were reclassified to conform to the current year presentation for the other special use funds in the investment and other assets section on the Consolidated Balance Sheets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America ("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 amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred and are refundable to customers.

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

See Note 3 for additional information.

Electric Revenues

We derive electric revenues primarily from sales of electricity to our regulated Native Load customers. Revenues related to the sale of electricity are generally recognized 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. We obtain customers' meter data on a systematic basis throughout the month, and generally bill customers within a month from when service was provided. Customers are generally required to pay for services within 15 days of when the services are billed. 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.

On January 1, 2018, we adopted new revenue guidance ASU 2014-09, Revenue from contracts with customers, accordingly our 2018 electric revenues primarily consist of activities that now are classified as revenues from contracts with customers. Our electric revenues generally represent a single performance obligation delivered over time. We have elected to apply the invoice practical expedient and, as such, we recognize revenue based on the amount to which we have a right to invoice for services performed. See Note 2.

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 electricity are netted against other contracts to sell electricity. This is called a "book-out" and usually occurs for contracts that have the same terms (quantities, delivery points and delivery periods) and for which

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

power does not flow. We net these book-outs, which reduces both wholesale 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.

See Notes 2 and 20 for additional information.

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.

Pinnacle West’s property, plant and equipment included in the December 31, 2018 and 2017 Consolidated Balance Sheets is composed of the following (dollars in thousands):

Property, Plant and Equipment:	**2018**	**2017**
Generation	$8,285,514	$7,963,998
Transmission	3,033,579	2,836,578
Distribution	6,378,345	6,025,856

General plant	1,039,190	971,629
Plant in service and held for future use	18,736,628	17,798,061
Accumulated depreciation and amortization	(6,366,014)	(6,128,535)
Net	12,370,614	11,669,526
Construction work in progress	1,170,062	1,291,498
Palo Verde sale leaseback, net of accumulated depreciation	105,775	109,645
Intangible assets, net of accumulated amortization	262,902	257,189
Nuclear fuel, net of accumulated amortization	120,217	117,408
Total property, plant and equipment	$14,029,570	$13,445,266

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 excess of the amount that has been recovered in regulated rates over the amount calculated in accordance with guidance on accounting for asset retirement obligations. APS believes it is probable it will recover in regulated rates, the costs calculated in accordance with this accounting guidance.

We record depreciation and amortization 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, 2018 were as follows:

•Fossil plant ~~17~~ years;
•Nuclear plant ~~23~~ years;
•Other generation ~~19~~ years;
•Transmission ~~39~~ years;
•Distribution ~~34~~ years; and
•General plant ~~6~~ years.

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense was $486 million in 2018, $453 million in 2017, and $422 million in 2016. For the years 2016 through 2018, the depreciation rates ranged from a low of 0.18% to a high of 19.67%. The weighted-average depreciation rate was 2.81% in 2018, 2.80% in 2017, and 2.66% in 2016.

Asset Retirement Obligations

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

See Note 11 for further information on Asset Retirement Obligations.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 7.03% for 2018, 6.68% for 2017, and 7.17% for 2016. 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 apply recurring fair value measurements to cash equivalents, derivative instruments, investments held in the nuclear decommissioning trust and other special use funds. On an annual basis, we apply fair value measurements to plan assets held in our retirement and other benefits plans. Due to the short-term nature of 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.

See Note 13 for additional information about fair value measurements.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 Notes 2 and 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 another 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. On January 1, 2018, we adopted new accounting guidance ASU 2017-07, Compensation-Retirement Benefits: Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost. See Note 2 for additional discussion.

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 reduced the fee to zero. In accordance with a settlement agreement with the DOE in August 2014, we will now accrue a receivable for incurred

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

claims and an offsetting regulatory liability through the settlement period ending December of 2019. 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 and are based on currently enacted tax rates. 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. On January 1, 2018, we adopted new guidance ASU 2018-02, Income Statement-Reporting Comprehensive Income: Reclassification of certain tax effects from accumulated other comprehensive income. See Note 4 for additional discussion.

Cash and Cash Equivalents

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

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

	Year ended December 31,		
	2018	**2017**	**2016**
Cash paid during the period for:			
Income taxes, net of refunds	$21,173	$2,186	$9,956
Interest, net of amounts capitalized	208,479	189,288	184,462
Significant non-cash investing and financing activities:			
Accrued capital expenditures	$132,620	$130,404	$114,855
Dividends declared but not paid	82,675	77,667	72,926
Sale of 4CA 7% interest in Four Corners	68,907	—	—

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 $68 million in 2018, $72 million in 2017, and $58 million in 2016. Estimated amortization expense on existing intangible assets over the next five years is $58 million in 2019, $47 million in 2020, $34 million in 2021, $25 million in 2022, and $22 million in 2023. At December 31, 2018, the weighted-average remaining amortization period for intangible assets was 8 years.

Investments

El Dorado holds investments in both debt and equity securities. Investments in debt securities are generally accounted for as held-to-maturity and investments in equity securities are accounted for using either

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

the equity method (if significant influence) or the measurement alternative for investments without readily determinable fair values (if less than 20% ownership and no significant influence).

Our investments in the nuclear decommissioning trust fund, coal reclamation escrow and active union employee medical account, are accounted for in accordance with guidance on accounting for investments in debt and equity securities. See Notes 13 and 19 for more information on these investments.

On January 1, 2018, we adopted new accounting guidance ASU 2016-01, Financial Instruments: Recognition and measurement. See Note 2.

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, 2018, 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

Standards Adopted in 2018

ASU 2014-09, Revenue from Contracts with Customers

In May 2014, a new revenue recognition accounting standard was issued. This standard 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. Since the issuance of the new revenue standard, additional guidance was issued to clarify certain aspects of the new revenue standard, including principal versus agent considerations, identifying performance obligations, and other narrow scope improvements. The new revenue standard, and related amendments, became effective for us on January 1, 2018. The standard 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 adopted this standard and related amendments on January 1, 2018 using the modified retrospective transition approach. The adoption of the new revenue guidance resulted in expanded disclosures, but otherwise did not have a material impact on our financial statements. See Note 20.

ASU 2016-01, Financial Instruments: Recognition and Measurement

In January 2016, a new accounting standard was issued relating to the recognition and measurement of financial instruments. The new guidance requires 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 standard was effective for us on January 1, 2018. The standard required modified retrospective application, with the exception of certain aspects of the standard that required prospective

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

application. We adopted this standard on January 1, 2018, using primarily a retrospective approach. Due to regulatory accounting treatment, the adoption of this standard did not have a material impact on our financial statements. See Notes 13 and 19 for disclosures relating to our investments in debt and equity securities.

ASU 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

In August 2016, a new accounting standard was issued that clarifies how entities should present certain specific cash flow activities on the statement of cash flows. The guidance is intended to eliminate diversity in practice in how entities classify these specific activities between cash flows from operating activities, investing activities and financing activities. The specific activities addressed include debt prepayments and extinguishment costs, proceeds from the settlement of insurance claims, proceeds from corporate-owned life insurance policies, and other activities. The standard also addresses how entities should apply the predominance principle when a transaction includes separately identifiable cash flows. The new standard was effective for us, and was adopted on January 1, 2018, using a retrospective transition method. The adoption of this guidance did not have a significant impact on our financial statements, as either our statement of cash flow presentation is consistent with the new prescribed guidance or we do not have significant activities relating to the specific transactions that are addressed by the new standard.

ASU 2016-18, Statement of Cash Flows: Restricted Cash

In November 2016, a new accounting standard was issued that clarifies how restricted cash and restricted cash equivalents should be presented on the statement of cash flows. The new guidance requires entities to include restricted cash and restricted cash equivalents as a component of the beginning and ending cash and cash equivalent balances on the statement of cash flows. The new standard is effective for us, and was adopted on January 1, 2018, using a retrospective transition method. The adoption of this guidance did not impact our financial statements, as our holdings and activities designated as restricted cash and restricted cash equivalents at transition and in prior periods are insignificant.

ASU 2017-01, Business Combinations: Clarifying the Definition of a Business

In January 2017, a new accounting standard was issued that clarifies the definition of a business. This standard is intended to assist entities with evaluating whether a transaction should be accounted for as an acquisition (or disposal) of assets or a business. The definition of a business affects many areas of accounting, including acquisitions, disposals, goodwill, and consolidation. The new standard was effective for us and was adopted on January 1, 2018 using a prospective transition approach. This standard did not have an impact on our financial statements on the date of adoption.

ASU 2017-05, Other Income: Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets

In February 2017, a new accounting standard was issued that intended to clarify the scope of accounting guidance pertaining to gains and losses from the derecognition of nonfinancial assets, and to add guidance for partial sales of nonfinancial assets. The new standard was effective for us, and was adopted on January 1, 2018, using a modified retrospective transition approach. This standard did not have a significant impact on our financial statements on the date of adoption. On July 3, 2018, 4CA sold its 7% interest in Four Corners. The sale transaction was accounted for in accordance with the guidance in ASU 2017-05, see Note 10.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

ASU 2017-07, Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, a new accounting standard was issued that modifies how plan sponsors present net periodic pension cost and net periodic postretirement benefit cost (net benefit costs). The presentation changes require net benefit costs to be disaggregated on the income statement by the various components that comprise these costs. Specifically, only the service cost component is eligible for presentation as an operating income item, and all other cost components are now presented as non-operating items. This presentation change was applied retrospectively. Furthermore, the new standard allows only the service cost component to be eligible for capitalization. The change in capitalization requirements was applied prospectively. The new guidance was effective for us on January 1, 2018.

We adopted this new accounting standard on January 1, 2018. As a result of adopting this standard we have presented the non-service cost components of net benefits costs in other income instead of operating income. Prior year non-service cost components have also been reclassified to conform to this new presentation. We elected to apply the practical expedient guidance. As such, prior period costs have been estimated based on amounts previously disclosed in our pension and other postretirement benefit plan notes. The changes impacting capitalization have been adopted prospectively. As such, upon adoption, we are no longer capitalizing a portion of the non-service cost components of net benefit costs.

In 2018 the non-service credit components are a reduction to total benefit costs. Excluding non-service credits from eligible capitalization costs resulted in the capitalization of an additional $15 million of net benefit costs, with a corresponding increase to pretax income for the year. See Note 7 for additional information related to our pension plans and other postretirement benefits.

ASU 2018-02, Income Statement-Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

In February 2018, new accounting guidance was issued that allows entities an optional election to reclassify the income tax effects of the Tax Act on items within accumulated other comprehensive income to retained earnings. Amounts eligible for reclassification must relate to the effects from the Tax Act remaining in accumulated other comprehensive income. The new guidance also requires expanded disclosures. This guidance is effective for us on January 1, 2019 with early application permitted. The guidance should be applied either in the period of adoption or retrospectively to each period in which the effect of the Tax Act was recognized.

We early adopted this guidance in the quarter ended March 31, 2018, and we have elected to reclassify the income tax effects of the Tax Act related to other comprehensive income to retained earnings. As of December 31, 2018, on a consolidated basis our accumulated other comprehensive income decreased $9 million, and APS's accumulated other comprehensive income decreased $5 million, as a result of adopting this guidance. Amounts were reclassified from accumulated other comprehensive income to retained earnings, and related to tax rate changes. The adoption of this guidance did not impact our income from continuing operations. See Note 4 for additional discussion of the Tax Act.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Standards Adopted in 2019

ASU 2016-02, Leases

In February 2016, a new lease accounting standard was issued. This new standard supersedes the existing lease accounting model, and modifies both lessee and lessor accounting. The new standard requires a lessee to reflect most operating lease arrangements on the balance sheet by recording a right-of-use asset and a lease liability that is initially measured at the present value of lease payments. Among other changes, the new standard also modifies the definition of a lease, and requires expanded lease disclosures. Since the issuance of the new lease standard, additional lease related guidance has been issued relating to land easements and how entities may elect to account for these arrangements at transition, among other items. The new lease standard and related amendments were effective for us on January 1, 2019, with early application permitted. The standard must be adopted using a modified retrospective approach with a cumulative-effect adjustment to the opening balance of retained earnings determined at either the date of adoption, or the earliest period presented in the financial statements. The standard includes various optional practical expedients provided to facilitate transition.

We adopted this standard, and related amendments, on January 1, 2019. We elected the transition method that allows us to apply the guidance on the date of adoption, January 1, 2019, and will not retrospectively adjust prior periods. We also elected certain transition practical expedients that allow us to not reassess (a) whether any expired or existing contracts are or contain leases, (b) the lease classification for any expired or existing leases and (c) initial direct costs for any existing leases. These practical expedients apply to leases that commenced prior to January 1, 2019. Furthermore, we elected the practical expedient transition provisions relating to the treatment of existing land easements.

On January 1, 2019 the adoption of this new accounting standard resulted in the recognition on our Consolidated Balance Sheets of approximately $194 million of right-of-use lease assets and $119 million of lease liabilities relating to our operating lease arrangements. The right-of-use lease assets include $85 million of prepaid lease costs that have been reclassified from other deferred debits, and $10 million of deferred lease costs that have been reclassified from other current liabilities. In addition to these balance sheet impacts the adoption of the guidance will also result in expanded lease related disclosures in our 2019 financial statements.

ASU 2017-12, Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities

In August 2017, a new accounting standard was issued that modifies hedge accounting guidance with the intent of simplifying the application of hedge accounting. The new standard became effective for us on January 1, 2019, with early application permitted. At transition, the guidance requires the changes to be applied to hedging relationships existing on the date of adoption, with the effect of adoption reflected as of the beginning of the fiscal year of adoption using a cumulative effect adjustment approach. The presentation and disclosure changes may be applied prospectively. We adopted this standard on January 1, 2019 and because we are not currently applying hedge accounting, the adoption of the standard did not impact our financial statements.

Standards Pending Adoption

ASU 2016-13, Financial Instruments: Measurement of Credit Losses

In June 2016, a new accounting standard was issued that amends the measurement of credit losses on certain financial instruments. The new standard will require entities to use a current expected credit loss model

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

to measure impairment of certain investments in debt securities, trade accounts receivables, and other financial instruments. The new standard is effective for us on January 1, 2020 and must be adopted using a modified retrospective approach for certain aspects of the standard, and a prospective approach for other aspects of the standard. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

ASU 2018-15, Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract

In August 2018, a new accounting standard was issued that clarifies how customers in a cloud computing service arrangement should account for implementation costs associated with the arrangement. To determine which implementation costs should be capitalized, the new guidance aligns the accounting with existing guidance pertaining to internal-use software. As a result of this new standard, certain cloud computing service arrangement implementation costs will now be subject to capitalization and amortized on a straight-line basis over the cloud computing service arrangement term. The new standard is effective for us on January 1, 2020, with early application permitted, and may be applied using either a retrospective or prospective transition approach. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

3. Regulatory Matters

Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates of $165.9 million. This amount excluded amounts that were then collected on customer bills through adjustor mechanisms. The application requested that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have had an incremental effect on average customer bills. The average annual customer bill impact of APS's request was an increase of 5.74% (the average annual bill impact for a typical APS residential customer was 7.96%).

On March 27, 2017, a majority of the stakeholders in the general retail rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations signed a settlement agreement (the "2017 Settlement

Agreement") and filed it with the ACC. The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61.0 million due to changes in depreciation schedules. The average annual customer bill impact under the 2017 Settlement Agreement was calculated as an increase of 3.28% (the average annual bill impact for a typical APS residential customer was calculated as 4.54%).

Other key provisions of the agreement include the following:

- an agreement by APS not to file another general retail rate case application before June 1, 2019;
- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS's next general retail rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;

116

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general retail rate case related to its share of the construction costs associated with installing selective catalytic reduction ("SCR") equipment at Four Corners;
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the PSA to include certain environmental chemical costs and third-party battery storage costs;
- a new AZ Sun II program (now known as APS Solar Communities) for utility-owned solar DG with the purpose of expanding access to rooftop solar for low and moderate income Arizonans, recoverable through the RES, to be no less than $10 million per year, and not more than $15 million per year;
- an increase to the per kWh cap for the environmental improvement surcharge from $0.00016 to $0.00050 and the addition of a balancing account;
- rate design changes, including:
  - a change in the on-peak time of use period from noon - 7 p.m. to 3 p.m. - 8 p.m. Monday through Friday, excluding holidays;
  - non-grandfathered DG customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
  - a Resource Comparison Proxy (“RCP”) for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

Through a separate agreement, APS, industry representatives, and solar advocates committed to stand by the 2017 Settlement Agreement and refrain from seeking to undermine it through ballot initiatives, legislation or advocacy at the ACC.

On August 15, 2017, the ACC approved (by a vote of 4-1), the 2017 Settlement Agreement without material modifications. On August 18, 2017, the ACC issued a final written Opinion and Order reflecting its decision in APS’s general retail rate case (the "2017 Rate Case Decision"), which is subject to requests for rehearing and potential appeal. The new rates went into effect on August 19, 2017.

On October 17, 2017, Warren Woodward (an intervener in APS's general retail rate case) filed a Notice of Appeal in the Arizona Court of Appeals, Division One. The notice raises a single issue related to the application of certain rate schedules to new APS residential customers after May 1, 2018. Mr. Woodward filed a second notice of appeal on November 13, 2017 challenging APS's $5 per month automated metering infrastructure opt-out program. Mr. Woodward's two appeals have been consolidated, and APS requested and was granted intervention. Mr. Woodward filed his opening brief on March 28, 2018. The ACC and APS filed responsive briefs on June 21, 2018. The Arizona Court of Appeals issued a Memorandum Decision on December 11, 2018 affirming the ACC decisions challenged by Mr. Woodward. Mr. Woodward filed a petition for review with the Arizona Supreme Court on January 9, 2019. Review by the Arizona Supreme Court is discretionary. APS cannot predict the outcome of this consolidated appeal but does not believe it will have a material impact on our financial position, results of operations or cash flows.

On January 3, 2018, an APS customer filed a petition with the ACC that was determined by the ACC Staff to be a complaint filed pursuant to Arizona Revised Statute §40-246 (the "Complaint") and not a request for rehearing. Arizona Revised Statute §40-246 requires the ACC to hold a hearing regarding any complaint alleging that a public service corporation is in violation of any commission order or that the rates being charged are not just and reasonable if the complaint is signed by at least twenty-five customers of the public

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

service corporation. The Complaint alleged that APS is “in violation of commission order” [sic]. On February 13, 2018, the complainant filed an amended Complaint alleging that the rates and charges in the 2017 Rate Case Decision are not just and reasonable. The complainant requested that the ACC hold a hearing on the amended Complaint to determine if the average bill impact on residential customers of the rates and charges approved in the 2017 Rate Case Decision is greater than 4.54% (the average annual bill impact for a typical APS residential customer estimated by APS,) and, if so, what effect the alleged greater bill impact has on APS's revenues and the overall reasonableness and justness of APS's rates and charges, in order to determine if there is sufficient evidence to warrant a full-scale rate hearing. The ACC held a hearing on this matter beginning in September 2018 and the hearing was concluded on October 1, 2018. Post-hearing briefing was concluded on December 14, 2018. APS expects a recommended opinion and order from the judge within the first quarter of 2019. APS cannot predict the outcome of this matter.

On December 24, 2018, certain ACC Commissioners filed a letter stating that because the ACC had received a substantial number of complaints that the rate increase authorized by the 2017 Rate Case Decision was much more than anticipated, they believe there is a possibility that APS is earning more than was authorized by the 2017 Rate Case Decision. Accordingly, the ACC Commissioners requested the ACC Staff to perform a rate review of APS using calendar year 2018 as a test year and file a report by May 3, 2019. The ACC Commissioners also asked the ACC Staff to evaluate APS’s efforts to educate its customers regarding the new rates approved in the 2017 Rate Case Decision. On January 9, 2019, the ACC Commissioners voted to open a docket for this matter. APS does not believe that the rate review will have a material impact on our financial position, results of operations or cash flows. However, depending upon the results of the rate review, the ACC may take further actions, including potentially attempting to reopen the 2017 Rate Case Decision. APS cannot predict the outcome of this matter.

Prior Rate Case Filing with the Arizona Corporation Commission

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. On January 6, 2012, APS and other parties to the general retail rate case entered into an agreement (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.

Cost Recovery Mechanisms

APS has received regulatory decisions that allow for more timely recovery of certain costs outside of a general retail rate case 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The costs for this program have been included in APS's rate base as part of the 2017 Rate Case Decision.

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS’s budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. On April 7, 2017, APS filed an amended 2017 RES Implementation Plan and updated budget request which included the revenue neutral transfer of specific revenue requirements into base rates in accordance with the 2017 Settlement Agreement. On August 15, 2017, the ACC approved the 2017 RES Implementation Plan.

On June 30, 2017, APS filed its 2018 RES Implementation Plan and proposed a budget of approximately $90 million. APS’s budget request supports existing approved projects and commitments and includes the anticipated transfer of specific revenue requirements into base rates in accordance with the 2017 Settlement Agreement and also requests a permanent waiver of the residential distributed energy requirement for 2018 contained in the RES rules. APS's 2018 RES budget request is lower than the 2017 RES budget due in part to a certain portion of the RES being collected by APS in base rates rather than through the RES adjustor.

On November 20, 2017, APS filed an updated 2018 RES budget to include budget adjustments for APS Solar Communities (formerly known as AZ Sun II), which was approved as part of the 2017 Rate Case Decision. APS Solar Communities is a 3-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems for low to moderate income residential homes, buildings of non-profit entities, Title I schools and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES. On June 12, 2018, the ACC approved the 2018 RES Implementation Plan.

On June 29, 2018, APS filed its 2019 RES Implementation Plan and proposed a budget of approximately $89.9 million. APS's budget request supports existing approved projects and commitments and requests a permanent waiver of the residential distributed energy requirement for 2019 contained in the RES rules. The ACC has not yet ruled on the 2019 RES Implementation Plan.

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. On January 30, 2018, ACC Commissioner Tobin proposed a plan in this proceeding which would broaden the RES to include a series of energy policies tied to clean energy sources (the "Energy Modernization Plan"). The Energy Modernization Plan includes replacing the current RES standard with a new standard called the Clean Resource Energy Standard and Tariff ("CREST"), which incorporates the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

proposals in the Energy Modernization Plan. A set of draft CREST rules for the ACC’s consideration was issued by Commissioner Tobin’s office on July 5, 2018. See "Energy Modernization Plan" below for more information on CREST.

Demand Side Management Adjustor Charge. The ACC EES requires APS to submit a Demand Side Management Implementation Plan ("DSM Plan") annually for review by and approval of the ACC. 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 ruled that verified energy savings from APS's resource savings projects could be counted toward compliance with the EES; however, the ACC ruled that APS was not allowed to count savings from systems savings projects toward determination of the achievement of performance incentives, nor may APS include savings from conservation voltage reduction in the calculation of its LFCR mechanism.

On June 1, 2016, APS filed its 2017 DSM Plan, in which APS proposed programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Plan was $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Plan that incorporated the proposed Residential Demand Response, Energy Storage and Load Management Program and requested that the budget be increased to $66.6 million. On August 15, 2017, the ACC approved the amended 2017 DSM Plan.

On September 1, 2017, APS filed its 2018 DSM Plan, which proposes modifications to the demand side management portfolio to better meet system and customer needs by focusing on peak demand reductions, storage, load shifting and demand response programs in addition to traditional energy savings measures. The 2018 DSM Plan seeks a reduced requested budget of $52.6 million and requests a waiver of the EES for 2018. On November 14, 2017, APS filed an amended 2018 DSM Plan, which revised the allocations between budget items to address customer participation levels, but kept the overall budget at $52.6 million. The ACC has not yet ruled on the APS 2018 amended DSM Plan.

On December 31, 2018, APS filed its 2019 DSM Plan, which requests a budget of $34.1 million and continues APS's focus on DSM strategies such as peak demand reduction, load shifting, storage and electrification strategies. The ACC has not yet ruled on the APS 2019

DSM Plan.

Power Supply Adjustor 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 or refunded through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "Transition Component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and

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

The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2018 and 2017 (dollars in thousands):

	Twelve Months Ended December 31,	
	2018	2017
Beginning balance	$ 75,637	$ 12,465
Deferred fuel and purchased power costs — current period	78,277	48,405
Amounts refunded/(charged) to customers	(116,750)	14,767
Ending balance	$ 37,164	$ 75,637

The PSA rate for the PSA year beginning February 1, 2017 was $(0.001348) per kWh, as compared to $0.001678 per kWh for the prior year. This rate was comprised of a forward component of $(0.001027) per kWh and a historical component of $(0.000321) per kWh. On August 19, 2017, the PSA rate was revised to $0.000555 per kWh as part of the 2017 Rate Case Decision. This new rate was comprised of a forward component of $0.000876 per kWh and a historical component of $(0.000321) per kWh.

The PSA rate for the PSA year beginning February 1, 2018 is $0.004555 per kWh, consisting of a forward component of $0.002009 per kWh and a historical component of $0.002546 per kWh. This represented a $0.004 per kWh increase over the August 19, 2017 PSA, the maximum permitted under the Plan of Administration for the PSA. This left $16.4 million of 2017 fuel and purchased power costs above this annual cap. These costs rolled over until the following year and were reflected in the 2019 reset of the PSA.

On November 30, 2018, APS filed its PSA rate for the PSA year beginning February 1, 2019. That rate was $0.001658 per kWh and consisted of a forward component of $0.000536 per kWh and a historical component of $0.001122 per kWh. The 2019 PSA rate is a

$0.002897 per kWh decrease compared to 2018. These rates went into effect as filed on February 1, 2019.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2017, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $35.1 million for the twelve-month period beginning June 1, 2017 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, 2017. Effective June 1, 2018, APS's annual wholesale transmission rates for all users of its transmission system decreased by approximately $22.7 million for the twelve-month period beginning June 1, 2018 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, 2018.

On January 31, 2017, APS made a filing with FERC to reduce the Post-Employment Benefits Other than Pension expense reflected in its FERC transmission formula rate calculation to recognize certain savings resulting from plan design changes to the other postretirement benefit plans. A transmission customer intervened and protested certain aspects of APS’s filing. FERC initiated a proceeding under Section 206 of the Federal Power Act to evaluate the justness and reasonableness of the revised formula rate filing APS proposed. APS entered into a settlement agreement with the intervening transmission customer, which was filed with FERC for approval on September 26, 2017. FERC approved the settlement agreement without modification or condition on December 21, 2017.

On March 7, 2018, APS made a filing to make modifications to its annual transmission formula to provide transmission customers the benefit of the reduced federal corporate income tax rate resulting from the Tax Act beginning in its 2018 annual transmission formula rate update filing. These modifications were approved by FERC on May 22, 2018 and reduced APS's transmission rates compared to the rate that would have gone into effect absent these changes.

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 DG such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were first 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. These amounts were revised in the 2017 Settlement Agreement to 2.5 cents for both lost residential and non-residential kWh. 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. DG sales losses are determined from the metered output from the DG units.

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). The ACC approved the 2016 annual LFCR effective beginning in May 2016. APS filed its 2017 LFCR adjustment on January 13, 2017 requesting an LFCR adjustment of

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

$63.7 million (a $17.3 million per year increase over 2016 levels). On April 5, 2017, the ACC approved the 2017 annual LFCR adjustment as filed, effective with the first billing cycle of April 2017. On February 15, 2018, APS filed its 2018 annual LFCR Adjustment, requesting that effective May 1, 2018, the LFCR be adjusted to $60.7 million (a $3 million per year decrease from 2017 levels). On February 6, 2019, the ACC approved the 2018 annual LFCR adjustment to become effective March 1, 2019. On February 15, 2019, APS filed its 2019 annual LFCR adjustment, requesting that effective May 1, 2019, the annual LFCR recovery amount be reduced to $36.2 million (a $24.5 million decrease from previous levels). Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, the delay in implementation does not have an adverse effect on APS.

Tax Expense Adjustor Mechanism and FERC Tax Filing. As part of the 2017 Settlement Agreement, the parties agreed to a rate adjustment mechanism to address potential federal income tax reform and enable the pass-through of certain income tax effects to customers. On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws including a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018.

On January 8, 2018, APS filed an application with the ACC requesting that the TEAM be implemented in two steps. The first addresses the change in the marginal federal tax rate from 35% to 21% resulting from the Tax Act and, if approved, would reduce rates by $119.1 million annually through an equal cents per kWh credit. APS asked that this decrease become effective February 1, 2018. On February 22, 2018, the ACC approved the reduction of rates by $119.1 million for the remainder of 2018 through an equal cents per kWh credit applied to all but a small subset of customers who are taking service under specially-approved tariffs. The rate reduction was effective for the first billing cycle in March 2018.

The impact of the TEAM, over time, is expected to be earnings neutral. However, on a quarterly basis, there is a difference between the timing and amount of the income tax benefit and the reduction in revenues refunded through the TEAM related to the lower federal income tax rate. The amount of the benefit of the lower federal income tax rate is based on quarterly pre-tax results, while the reduction in revenues from the prior year due to lower customer rates through the TEAM is based on a per kWh sales credit which follows our seasonal kWh sales pattern and is not impacted by earnings of the Company.

On August 13, 2018, APS filed a second request with the ACC to return an additional $86.5 million in tax savings to customers. This second request addresses amortization of non-depreciation related excess deferred taxes previously collected from customers. The ACC has not yet approved this request.

Additionally, as part of this second request, APS informed the ACC of its intent to file a third future request to address the amortization of depreciation related excess deferred taxes, as the Company is currently in the process of seeking IRS guidance regarding the amortization method and period applicable to these depreciation related excess deferred taxes.

The TEAM expressly applies to APS's retail rates with the exception of a small subset of customers taking service under specially-approved tariffs noted above. As discussed under "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters" above, FERC issued an order on May 22, 2018 authorizing APS to provide for the cost reductions resulting from the income tax changes in its wholesale transmission rates.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Net Metering

In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of DG to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, the Administrative Law Judge issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended opinion and order by the Administrative Law Judge. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC's action, effective with APS's 2017 Rate Case Decision, the net metering tariff that governs payments for energy exported to the grid from residential rooftop solar systems was replaced by a more formula-driven approach that utilizes inputs from historical wholesale solar power until an avoided cost methodology is developed by the ACC.

As amended, the decision provides that payments by utilities for energy exported to the grid from DG solar facilities will be determined using a RCP methodology, a method that is based on the most recent five-year rolling average price that APS pays for utility-scale solar projects, while a forecasted avoided cost methodology is being developed. The price established by this RCP method will be updated annually (between general retail rate cases) but will not be decreased by more than 10% per year. Once the avoided cost methodology is developed, the ACC will determine in APS's subsequent rate cases which method (or a combination of methods) is appropriate to determine the actual price to be paid by APS for exported distributed energy.

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to September 1, 2017, the date new rates were effective based on APS's 2017 Rate Case Decision, will be grandfathered for a period of 20 years from the date the customer's interconnection application was accepted by the utility;

- Customers with DG solar systems are to be considered a separate class of customers for ratemaking purposes; and

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Once an export price is set for APS, no netting or banking of retail credits will be available for new DG customers, and the then-applicable export price will be guaranteed for new customers for a period of 10 years.

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future general retail rate cases, and the policy determinations themselves may be subject to future change, as are all ACC policies. A first-year export energy price of 12.9 cents per kWh is included in the 2017 Settlement Agreement and became effective on September 1, 2017.

In accordance with the 2017 Rate Case Decision, APS filed its request for a second-year export energy price of 11.6 cents per kWh on May 1, 2018. This price reflects the 10% annual reduction discussed above. The new tariff became effective on October 1, 2018.

On January 23, 2017, TASC sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserted that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. TASC filed a Notice of Appeal in the Arizona Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. As part of the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2017 Settlement Agreement described above, TASC agreed to withdraw these appeals when the ACC decision implementing the 2017 Settlement Agreement is no longer subject to appellate review.

Subpoena from Arizona Corporation Commissioner Robert Burns

On August 25, 2016, Commissioner Burns, individually and not by action of the ACC as a whole, served subpoenas in APS's then current retail rate proceeding on APS and Pinnacle West for the production of records and information relating to a range of expenditures from 2011 through 2016. The subpoenas requested information concerning marketing and advertising expenditures, charitable donations, lobbying expenses, contributions to 501(c)(3) and (c)(4) nonprofits and political contributions. The return date for the production of information was set as September 15, 2016. The subpoenas also sought testimony from Company personnel having knowledge of the material, including the Chief Executive Officer.

On September 9, 2016, APS filed with the ACC a motion to quash the subpoenas or, alternatively to stay APS's obligations to comply with the subpoenas and decline to decide APS's motion pending court proceedings. Contemporaneously with the filing of this motion, APS and Pinnacle West filed a complaint for special action and declaratory judgment in the Superior Court of Arizona for Maricopa County, seeking a declaratory judgment that Commissioner Burns' subpoenas are contrary to law. On September 15, 2016, APS produced all non-confidential and responsive documents and offered to produce any remaining responsive documents that are confidential after an appropriate confidentiality agreement is signed.

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC Staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for the production of all information previously requested through the subpoenas. Neither APS nor Pinnacle West produced the information requested and instead objected to the subpoena. On March 10, 2017, Commissioner Burns filed suit against APS and Pinnacle West in the Superior Court of Arizona for Maricopa County in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner

Burns' suit against APS and Pinnacle West. In response to the motion to dismiss, the court stayed the suit and ordered Commissioner Burns to file a motion to compel the production of the information sought by the subpoenas with the ACC. On June 20, 2017, the ACC denied the motion to compel.

On August 4, 2017, Commissioner Burns amended his complaint to add all of the ACC Commissioners and the ACC itself as defendants. All defendants moved to dismiss the amended complaint. On February 15, 2018, the Superior Court dismissed Commissioner Burns’ amended complaint. On March 6, 2018, Commissioner Burns filed an objection to the proposed final order from the Superior Court and a motion to further amend his complaint. The Superior Court permitted Commissioner Burns to amend his complaint to add a claim regarding his attempted investigation into whether his fellow commissioners should have been disqualified from voting on APS’s 2017 rate case. Commissioner Burns filed his second amended complaint, and all defendants filed responses opposing the second amended complaint and requested that it be dismissed. Oral argument occurred in November 2018 regarding the motion to dismiss. On December 18, 2018, the trial court granted the defendants’ motions to dismiss and entered final judgment on January 18, 2019. On February 13, 2019, Commissioner Burns filed a notice of appeal. APS and Pinnacle West cannot predict the outcome of this matter.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Renewable Energy Ballot Initiative

On February 20, 2018, a renewable energy advocacy organization filed with the Arizona Secretary of State a ballot initiative for an Arizona constitutional amendment requiring Arizona public service corporations to provide at least 50% of their annual retail sales of electricity from renewable sources by 2030. For purposes of the proposed amendment, eligible renewable sources would not include nuclear generating facilities. The initiative was placed on the November 2018 Arizona elections ballot. On November 6, 2018, the initiative failed to receive adequate voter support and was defeated.

Energy Modernization Plan

On January 30, 2018, ACC Commissioner Tobin proposed the Energy Modernization Plan, which consists of a series of energy policies tied to clean energy sources such as energy storage, biomass, energy efficiency, electric vehicles, and expanded energy planning through the IRP process. The Energy Modernization Plan includes replacing the current RES standard with a new standard called the CREST, which incorporates the proposals in the Energy Modernization Plan. On February 22, 2018, the ACC Staff filed a Notice of Inquiry to further examine the matter. As a part of this proposal, the ACC voted in March 2018 to direct utilities to develop a comprehensive biomass generation plan to be included in each utility's RES Implementation Plan. On July 5, 2018, Commissioner Tobin's office issued a set of draft CREST rules for the ACC's consideration.

In August 2018, the ACC directed ACC Staff to open a new rulemaking docket which will address a wide range of energy issues, including the Energy Modernization Plan proposals. The rulemaking will consider possible modifications to existing ACC rules, such as the Renewable Energy Standard, Electric and Gas Energy Efficiency Standards, Net Metering, Resource Planning, and the Biennial Transmission Assessment, as well as the development of new rules regarding forest bioenergy, electric vehicles, interconnection of distributed generation, baseload security, blockchain technology and other technological developments, retail competition, and other energy-related topics. Workshops on these energy issues are scheduled to be held throughout 2019. APS cannot predict the outcome of this matter.

Integrated Resource Planning

ACC rules require utilities to develop fifteen-year IRPs which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utility's IRP to determine if it meets the necessary requirements and whether it should be acknowledged. In March of 2018, the ACC reviewed the 2017 IRPs of its jurisdictional utilities and voted to not acknowledge any of the plans. APS does not believe that this lack of acknowledgment will have a material impact on our financial position, results of operations or cash flows. Based on an ACC decision, APS is required to file a Preliminary Resource Plan by April 1, 2019 and its final IRP by April 1, 2020.

Four Corners

SCE-Related Matters. 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 retail 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 included 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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 provided 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 $48 million as of December 31, 2018 and is being amortized in rates over a total of 10 years. The ACC's rate adjustment decision was appealed and on September 26, 2017, the Court of Appeals affirmed the ACC's decision on the Four Corners rate adjustment.

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. 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 established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed a request for rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. On October 5, 2017, FERC issued an order denying APS's request for rehearing. FERC also upheld its prior determination that the agreement relating to the settlement was a jurisdictional contract and should have been filed with FERC. APS cannot predict whether or if the enforcement division will take any action. APS filed an appeal of FERC's July 1, 2016 and October 5, 2017 orders with the United States Court of Appeals for the Ninth Circuit on December 4, 2017. That proceeding is pending, and APS cannot predict the outcome of the proceeding.

SCR Cost Recovery. On December 29, 2017, in accordance with the 2017 Rate Case Decision, APS filed a Notice of Intent to file its SCR Adjustment to permit recovery of costs associated with the installation of SCR equipment at Four Corners Units 4 and 5. APS filed the SCR Adjustment request in April 2018. Consistent with the 2017 Rate Case Decision, the request was narrow in scope and addressed only costs associated with this specific environmental compliance equipment. The SCR Adjustment request provided that there would be a $67.5 million annual revenue impact that would be applied as a percentage of base rates for all applicable customers. Also, as provided for in the 2017 Rate Case Decision, APS requested that the adjustment become effective no later than January 1, 2019. The hearing for this matter occurred in September 2018. At the hearing, APS accepted ACC Staff's recommendation of a lower annual revenue impact of approximately $58.5 million. The Administrative Law Judge issued a Recommended Opinion and Order finding that the costs for the SCR project were prudently incurred and recommending authorization of the $58.5 million annual revenue requirement related to the installation and operation of the SCRs. Exceptions to the Recommended Opinion and Order were filed by the parties and intervenors on December 7, 2018. The ACC has not issued a decision on this matter. APS anticipates a decision later in 2019.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of Cholla 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. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect on April 26, 2017.

Previously, APS estimated Cholla Unit 2’s end of life to be 2033. APS has been recovering a return on and of the net book value of the unit in base rates. Pursuant to the 2017 Settlement Agreement described above, APS will be allowed continued recovery of the net book value of the unit and the unit’s decommissioning and other retirement-related costs ($89 million as of December 31, 2018), 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. The 2017 Settlement Agreement also shortened the depreciation lives of Cholla Units 1 and 3 to 2026.

Navajo Plant

The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant will remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017 that will allow for decommissioning activities to begin after the plant ceases operations in December 2019. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and the U.S. Department of the Interior have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. Although we cannot predict whether any alternate plans will be found that would be acceptable to all of the stakeholders and feasible to implement, we believe it is probable that the current owners of the Navajo Plant will cease operations in December 2019.

On February 14, 2017, the ACC opened a docket titled "ACC Investigation Concerning the Future of the Navajo Generating Station" with the stated goal of engaging stakeholders and negotiating a sustainable pathway for the Navajo Plant to continue operating in some form after December 2019. APS cannot predict the outcome of this proceeding.

APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($88 million as of December 31, 2018) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and may be material. APS believes it will be allowed recovery of the net book value, in addition to a return on its investment. In accordance with GAAP, in the second quarter of 2017, APS's remaining net book value of its interest in the Navajo Plant 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 this interest, 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities

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

s		December 31, 2018		December 31, 2017	
	Amortization Through	Current	Non-Current	Current	Non-Current
Pension	(a)	$—	$733,351	$—	$576,188
Retired power plant costs	2033	28,182	167,164	27,402	188,843
Income taxes - AFUDC equity	2048	6,457	151,467	3,828	142,852
Deferred fuel and purchased power — mark-to-market (Note 16)	2023	31,728	23,768	52,100	34,845
Deferred fuel and purchased power (b) (c)	2019	37,164	—	75,637	—
Four Corners cost deferral	2024	8,077	40,228	8,077	48,305
Income taxes — investment tax credit basis adjustment	2047	1,079	25,522	1,066	26,218
Lost fixed cost recovery (b)	2019	32,435	—	59,844	—
Palo Verde VIEs (Note 18)	2046	—	20,015	—	19,395
Deferred compensation	2036	—	36,523	—	36,413
Deferred property taxes	2027	8,569	66,356	8,569	74,926
Loss on reacquired debt	2038	1,637	13,668	1,637	15,305
Tax expense of Medicare subsidy	2024	1,235	6,176	1,236	7,415
TCA balancing account (b)	2020	3,860	772	1,220	—
AG-1 deferral	2022	2,654	5,819	2,654	8,472
Mead-Phoenix transmission line CIAC	2050	332	10,044	332	10,376
Coal reclamation	2026	1,546	15,607	1,068	12,396
SCR deferral	N/A	—	23,276	—	353
Other	Various	1,947	3,185	3,418	—
Total regulatory assets (d)		$166,902	$1,342,941	$248,088	$1,202,302

(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.

(c) Subject to a carrying charge.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

		December 31, 2018		December 31, 2017	
	Amortization Through	Current	Non-Current	Current	Non-Current
Excess deferred income taxes - ACC - Tax Cuts and Jobs Act	(a)	$—	$1,272,709	$—	$1,266,104
Excess deferred income taxes - FERC - Tax Cuts and Jobs Act	2058	6,302	243,691	—	254,170
Asset retirement obligations	2057	—	278,585	—	332,171
Removal costs	(b)	39,866	177,533	18,238	209,191
Other post retirement benefits	(c)	37,864	125,903	37,642	151,985
Income taxes - deferred investment tax credit	2047	2,164	51,120	2,164	52,497
Income taxes - change in rates	2048	2,769	70,069	2,573	70,537
Spent nuclear fuel	2027	6,503	57,002	6,924	62,132
Renewable energy standard (d)	2020	44,966	20	23,155	—
Demand side management (d)	2020	14,604	4,123	3,066	4,921
Sundance maintenance	2030	1,278	17,228	—	16,897
Deferred gains on utility property	2022	4,423	6,581	4,423	10,988
Four Corners coal reclamation	2038	1,858	17,871	1,858	18,921
Tax expense adjustor mechanism (d)	2019	3,237	—	—	—
Other	Various	42	3,541	43	2,022
Total regulatory liabilities		$165,876	$2,325,976	$100,086	$2,452,536

(a) While the majority of the excess deferred tax balance shown is subject to special amortization rules under federal income tax laws, which require amortization of the balance over the remaining regulatory life of the related property, treatment of a portion of the liability, and the month in which pass-through of the excess deferred tax balance will begin is subject to regulatory approval. This approval will be sought through the Company's TEAM adjustor mechanism. As a result, the Company cannot estimate the amount of this regulatory liability which is expected to reverse within the next 12 months. See Note 4.

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

(c) See Note 7.

(d) See “Cost Recovery Mechanisms” discussion above.

4. Income Taxes

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

APS has recorded regulatory assets and regulatory liabilities related to income taxes on its Balance Sheets in accordance with accounting guidance for regulated operations. The regulatory assets are for certain temporary differences, primarily the allowance for equity funds used during construction, investment tax credit ("ITC") basis adjustment and tax expense of Medicare subsidy. The regulatory liabilities primarily relate to the change in income tax rates and deferred taxes resulting from ITCs.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On December 22, 2017, the Tax Act was enacted. This legislation made significant changes to the federal income tax laws, including a reduction in the corporate tax rate to 21% effective January 1, 2018. As a result of this rate reduction, the Company recognized a $1.14 billion reduction in its net deferred income tax liabilities as of December 31, 2017.

In accordance with accounting for regulated companies, the effect of this rate reduction is substantially offset by a net regulatory liability. As of December 31, 2017, to reflect the $1.14 billion reduction in its net deferred income tax liabilities caused by the rate reduction, APS has recorded a net regulatory liability of $1.52 billion and a new $377 million net deferred tax asset. The Company will amortize the net regulatory liability in accordance with applicable federal income tax laws, which require the amortization of a majority of the balance over the remaining regulatory life of the related property. As a result of the modifications made to the annual transmission formula rate during the second quarter, the Company has recorded amortization of FERC jurisdictional net excess deferred tax liabilities, retroactive to January 1, 2018. The Company continues to work with the ACC on a plan to amortize the remaining net excess deferred tax liabilities subject to its jurisdiction. See Note 3 for more details.

In August 2018, Treasury proposed regulations that clarify bonus depreciation transition rules under the Tax Act for regulated public utility property placed in service after September 27, 2017 and before January 1, 2018. During the third quarter the Company recorded deferred tax liabilities of approximately $11 million and an increase in its net regulatory liability for excess deferred taxes of approximately $9 million, primarily related to bonus depreciation benefits claimed on the Company’s 2017 tax return as a result of this clarifying guidance. However, the proposed regulations are ambiguous with respect to regulated public utility property placed in service on or after January 1, 2018. On December 20, 2018, the Joint Committee on Taxation (“JCT”) released the general explanation of the Tax Act. The document - commonly referred to as the "Blue Book" - provides a comprehensive technical description of the Tax Act and includes the legislative intent of Congress with respect to the changes made by provisions of the Tax Act. The “Blue Book” provides clarification that the intent of the Tax Act was to exclude from the definition of bonus depreciation qualified property any property placed in service by a regulated public utility after December 31, 2017. In a footnote, the JCT indicated that a technical correction bill may be necessary to reflect this intent.

Management recognizes tax positions which it believes are "more likely than not" to be sustained upon examination. In applying this "more likely than not" assessment, the Company is required to consider the technical merits of a position, including legislative intent. As a result, while no legislation has been passed which clarifies the ambiguities related to bonus depreciation for property placed in service on or after January 1, 2018, the Company currently believes the continued availability of bonus depreciation is not "more likely than not" to be sustained upon examination. As a result, the Company has not recognized any current or deferred tax benefits related to bonus depreciation for property placed in service on or after January 1, 2018.

For the quarter ending March 31, 2018, the Company early adopted ASU 2018-02, Income Statement-Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income and elected to reclassify the income tax effects of the Tax Act on items within accumulated other comprehensive income to retained earnings. See Note 2 for additional information.

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.

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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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		
	2018	2017	2016	2018	2017	2016
Total unrecognized tax benefits, January 1	$41,966	$36,075	$34,447	$41,966	$36,075	$34,447
Additions for tax positions of the current year	3,436	2,937	2,695	3,436	2,937	2,695
Additions for tax positions of prior years	2,696	4,783	886	2,696	4,783	886
Reductions for tax positions of prior years for:						
Changes in judgment	(1,764)	(1,829)	(1,953)	(1,764)	(1,829)	(1,953)
Settlements with taxing authorities	—	—	—	—	—	—
Lapses of applicable statute of limitations	(5,603)	—	—	(5,603)	—	—
Total unrecognized tax benefits, December 31	$40,731	$41,966	$36,075	$40,731	$41,966	$36,075

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		
	2018	2017	2016	2018	2017	2016
Tax positions, that if recognized, would decrease our effective tax rate	$19,504	$16,373	$11,313	$19,504	$16,373	$11,313

As of the balance sheet date, the tax year ended December 31, 2015 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 2014.

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		
	2018	2017	2016	2018	2017	2016
Unrecognized tax benefit interest expense/(benefit) recognized	$(780)	$577	$529	$(780)	$577	$529

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		
	2018	2017	2016	2018	2017	2016
Unrecognized tax benefit interest accrued	$1,130	$1,910	$1,333	$1,130	$1,910	$1,333

Additionally, as of December 31, 2018, 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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,		
	2018	2017	2016	2018	2017	2016
Current:						
Federal	$18,375	$11,624	$8,630	$88,180	$21,512	$711
State	3,342	3,052	1,259	1,877	2,778	4,276
Total current	21,717	14,676	9,889	90,057	24,290	4,987
Deferred:						
Federal	94,721	223,729	201,743	32,436	221,078	215,178
State	17,464	19,867	24,779	22,321	23,800	25,677
Total deferred	112,185	243,596	226,522	54,757	244,878	240,855
Income tax expense	$133,902	$258,272	$236,411	$144,814	$269,168	$245,842

The following chart compares pretax income at the statutory federal income tax rate of 21% in 2018 and 35% in 2017 and 2016 to income tax expense (dollars in thousands):

	Pinnacle West Consolidated			APS Consolidated		
	Year Ended December 31,			Year Ended December 31,		
	2018	2017	2016	2018	2017	2016
Federal income tax expense at statutory rate	$139,533	$268,177	$244,278	$154,260	$277,540	$254,617
Increases (reductions) in tax expense resulting from:						
State income tax net of federal income tax benefit	16,411	14,897	16,311	19,091	17,276	18,750
Nondeductible expenditures associated with ballot initiative	7,879	—	—	—	—	—
Stock compensation	(1,804)	(6,659)	(2,951)	(780)	(3,489)	(1,937)
Excess deferred income taxes - Tax Cuts and Jobs Act	(6,725)	9,348	—	(4,715)	9,431	—
Allowance for equity funds used during construction (see Note 1)	(7,231)	(12,937)	(11,724)	(7,231)	(12,937)	(11,724)
Palo Verde VIE noncontrolling interest (see Note 18)	(4,094)	(6,823)	(6,823)	(4,094)	(6,823)	(6,823)
Investment tax credit amortization	(6,742)	(6,715)	(5,887)	(6,742)	(6,715)	(5,887)
Other	(3,325)	(1,016)	3,207	(4,975)	(5,115)	(1,154)
Income tax expense	$133,902	$258,272	$236,411	$144,814	$269,168	$245,842

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Pinnacle West Consolidated		APS Consolidated	
	December 31,		December 31,	
	2018	2017	2018	2017
DEFERRED TAX ASSETS				
Risk management activities	$15,785	$25,103	$15,785	$25,103
Regulatory liabilities:				
Excess deferred income taxes - Tax Cuts and Jobs Act	376,869	376,906	376,869	376,906
Asset retirement obligation and removal costs	117,201	135,847	117,201	135,847
Unamortized investment tax credits	53,284	54,661	53,284	54,661
Other postretirement benefits	40,532	47,021	40,532	47,021
Other	40,380	37,489	40,380	37,489
Pension liabilities	112,019	83,126	107,009	77,280
Coal reclamation liabilities	47,508	45,802	47,508	45,802
Renewable energy incentives	30,779	33,546	30,779	33,546
Credit and loss carryforwards	1,755	53,946	—	1,920
Other	58,820	56,630	59,919	62,421
Total deferred tax assets	894,932	950,077	889,266	897,996
DEFERRED TAX LIABILITIES				
Plant-related	(2,277,724)	(2,220,886)	(2,277,724)	(2,220,886)
Risk management activities	(237)	(491)	(237)	(491)
Other postretirement assets and other special use funds	(57,697)	(66,134)	(57,274)	(65,733)
Regulatory assets:				
Allowance for equity funds used during construction	(39,086)	(36,365)	(39,086)	(36,365)
Deferred fuel and purchased power	(23,086)	(40,778)	(23,086)	(40,778)
Pension benefits	(181,504)	(142,848)	(181,504)	(142,848)
Retired power plant costs (see Note 3)	(48,348)	(53,611)	(48,348)	(53,611)
Other	(72,096)	(74,423)	(72,096)	(74,423)
Other	(2,575)	(5,346)	(2,575)	(5,346)
Total deferred tax liabilities	(2,702,353)	(2,640,882)	(2,701,930)	(2,640,481)
Deferred income taxes — net	$(1,807,421)	$(1,690,805)	$(1,812,664)	$(1,742,485)

As of December 31, 2018, the deferred tax assets for credit and loss carryforwards relate primarily to federal general business credits of approximately $14 million, which first begin to expire in 2036, and state credit carryforwards net of federal benefit of $7 million, which first begin to expire in 2023. The credit and loss carryforwards amount above has been reduced by $19 million of unrecognized tax benefits.

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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below presents the consolidated credit facilities and the amounts available and outstanding as of December 31, 2018 and 2017 (dollars in thousands):

	December 31, 2018			December 31, 2017		
	Pinnacle West	APS	Total	Pinnacle West	APS	Total
Commitments under Credit Facilities	$350,000	$1,000,000	$1,350,000	$325,000	$1,000,000	$1,325,000
Outstanding Commercial Paper and Revolving Credit Facility Borrowings	(76,400)	—	(76,400)	(95,400)	—	(95,400)
Amount of Credit Facilities Available	$273,600	$1,000,000	$1,273,600	$229,600	$1,000,000	$1,229,600
Weighted-Average Commitment Fees	0.125%	0.100%		0.125%	0.100%	

Pinnacle West

On June 28, 2018, Pinnacle West refinanced its 364-day $125 million unsecured revolving credit facility that would have matured on July 30, 2018 with a new 364-day $150 million credit facility that matures June 27, 2019. Borrowings under the facility bear interest at LIBOR plus 0.70% per annum. At December 31, 2018, Pinnacle West had $54 million outstanding under the facility.

On July 12, 2018, Pinnacle West replaced its $200 million revolving credit facility that would have matured in May 2021, with a new $200 million facility that matures in July 2023. 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, 2018, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $22 million of commercial paper borrowings.

APS

On July 12, 2018, APS replaced its $500 million revolving credit facility that would have matured in May 2021, with a new $500 million facility that matures in July 2023.

At December 31, 2018, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in June 2022 and the above-mentioned $500 million facility. APS may increase the amount of each facility up to a maximum of $700 million, 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 $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2018, APS had no commercial paper outstanding and 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 November 27, 2018, 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 (i) 7% of APS’s capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power). See Note 6 for additional long-term debt provisions.

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, 2018 and 2017 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2018	2017
APS				
Pollution control bonds:				
Variable	2029	(b)	$35,975	$35,975
Fixed	2024	4.70%	115,150	147,150
Total pollution control bonds			151,125	183,125
Senior unsecured notes	2019-2048	2.20%-8.75%	4,575,000	4,275,000
Term loans		(c)	—	150,000
Unamortized discount			(12,638)	(11,288)
Unamortized premium			7,736	8,049
Unamortized debt issuance cost			(31,787)	(31,594)
Total APS long-term debt			4,689,436	4,573,292
Less current maturities			500,000	82,000
Total APS long-term debt less current maturities			4,189,436	4,491,292
Pinnacle West				
Senior unsecured notes	2020	2.25%	300,000	300,000
Term loan	2020	(d)	150,000	—
Unamortized discount			(121)	(184)
Unamortized debt issuance cost			(1,083)	(1,395)
Total Pinnacle West long-term debt			448,796	298,421
Less current maturities			—	—
Total Pinnacle West long-term debt less current maturities			448,796	298,421
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$4,638,232	$4,789,713

(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 1.76% at December 31, 2018 and 1.77% at December 31, 2017.
(c) The weighted-average interest rate was 2.24% at December 31, 2017.
(d) The weighted-average interest rate was 3.02% at December 31, 2018.

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
2019	$500,000	$500,000

2020	700,000	250,000
2021	—	—
2022	—	—
2023	—	—
Thereafter	3,976,125	3,976,125
Total	$5,176,125	$4,726,125

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Debt Fair Value

Our long-term debt fair value estimates are classified within Level 2 of the fair value hierarchy. The following table represents the estimated fair value of our long-term debt, including current maturities (dollars in thousands):

	As of December 31, 2018		As of December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$448,796	$443,955	$298,421	$298,608
APS	4,689,436	4,789,608	4,573,292	5,006,348
Total	$5,138,232	$5,233,563	$4,871,713	$5,304,956

Credit Facilities and Debt Issuances

Pinnacle West

On December 21, 2018, Pinnacle West entered into a $150 million term loan facility that matures December 2020. The proceeds were used for general corporate purposes.

APS

On May 30, 2018, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series C, due 2029. These bonds were classified as current maturities of long-term debt on our Consolidated Balance Sheets at December 31, 2017.

On June 26, 2018, APS repaid at maturity APS's $50 million term loan facility.

On August 9, 2018, APS issued $300 million of 4.20% unsecured senior notes that mature on August 15, 2048. The net proceeds from the sale of the notes were used to repay commercial paper borrowings.

On November 30, 2018, APS repaid its $100 million term loan facility that would have matured April 22, 2019.

On December 21, 2018, Pinnacle West contributed $150 million into APS in the form of an equity infusion. APS used this contribution to repay short-term indebtedness.

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, 2018, the ratio was approximately 50% 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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 November 27, 2018, 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$5.1 billion to $5.9 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs. 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 other postretirement benefit plans (Pinnacle West Capital Corporation Group Life and Medical Plan and Pinnacle West Capital Corporation Post-65

Retiree Health Reimbursement Arrangement) for the employees of Pinnacle West and its subsidiaries. These plans provide 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.

Because of plan changes in 2014, the Company sought IRS approval to move approximately $186 million of other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs. In December 2016, FERC approved a methodology for determining the amount of other postretirement benefit trust assets to transfer into a new trust account to pay for active union employee medical costs. On January 2, 2018, these funds were moved to the new trust account, which is included in the other special use funds on the Consolidated Balance Sheets. The Company and the IRS executed a final Closing Agreement on March 2, 2018. The Company made an informational filing with FERC during February 2018. It is the Company’s understanding that completion of these regulatory requirements permits access to approximately $186 million for the sole purpose of paying active union employee medical benefits.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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 or billed to electric plant participants) (dollars in thousands):

	Pension			Other Benefits		
	2018	2017	2016	2018	2017	2016
Service cost-benefits earned during the period	$56,669	$54,858	$53,792	$21,100	$17,119	$14,993
Interest cost on benefit obligation	124,689	129,756	131,647	28,147	29,959	29,721
Expected return on plan assets	(182,853)	(174,271)	(173,906)	(42,082)	(53,401)	(36,495)
Amortization of:						
Prior service cost (credit)	—	81	527	(37,842)	(37,842)	(37,883)
Net actuarial loss	32,082	47,900	40,717	—	5,118	4,589
Net periodic benefit cost (benefit)	$30,587	$58,324	$52,777	$(30,677)	$(39,047)	$(25,075)
Portion of cost charged to expense	$10,120	$27,295	$26,172	$(21,426)	$(18,274)	$(12,435)

On January 1, 2018, we adopted new accounting standard ASU 2017-07, Compensation-Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This new standard changed our income statement presentation of net periodic benefit cost/(credits) and allows only the service cost component of net periodic benefit cost to be eligible for capitalization. See Note 2 for additional information.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the plans' changes in the benefit obligations and funded status for the years 2018 and 2017 (dollars in thousands):

	Pension		Other Benefits	
	2018	2017	2018	2017
Change in Benefit Obligation				
Benefit obligation at January 1	$3,394,186	$3,204,462	$753,393	$716,445
Service cost	56,669	54,858	21,100	17,119
Interest cost	124,689	129,756	28,147	29,959
Benefit payments	(184,161)	(166,342)	(31,540)	(30,144)
Actuarial (gain) loss	(200,757)	171,452	(94,329)	20,014
Benefit obligation at December 31	3,190,626	3,394,186	676,771	753,393
Change in Plan Assets				
Fair value of plan assets at January 1	3,057,027	2,675,357	1,022,371	882,651
Actual return on plan assets	(201,078)	428,374	(40,354)	139,367
Employer contributions	50,000	100,000	—	353
Benefit payments	(172,473)	(146,704)	(72,453)	—
Transfer to active union medical account	—	—	(185,887)	—
Fair value of plan assets at December 31	2,733,476	3,057,027	723,677	1,022,371
Funded Status at December 31	$(457,150)	$(337,159)	$46,906	$268,978

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, 2018 and 2017 (dollars in thousands):

	2018	2017
Projected benefit obligation	$3,190,626	$3,394,186
Accumulated benefit obligation	3,038,774	3,227,233
Fair value of plan assets	2,733,476	3,057,027

The following table shows the amounts recognized on the Consolidated Balance Sheets as of December 31, 2018 and 2017 (dollars in thousands):

	Pension		Other Benefits	
	2018	2017	2018	2017
Noncurrent asset	$—	$—	$46,906	$268,978
Current liability	(13,980)	(9,859)	—	—
Noncurrent liability	(443,170)	(327,300)	—	—
Net amount recognized	$(457,150)	$(337,159)	$46,906	$268,978

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the details related to accumulated other comprehensive loss as of December 31, 2018 and 2017 (dollars in thousands):

	Pension		Other Benefits	
	2018	2017	2018	2017
Net actuarial loss	$794,292	$643,199	$63,544	$75,439
Prior service credit	—	—	(227,733)	(265,575)
APS's portion recorded as a regulatory (asset) liability	(733,351)	(576,188)	163,767	189,627
Income tax expense (benefit)	(15,083)	(24,915)	561	853
Accumulated other comprehensive loss	$45,858	$42,096	$139	$344

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 2019 (dollars in thousands):

	Pension	Other Benefits
Net actuarial loss	$43,248	$—
Prior service credit	—	(37,821)
Total amounts estimated to be amortized from accumulated other comprehensive loss (gain) and regulatory assets (liabilities) in 2019	$43,248	$(37,821)

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,		
	2018	2017	2018	2017	2016
Discount rate – pension	4.34 %	3.65 %	3.65 %	4.08 %	4.37 %
Discount rate – other benefits	4.39 %	3.71 %	3.71 %	4.17 %	4.52 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %	4.00 %	4.00 %
Expected long-term return on plan assets - pension	N/A	N/A	6.05 %	6.55 %	6.90 %
Expected long-term return on plan assets - other benefits	N/A	N/A	5.40 %	6.05 %	4.45 %
Initial healthcare cost trend rate (pre-65 participants)	7.00 %	7.00 %	7.00 %	7.00 %	7.00 %
Initial healthcare cost trend rate (post-65 participants)	4.75 %	4.75 %	4.75 %	5.00 %	5.00 %
Ultimate healthcare cost trend rate	4.75 %	4.75 %	4.75 %	5.00 %	5.00 %
Number of years to ultimate trend rate (pre-65 participants)	7	8	8	4	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 2019, we are assuming a 6.25% long-term rate of return for pension assets and 5.55% (before tax) for other benefit assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 on our December 31, 2018 amounts (dollars in thousands):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 10,235	$ (4,322)
Effect on service and interest cost components of net periodic other postretirement benefit costs	11,223	(8,479)
Effect on the accumulated other postretirement benefit obligation	101,224	(81,144)

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.

Changes in the value of long-term fixed income assets, also known as liability-hedging assets, are intended 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 and other government agencies, U.S. Treasury Futures Contracts, and fixed income debt securities issued by corporations. Long-term fixed income assets may also include interest rate swaps, 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 also hold investments in return-generating assets by holding securities in partnerships, common and collective trusts and mutual funds.

Based on the IPS, and given the pension plan's funded status at year-end 2018, the target and actual allocation for the pension plan at December 31, 2018 are as follows:

	Pension			
	Target Allocation		Actual Allocation	
Long-term fixed income assets	62	%	64	%
Return-generating assets	38	%	36	%
Total	100	%	100	%

The permissible range is within +/- 3% of the target allocation shown in the above table, and also considers the Plan's funded status.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the additional target allocations, as a percent of total pension plan assets, for the return-generating assets:

Asset Class	Target Allocation	
Equities in US and other developed markets	18	%
Equities in emerging markets	6	%
Alternative investments	14	%
Total	38	%

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, 2018, 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. The following table presents the actual allocations of the investment for the other postretirement benefit plan at December 31, 2018:

	Other Benefits Actual Allocation	
Long-term fixed income assets	69	%
Return-generating assets	31	%
Total	100	%

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, U.S. Treasury Futures Contracts, 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. U.S. Treasury Futures Contracts are valued using the quoted active market prices from the exchange on which they trade, 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. Mutual funds, which includes exchange traded funds (ETFs), are classified as Level 1 and valued using a NAV that is observable and 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. Investments in common and collective trusts are valued using NAV as a practical expedient and, accordingly, are not classified in the fair value hierarchy. The NAV for trusts investing in exchange traded equities, and fixed income securities is derived from the market prices of the underlying securities held by the trusts. The

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2018, the plans were able to transact in the common and collective trusts at NAV.

Investments in partnerships are also valued using the concept of NAV as a practical expedient and, accordingly, are not classified in the fair value hierarchy. The NAV for these investments 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, 2018, approximately $62 million of these commitments have been funded.

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 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2018, 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)	Other (a)	Balance at December 31, 2018
Pension Plan:				
Cash and cash equivalents	$ 451	$—	$—	$ 451
Fixed income securities:				
Corporate	—	1,237,744	—	1,237,744
U.S. Treasury	372,649	—	—	372,649
Other (b)	—	78,902	—	78,902
Common stock equities (c)	196,661	—	—	196,661
Mutual funds (d)	120,976	—	—	120,976
Common and collective trusts:				
Equities	—	—	272,926	272,926
Real estate	—	—	165,123	165,123
Fixed Income	—	—	86,483	86,483
Partnerships	—	—	125,217	125,217
Short-term investments and other (e)	—	—	76,344	76,344
Total	$ 690,737	$ 1,316,646	$ 726,093	$ 2,733,476
Other Benefits:				
Cash and cash equivalents	$ 93	$—	$—	$ 93
Fixed income securities:				
Corporate	—	163,286	—	163,286
U.S. Treasury	318,017	—	—	318,017
Other (b)	—	7,531	—	7,531
Common stock equities (c)	129,199	—	—	129,199
Mutual funds (d)	10,963	—	—	10,963
Common and collective trusts:				
Equities	—	—	65,720	65,720
Real estate	—	—	19,054	19,054
Short-term investments and other (e)	3,633	—	6,181	9,814
Total	$ 461,905	$ 170,817	$ 90,955	$ 723,677

(a) These investments primarily represent assets valued using net asset value as a practical expedient, and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in international common stock equities.
(e) This category includes plan receivables and payables.

145

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of Pinnacle West's pension plan and other postretirement benefit plan assets at December 31, 2017, 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)	Other (a)	Balance at December 31, 2017
Pension Plan:				
Cash and cash equivalents	$ 3,830	$—	$—	$3,830
Fixed income securities:				
Corporate	—	1,365,194	—	1,365,194
U.S. Treasury	221,291	—	—	221,291
Other (b)	—	100,599	—	100,599
Common stock equities (c)	228,088	—	—	228,088
Mutual funds (d)	233,732	—	—	233,732
Common and collective trusts:				
Equities	—	—	408,763	408,763
Real estate	—	—	171,569	171,569
Fixed Income	—	—	90,869	90,869
Partnerships	—	—	133,379	133,379
Short-term investments and other (e)	—	1,208	98,505	99,713
Total	$ 686,941	$1,467,001	$903,085	$3,057,027
Other Benefits:				
Cash and cash equivalents	$ 143	$—	$—	$143
Fixed income securities:				
Corporate	—	306,008	—	306,008
U.S. Treasury	336,963	—	—	336,963
Other (b)	—	32,508	—	32,508
Common stock equities (c)	196,153	—	—	196,153
Mutual funds (d)	39,269	—	—	39,269
Common and collective trusts:				
Equities	—	—	75,310	75,310
Real estate	—	—	15,422	15,422
Short-term investments and other (e)	11,268	149	9,178	20,595
Total	$ 583,796	$338,665	$99,910	$1,022,371

(a) These investments primarily represent assets valued using net asset value as a practical expedient, and have not been classified in the fair value hierarchy.
(b) This category consists primarily of debt securities issued by municipalities.
(c) This category primarily consists of U.S. common stock equities.
(d) These funds invest in U.S. and international common stock equities.
(e) This category includes plan receivables and payables.

Contributions

Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We made contributions to our pension plan totaling $50 million in 2018, $100 million in 2017, and $100 million in 2016. 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 $350 million during the 2019-2021 period.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

With regard to contributions to our other postretirement benefit plan, we did not make a contribution in 2018. We made a contribution of approximately $1 million in each of 2017 and 2016. We do not expect to make any contributions over the next three years to our other postretirement benefit plans. In 2018, the Company was reimbursed $72 million for prior years retiree medical claims from the other postretirement benefit plan trust assets.

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
2019	$ 188,492	$ 32,622
2020	193,087	34,199
2021	198,471	35,551
2022	204,399	36,673
2023	211,346	37,405
Years 2024-2028	1,093,319	187,023

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 2018, 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 future contributions. Pinnacle West recorded expenses for this plan of approximately $11 million for 2018, $10 million for 2017, and $10 million for 2016.

8. Leases

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

Lease expense recognized in the Consolidated Statements of Income was $18 million in 2018, $18 million in 2017, and $16 million in 2016. APS's lease expense was $17 million in 2018, $17 million in 2017, and $15 million in 2016. These amounts do not include purchased power lease contracts, discussed below.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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
2019	$ 13,747	$ 13,411
2020	12,428	12,143
2021	9,478	9,282
2022	6,513	6,321
2023	5,359	5,171
Thereafter	42,236	40,656
Total future lease commitments	$ 89,761	$ 86,984

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.

Purchased Power Lease Contracts

A purchased power contract may contain a lease for accounting purposes. This generally occurs when a purchased power contract designates a specific power plant from which the buyer purchases substantially all of the output and also meets other required lease accounting criteria. APS has certain purchased power contracts that contain lease arrangements. The future minimum lease payments due under these contracts are $54 million, all of which relate to 2019. Due to the inherent uncertainty associated with the reliability of the fuel source, payments under most renewable purchased power lease contracts are considered contingent rents and are excluded from future minimum lease payments. See Note 10 for additional information on our purchased power contract estimated commitments.

Operating lease cost for purchased power lease contracts was $47 million in 2018, $60 million in 2017 and $82 million in 2016. In addition, contingent rents for purchased power lease contracts was $109 million in 2018, $100 million in 2017, and $88 million in 2016. These costs are recorded in fuel and purchased power on the Consolidated Statements of Income, and are subject to recovery under the PSA or RES. See Note 3.

See Note 2 for a discussion of the new lease accounting standard we adopted on January 1, 2019.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 Statements 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, 2018 (dollars in thousands):

	Percent Owned		Plant in Service	Accumulated Depreciation	Construction Work in Progress
Generating facilities:					
Palo Verde Units 1 and 3	29.1%		$1,887,729	$1,095,878	$ 25,185
Palo Verde Unit 2 (a)	16.8%		638,419	369,372	20,852
Palo Verde Common	28.0%	(b)	752,300	277,414	39,995
Palo Verde Sale Leaseback		(a)	351,050	245,275	—
Four Corners Generating Station	63.0%		1,466,579	544,308	23,430
Cholla common facilities (c)	50.5%		183,390	82,434	893
Transmission facilities:					
ANPP 500kV System	33.5%	(b)	129,587	49,340	2,705
Navajo Southern System	26.7%	(b)	82,046	30,464	284
Palo Verde — Yuma 500kV System	19.0%	(b)	15,304	6,729	530
Four Corners Switchyards	63.1%	(b)	68,707	15,436	1,334
Phoenix — Mead System	17.1%	(b)	39,329	18,527	44
Palo Verde — Rudd 500kV System	50.0%		93,887	25,573	302
Morgan — Pinnacle Peak System	64.6%	(b)	117,722	16,744	—
Round Valley System	50.0%		515	153	—
Palo Verde — Morgan System	87.9%	(b)	219,292	6,660	—
Hassayampa — North Gila System	80.0%		142,541	9,805	—
Cholla 500kV Switchyard	85.7%		5,078	1,414	38
Saguaro 500kV Switchyard	60.0%		20,414	12,790	—
Kyrene — Knox System	50.0%		578	307	—

(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.

APS also has a 14% ownership in the Navajo Plant. In the second quarter of 2017, APS's remaining net book value of its interest was reclassified from property, plant and equipment to a regulatory asset. See "Navajo Plant" in Note 3 for more details.

149

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. Commitments and Contingencies

Palo Verde 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 the DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to the 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 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 the DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by the 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 reported net income. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019.

APS has submitted four claims pursuant to the terms of the August 18, 2014 settlement agreement, for four separate time periods during July 1, 2011 through June 30, 2018. The DOE has approved and paid $74.2 million for these claims (APS's share is $21.6 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers (see Note 3). APS's next claim pursuant to the terms of the August 18, 2014 settlement agreement was submitted to the DOE on October 31, 2018 in the amount of $10.2 million (APS's share is $3.0 million). This claim is pending DOE review.

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-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident of up to approximately $14.1 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of approximately $13.6 billion of liability coverage is provided through a mandatory industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $137.6 million, subject to a maximum annual premium of approximately $20.5 million per incident. Based on APS's ownership interest in the three Palo Verde units, APS's maximum retrospective premium per incident for all three units is approximately $120.1 million, with a maximum annual retrospective premium of approximately $17.9 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

("NEIL"). APS is subject to retrospective premium adjustments 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 $24.8 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 $71.2 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.

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 2019 and 2043 that include required purchase provisions. APS estimates the contract requirements to be approximately $622 million in 2019; $555 million in 2020; $558 million in 2021; $563 million in 2022; $560 million in 2023; and $5.9 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. These amounts include estimated commitments relating to purchased power lease contracts, see Note 8.

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,					
	2019	2020	2021	2022	2023	Thereafter
Coal take-or-pay commitments (a)	$179,879	$181,059	$184,944	$186,244	$187,518	$1,422,253

(a) Total take-or-pay commitments are approximately $2.3 billion. The total net present value of these commitments is approximately $1.7 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 amounts purchased under the coal contracts which include take-or-pay provisions for each of the last three years (dollars in thousands):

	Year Ended December 31,		
	2018	2017	2016
Total purchases	$206,093	$165,220	$160,066

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 $37 million in 2019; $36 million in 2020; $34 million in 2021; $31 million in 2022; $30 million in 2023; and $155 million thereafter. These amounts do not include purchases of renewable energy credits that are bundled with energy.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 $213 million at December 31, 2018 and $216 million at December 31, 2017. Under our current coal supply agreements, APS expects to make payments for the final mine reclamation as follows: $32 million in 2019; $21 million in 2020; $21 million in 2021; $22 million in 2022; $24 million in 2023; and $167 million thereafter. Any amendments to current coal supply agreements may change the timing of the contribution. Portions of 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

The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA" or "Superfund") establishes liability for the cleanup of hazardous substances found contaminating the soil, water or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible ("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 ("RI/FS"). Based upon discussions between the OU3 working group parties and EPA, along with the results of recent technical analyses prepared by the OU3 working group to supplement the RI/FS for OU3, APS anticipates finalizing the RI/FS in the fall or winter of 2019. 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, 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 facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation, but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APS's exposure or risk related to these matters.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RID's CERCLA claims concerning both past and future cost recovery. APS's share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. In addition, APS and certain other parties not named in the remaining RID service provider lawsuit may be brought into the litigation via third-party complaints filed by the current direct defendants. 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.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, 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 pollution control requirements on Four Corners and the Navajo Plant. EPA will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants. In addition, EPA issued a final rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See below for details of the Cholla BART approval.

Four Corners. Based on EPA’s final standards, APS's 63% share of the cost of required controls for Four Corners Units 4 and 5 is approximately $400 million, the majority of which has already been incurred. 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. 4CA purchased the El Paso interest on July 6, 2016. NTEC purchased the interest from 4CA on July 3, 2018. See "Four Corners Coal Supply Agreement - 4CA Matter" below for a discussion of the NTEC purchase. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest.

Navajo Plant. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's Federal Implementation Plan ("FIP"), could be up to approximately $200 million; however, given the future plans for the Navajo Plant, we do not expect to incur these costs. See "Navajo Plant" in Note 3 for information regarding future plans for the Navajo Plant.

Cholla. APS believed that EPA's original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of SCR controls, was unsupported and that EPA had no basis for disapproving Arizona's State Implementation Plan ("SIP") and promulgating a FIP that was inconsistent with the state's considered BART determinations under the regional haze program. In September 2014, APS met with EPA to propose a compromise BART strategy, whereby 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

cost effective than, and will result in increased visibility improvement over, the BART requirements for oxides of nitrogen ("NOx") imposed through EPA's BART FIP. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which took effect for Cholla on April 26, 2017.

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 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. Such closure requirements are deemed "forced closure" or "closure for cause" of unlined surface impoundments, and are the subject of recent regulatory and judicial activities described below.

On December 16, 2016, President Obama signed the Water Infrastructure Improvements for the Nation ("WIIN") Act into law, which contains a number of provisions requiring EPA to modify the self-implementing provisions of the Agency's current CCR rules under Subtitle D. Such modifications include new EPA authority to directly enforce the CCR rules through the use of administrative orders and providing states, like Arizona, where the Cholla facility is located, the option of developing CCR disposal unit permitting programs, subject to EPA approval. For facilities in states that do not develop state-specific permitting programs, EPA is required to develop a federal permit program, pending the availability of congressional appropriations. By contrast, for facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation, where the Navajo Plant and Four Corners facilities are located, EPA is required to develop a federal permit program regardless of appropriated funds.

ADEQ has initiated a process to evaluate how to develop a state CCR permitting program that would cover electric generating units ("EGUs"), including Cholla. While APS has been working with ADEQ on the development of this program, we are unable to predict when

Arizona will be able to finalize and secure EPA approval for a state-specific CCR permitting program. With respect to the Navajo Nation, APS has sought clarification as to when and how EPA would be initiating permit proceedings for facilities on the reservation, including Four Corners. We are unable to predict at this time when EPA will be issuing CCR management permits for the facilities on the Navajo Nation. At this time, it remains unclear how the CCR provisions of the WIIN Act will affect APS and its management of CCR.

Based upon utility industry petitions for EPA to reconsider the RCRA Subtitle D regulations for CCR, which were premised in part on the CCR provisions of the 2016 WIIN Act, on September 13, 2017 EPA agreed to evaluate whether to revise these federal CCR regulations. On July 17, 2018, EPA finalized a revision to its RCRA Subtitle D regulations for CCR, the "Phase I, Part I" revision to its CCR regulations, deferring for future action a number of other proposed changes contemplated in a March 1, 2018 proposal. For the final rule issued on July 17, 2018, EPA established nationwide health-based standards for certain constituents of CCR subject to groundwater corrective action and delayed the closure deadlines for certain unlined CCR surface impoundments by 18 months (for example, those disposal units required to undergo forced closure). These changes to the federal regulations governing CCR disposal are unlikely to have a material impact on APS. As for those aspects of the March 2018 rulemaking proposal for which EPA has yet to take final action, it remains unclear which specific provisions of the federal CCR rules will ultimately be modified, how they will be modified, or when such modification will occur.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA's CCR regulations, EPA is required to complete a rulemaking proceeding in the near future concerning whether or not boron must be included on the list of groundwater constituents that might trigger corrective action under EPA's CCR rules. Simultaneously with the issuance of EPA's proposed modifications to the federal CCR rules in response to industry petitions, on March 1, 2018, EPA issued a proposed rule seeking comment as to whether or not boron should be included on this list. EPA is not required to take final action approving the inclusion of boron. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time APS cannot predict the eventual results of this rulemaking proceeding concerning boron.

On August 21, 2018, the D.C. Circuit Court issued its decision on the merits in this litigation. The Court upheld the legality of EPA's CCR regulations, though it vacated and remanded back to EPA a number of specific provisions, which are to be corrected in accordance with the Court's order. Among the issues affecting APS's management of CCR, the D.C. Circuit's decision vacated and remanded those provisions of the EPA CCR regulations that allow for the operation of unlined CCR surface impoundments, even where those unlined impoundments have not otherwise violated a regulatory location restriction or groundwater protection standard (i.e., otherwise triggering forced closure). At this time, it remains unclear how this D.C. Circuit Court decision will affect APS's operations or any financial impacts, as EPA has yet to take regulatory action on remand to revise its 2015 CCR regulations consistent with the Court's order.

Based on this decision, on December 17, 2018, certain environmental groups filed an emergency motion with the D.C. Circuit to either stay or summarily vacate EPA's July 17, 2018 final rule extending the closure-initiation deadline for certain unlined CCR surface impoundments until October 2020. In response, EPA filed a motion to remand but not vacate that deadline extension regulation. We cannot predict the outcome of the D.C. Circuit's consideration of these dueling motions, and whether or how such a ruling would affect APS's operations.

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 $22 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $20 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. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. By October 17, 2017, electric utility companies that own or operate CCR disposal units, such as APS, must have collected sufficient groundwater sampling data to initiate a detection monitoring program. To the extent that certain threshold constituents are identified through this initial detection monitoring at levels above the CCR rule's standards, the rule required the initiation of an assessment monitoring program by April 15, 2018.

APS recently completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, all such units must cease operating and initiate closure by October of 2020. APS currently estimates that the additional incremental costs to complete this corrective action and closure work, along with the costs to develop replacement CCR disposal capacity, could be approximately $5 million for both Cholla and Four Corners. APS initiated an assessment of corrective measures on January 14, 2019, and anticipates completing this assessment during the summer of 2019. During this assessment, APS will gather additional groundwater data, solicit input from the public, host public hearings, and select remedies. As such, this $5 million cost estimate may change based upon APS's performance of the CCR rule's corrective action assessment process. Given uncertainties that may exist until we have fully completed the corrective

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe any potential change to the cost estimate would have a material impact on our financial position, results of operations or cash flows.

Clean Power Plan. On June 2, 2014, EPA issued two proposed rules to regulate greenhouse gas ("GHG") emissions from modified and reconstructed 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 carbon pollution standards for EGUs, the "Clean Power Plan". On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan and proposed replacement regulations on August 21, 2018. In addition, judicial challenges to the Clean Power Plan are pending before the D.C. Circuit, though that litigation is currently in abeyance while EPA develops regulatory action to potentially repeal and replace that regulation.

EPA's pending proposal to regulate carbon emissions from EGUs replaces the Clean Power Plan with standards that are based entirely upon measures that can be implemented to improve the heat rate of steam-electric power plants, specifically coal-fired EGUs. In contrast with the Clean Power Plan, EPA's proposed "Affordable Clean Energy Rule" would not involve utility-level generation dispatch shifting away from coal-fired generation and toward renewable energy resources and natural gas-fired combined cycle power plants. In addition, to address the New Source Review ("NSR") implications of power plant upgrades potentially necessary to achieve compliance with the proposed Affordable Clean Energy Rule standards, EPA also proposed to revise EPA's NSR regulations to more readily authorize the implementation of EGU efficiency upgrades.

We cannot predict the outcome of EPA's regulatory actions related to the August 2015 carbon pollution standards for EGU's, including any actions related to EPA's repeal proposal for the Clean Power Plan or additional rulemaking actions to approve the EPA's recently proposed Affordable Clean Energy Rule. In addition, we cannot predict whether the D.C. Circuit Court will continue to hold the litigation challenging the original Clean Power Plan in abeyance in light of EPA's repeal proposal, which is still pending.

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, 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.

Federal Agency Environmental Lawsuit Related to Four Corners

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA") in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the Arizona District Court issued an order granting NTEC's motion, dismissing the litigation with prejudice, and terminating the proceedings. On November 9, 2017, the environmental group plaintiffs appealed the district court order dismissing their lawsuit. Oral argument for this appeal has been scheduled for March 2019. We cannot predict whether this appeal will be successful and, if it is successful, the outcome of further district court proceedings.

Four Corners National Pollutant Discharge Elimination System ("NPDES") Permit

On July 16, 2018, several environmental groups filed a petition for review before the EPA Environmental Appeals Board ("EAB") concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPA’s 2015 revised effluent limitation guidelines for steam-electric EGUs, 2014 existing-source regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018 to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. EPA indicated that it anticipates proposing a replacement NPDES permit by March 2019 and, depending on the extent of public comments concerning that proposal, taking final action on a new NPDES permit by June 2019. At this time, we cannot predict the outcome of EPA's reconsideration of the NPDES permit and whether reconsideration will have a material impact on our financial position, results of operations or cash flows.

Four Corners Coal Supply Agreement

Arbitration

On June 13, 2017, APS received a Demand for Arbitration from NTEC in connection with the Coal Supply Agreement, dated December 30, 2013, under which NTEC supplies coal to APS and the other Four Corners owners (collectively, the “Buyer”) for use at the Four Corners Power Plant (the "2016 Coal Supply Agreement"). NTEC was originally seeking a declaratory judgment to support its interpretation of a provision regarding uncontrollable forces in the agreement that relates to annual minimum quantities of coal to be purchased by the Buyer. NTEC also alleged a shortfall in the Buyer's purchases for the initial contract year of approximately $30 million. APS's share of this amount is approximately $17 million. On September 20, 2017, NTEC amended its Demand for Arbitration, removing its request for a declaratory judgment and at such time was only seeking relief for the alleged shortfall in the Buyer's purchases for the initial contract year.

On June 29, 2018, the parties settled the dispute for $45 million, which includes settlement for the initial contract year and the current contract year. APS's share of this amount is approximately $34 million. In connection with the settlement, the parties amended the 2016 Coal Supply Agreement, including modifying the provisions that gave rise to this dispute. (See "4CA Matter" below for additional matters agreed to between 4CA and NTEC in the settlement arrangement.) The arbitration was dismissed on July 9, 2018.

Coal Advance Purchase

On March 12, 2018, APS paid to NTEC approximately $24 million as an advance payment for APS's share of coal under the 2016 Coal Supply Agreement. The coal inventory purchased represents an amount that APS expects to use for its plant operations within the next year.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4CA Matter

On July 6, 2016, 4CA purchased El Paso's 7% interest in Four Corners. NTEC had the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The purchase did not occur during the originally contemplated timeframe. Concurrent with the settlement of the 2016 Coal Supply Agreement matter described above, NTEC and 4CA agreed to allow for the purchase by NTEC of the 7% interest, consistent with the option. On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CA's 7% interest in Four Corners. Completion of the sale was subject to the receipt of approval by FERC, which was received on July 2, 2018, and the sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CA's book value, approximately $70 million, and will pay 4CA the purchase price over a period of four years pursuant to a secured interest-bearing promissory note. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTEC's 7% share of capital expenditures and operating and maintenance expenses. Pinnacle West's guarantee is secured by a portion of APS's payments to be owed to NTEC under the 2016 Coal Supply Agreement.

The 2016 Coal Supply Agreement contained alternate pricing terms for the 7% interest in the event NTEC did not purchase the interest. Until the time that NTEC purchased the 7% interest, the alternate pricing provisions were applicable to 4CA as the holder of the 7% interest. These terms included a formula under which NTEC must make certain payments to 4CA for reimbursement of operations and maintenance costs and a specified rate of return, offset by revenue generated by 4CA's power sales. Such payments are due to 4CA at the end of each calendar year. A $10 million payment was due to 4CA at December 31, 2017, which NTEC satisfied by directing to 4CA a prepayment from APS of a portion of a future mine reclamation obligation. The balance of the amount under this formula due December 31, 2018 for calendar year 2017 is approximately $20 million, which was paid to 4CA on December 14, 2018. The balance of the amount under this formula at December 31, 2018 for calendar year 2018 (up to the date that NTEC purchased the 7% interest) is approximately $10 million, which is due to 4CA at December 31, 2019.

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 commodity contract collateral obligations and other transactions. As of December 31, 2018, standby letters of credit totaled $0.2 million and will expire in 2019. As of December 31, 2018, surety bonds expiring through 2019 totaled $17 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at December 31, 2018. Since July 6, 2016, Pinnacle West has issued five parental guarantees for 4CA relating to payment obligations arising from 4CA’s acquisition of El Paso’s 7% interest in Four Corners, and pursuant to the Four Corners participation agreement payment obligations arising from 4CA’s ownership interest in Four Corners, four of which terminated following the sale of 4CA's 7% interest to NTEC. (See "Four Corners Coal Supply Agreement - 4CA Matter" above for information related to this sale.)

In connection with the sale of 4CA's 7% interest to NTEC, Pinnacle West is guaranteeing certain obligations that NTEC will have to the other owners of Four Corners. (See "Four Corners Coal Supply Agreement - 4CA Matter" above for information related to this guarantee.) A maximum obligation is not explicitly stated in the guarantee and, therefore, the overall maximum amount of the obligation under such guarantee cannot be reasonably estimated; however, we consider the fair value of this guarantee to be immaterial.

11. Asset Retirement Obligations

In 2018, APS recognized an ARO for the removal of hazardous waste containing solar panels at all of our utility scale solar plants, which resulted in an increase to the ARO in the amount of $14 million. In addition, due to the sale of 4CA assets to NTEC in 2018 (see Note 10 for more information on 4CA matters) there was a decrease to the ARO of $9 million. APS recognized an ARO of $7 million for rooftop solar removals in accordance with the obligations included in the customer contracts, which requires APS to remove the panels at the end of the contract life and includes the costs for the disposal of hazardous materials in accordance with environmental regulations. Finally, APS has other ARO adjustments resulting in a net decrease of $1 million.

In 2017, APS received a new decommissioning study for the Navajo Plant. This resulted in an increase to the ARO in the amount of $22 million, an increase in regulatory asset of $2 million and a reduction of the regulatory liability of $20 million.

The following table shows the change in our asset retirement obligations for 2018 and 2017 (dollars in thousands):

	2018	2017
Asset retirement obligations at the beginning of year	$679,529	$624,475
Changes attributable to:		
Accretion expense	36,876	33,104
Settlements	(9,726)	—
Estimated cash flow revisions	2,002	21,950
Newly incurred or acquired obligations	17,864	—
Asset retirement obligations at the end of year	$726,545	$679,529

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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. Selected Quarterly Financial Data (Unaudited)

Consolidated quarterly financial information for 2018 and 2017 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.

	2018 Quarter Ended				2018
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$692,714	$974,123	$1,268,034	$756,376	$3,691,247
Operations and maintenance	265,682	268,397	246,545	256,120	1,036,744
Operating income	31,334	242,162	433,307	66,884	773,687
Income taxes	(1,265)	44,039	84,333	6,795	133,902
Net income	8,094	171,612	319,885	30,949	530,540
Net income attributable to common shareholders	3,221	166,738	315,012	26,076	511,047
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$0.03	$1.49	$2.81	$0.23	$4.56
Net income attributable to common shareholders — Diluted	0.03	1.48	2.80	0.23	4.54

	2017 Quarter Ended				2017
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$677,728	$944,587	$1,183,322	$759,659	$3,565,296
Operations and maintenance	226,071	220,985	230,839	271,212	949,107
Operating income	67,411	297,257	459,548	85,547	909,763
Income taxes	4,211	88,967	144,319	20,775	258,272
Net income	28,185	172,317	280,945	26,502	507,949
Net income attributable to common shareholders	23,312	167,443	276,072	21,629	488,456
Earnings Per Share:					
Net income attributable to common shareholders — Basic	$0.21	$1.50	$2.47	$0.19	$4.37
Net income attributable to common shareholders — Diluted	0.21	1.49	2.46	0.19	4.35

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Selected Quarterly Financial Data (Unaudited) - APS

APS's quarterly financial information for 2018 and 2017 is as follows (dollars in thousands):

	2018 Quarter Ended				2018
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$692,006	$971,963	$1,267,997	$756,376	$3,688,342
Operations and maintenance	254,601	251,999	226,346	236,281	969,227
Operating income	37,878	251,590	453,547	86,753	829,768
Net income attributable to common shareholder	9,599	177,825	338,366	44,475	570,265

	2017 Quarter Ended				2017
	March 31,	June 30,	September 30,	December 31,	Total
Operating revenues	$677,589	$943,406	$1,178,846	$757,811	$3,557,652
Operations and maintenance	219,008	215,775	222,374	260,826	917,983
Operating income	70,269	296,700	465,658	91,912	924,539
Net income attributable to common shareholder	23,162	169,108	284,256	27,783	504,309

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.

Level 2 — Other significant observable inputs, including 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).

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 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

Certain instruments have been valued using the concept of Net Asset Value ("NAV"), as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, their NAV is generally not published and publicly available, nor are these instruments traded on an exchange. Instruments valued using NAV, as a practical expedient are included in our fair value disclosures however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to cash equivalents, derivative instruments, and investments held in the nuclear decommissioning trust and other special use funds. On an annual basis we apply fair value measurements to plan assets held in our retirement and other benefit plans. See Note 7 for fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

Cash equivalents represent certain investments in 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.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 Nuclear Decommissioning Trust and Other Special Use Funds

The nuclear decommissioning trust and other special use funds invest in fixed income and equity securities. Other special use funds include the coal reclamation escrow account and the active union medical trust. See Note 19 for additional discussion about our investment accounts.

We value investments in fixed income and equity securities using information provided by our trustees and escrow agent. Our trustees and escrow agent use pricing services that utilize the valuation methodologies described below 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 trustees' and escrow agent's internal operating controls and valuation processes.

Fixed Income Securities

Fixed income securities issued by the U.S. Treasury 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 fixed income 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.

Fixed income securities may also include short-term investments in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, commercial paper, and other short term instruments. These instruments are valued using active market prices or utilizing observable inputs described above.

Equity Securities

The nuclear decommissioning trust's equity security investments are held indirectly through commingled funds. The commingled funds are valued using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. 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 funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The nuclear decommissioning trust and other special use funds may also hold equity securities that include exchange traded mutual funds and money market accounts for short-term liquidity purposes. These short-term, highly-liquid, investments are valued using active market prices.

Fair Value Tables

The following table presents the fair value at December 31, 2018 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 (Level 3)	Other		Balance at December 31, 2018
Assets						
Cash equivalents	$ 1,200	$—	$ —	$—		$ 1,200
Risk management activities — derivative instruments:						
Commodity contracts	—	3,140	2	(2,029)	(a)	1,113
Nuclear decommissioning trust:						
Equity securities	5,203	—	—	2,148	(b)	7,351
U.S. commingled equity funds	—	—	—	396,805	(c)	396,805
U.S. Treasury debt	148,173	—	—	—		148,173
Corporate debt	—	96,656	—	—		96,656
Mortgage-backed debt securities	—	113,115	—	—		113,115
Municipal bonds	—	79,073	—	—		79,073
Other fixed income	—	9,961	—	—		9,961
Subtotal nuclear decommissioning trust	153,376	298,805	—	398,953		851,134
Other special use funds:						
Equity securities	45,130	—	—	593	(b)	45,723
U.S. Treasury debt	173,310	—	—	—		173,310
Municipal bonds	—	17,068	—	—		17,068
Subtotal other special use funds	218,440	17,068	—	593		236,101
Total Assets	$ 373,016	$ 319,013	$ 2	$ 397,517		$ 1,089,548
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (52,696)	$ (8,216)	$ 875	(a)	$ (60,037)

(a) Represents counterparty netting, margin, and collateral. See Note 16.
(b) Represents net pending securities sales and purchases.
(c)

Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2017 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, 2017
Assets						
Cash equivalents	$ 10,630	$—	$—	$—		$ 10,630
Risk management activities — derivative instruments:						
Commodity contracts	—	5,683	1,036	(4,737)	(b)	1,982
Nuclear decommissioning trust:						
Cash and cash equivalents	7,224	—	—	109	(d)	7,333
U.S. commingled equity funds	—	—	—	417,390	(e)	417,390
U.S. Treasury debt	127,662	—	—	—		127,662
Corporate debt	—	114,007	—	—		114,007
Mortgage-backed debt securities	—	111,874	—	—		111,874
Municipal bonds	—	79,049	—	—		79,049
Other fixed income	—	13,685	—	—		13,685
Subtotal nuclear decommissioning trust	134,886	318,615	—	417,499		871,000
Other special use funds (c):	455	31,562	—	525		32,542
Total Assets	$ 145,971	$355,860	$1,036	$413,287		$916,154
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$(78,646)	$(19,292)	$1,516	(b)	$(96,422)

(a) Primarily consists of long-dated electricity contracts.
(b) Represents counterparty netting, margin, and collateral. See Note 16.
(c) Primarily consists of fixed income municipal bonds. Presented as coal reclamation escrow in 2017.
(d) Represents nuclear decommissioning trust net pending securities sales and purchases.
(e) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 3).

Because our forward commodity contracts classified as Level 3 are currently in a net purchase position, we would expect price increases of the underlying commodity to result in increases in the net fair value of the

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

related contracts. Conversely, if the price of the underlying commodity decreases, the net fair value of the related contracts would likely decrease.

Other unobservable valuation inputs include credit and liquidity reserves which do not have a material impact on our valuations; however, significant changes in these inputs could also result in higher or lower fair value measurements.

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at December 31, 2018 and December 31, 2017:

	December 31, 2018 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input	Range	Weighted-Average
Commodity Contracts	**Assets**	**Liabilities**				
Electricity:						
Forward Contracts (a)	$—	$2,456	Discounted cash flows	Electricity forward price (per MWh)	$17.88 - $37.03	$ 26.10
Natural Gas:						
Forward Contracts (a)	2	5,760	Discounted cash flows	Natural gas forward price (per MMBtu)	$1.79 - $2.92	$ 2.48
Total	$2	$8,216				

(a) Includes swaps and physical and financial contracts.

	December 31, 2017 Fair Value (thousands)		Valuation Technique	Significant Unobservable Input	Range	Weighted-Average
Commodity Contracts	**Assets**	**Liabilities**				
Electricity:						
Forward Contracts (a)	$21	$15,485	Discounted cash flows	Electricity forward price (per MWh)	$18.51 - $38.75	$ 27.89
Natural Gas:						
Forward Contracts (a)	1,015	3,807	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.33 - $3.11	$ 2.71
Total	$1,036	$19,292				

(a) Includes swaps and physical and financial contracts.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the years ended December 31, 2018 and 2017 (dollars in thousands):

Commodity Contracts	Year Ended December 31, 2018	2017
Net derivative balance at beginning of period	$(18,256)	$(47,406)
Total net gains (losses) realized/unrealized:		
Included in earnings	—	—
Included in OCI	—	3
Deferred as a regulatory asset or liability	(1,130)	(13,643)
Settlements	(787)	5,834
Transfers into Level 3 from Level 2	(12,830)	(10,026)
Transfers from Level 3 into Level 2	24,789	46,982
Net derivative balance at end of period	$(8,214)	$(18,256)
Net unrealized gains included in earnings related to instruments still held at end of period	$—	$—

Transfers between levels in the fair value hierarchy shown in the table above reflect the fair market value at the beginning of the period and are triggered by a change in the lowest significant input as of the end of the period. We had no significant Level 1 transfers to or from any other hierarchy level. Transfers in or out of Level 3 are typically related to our long-dated energy transactions that extend beyond available quoted periods.

Financial Instruments Not Carried at Fair Value

The carrying value of our short-term borrowings approximate fair value and are classified within Level 2 of the fair value hierarchy. See Note 6 for our long-term debt fair values. The NTEC note receivable related to the sale of 4CA's interest in Four Corners bears interest at 3.9% per annum and has a book value of $61 million as of December 31, 2018, as presented on the Consolidated Balance Sheets. The carrying amount is not materially different from the fair value of the note receivable and is classified within Level 3 of the fair value hierarchy. See Note 10 for more information on 4CA matters.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

14. Earnings Per Share