

PINNACLE WEST CAPITAL CORP  
 Form 10-K  
 February 20, 2015  
Table of Contents

UNITED STATES  
 SECURITIES AND EXCHANGE COMMISSION  
 WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

OR

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

For the transition period from	to	
Commission File Number	Registrants; State of Incorporation; Addresses; and Telephone Number	IRS Employer Identification No.
	PINNACLE WEST CAPITAL CORPORATION (An Arizona corporation)	
1-8962	400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0512431
	ARIZONA PUBLIC SERVICE COMPANY (An Arizona corporation)	
1-4473	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  No

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ARIZONA PUBLIC SERVICE COMPANY Yes  No

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  No

ARIZONA PUBLIC SERVICE COMPANY Yes  No

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  No

ARIZONA PUBLIC SERVICE COMPANY Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PINNACLE WEST CAPITAL CORPORATION Yes  No

ARIZONA PUBLIC SERVICE COMPANY Yes  No

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

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

PINNACLE WEST CAPITAL CORPORATION

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

(Do not check if a smaller reporting company)

ARIZONA PUBLIC SERVICE COMPANY

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

(Do not check if a smaller reporting company)

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

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

PINNACLE WEST CAPITAL CORPORATION \$6,356,930,539 as of June 30, 2014

ARIZONA PUBLIC SERVICE COMPANY \$0 as of June 30, 2014

The number of shares outstanding of each registrant's common stock as of February 13, 2015

PINNACLE WEST CAPITAL CORPORATION 110,575,187 shares

Common Stock, \$2.50 par value, 71,264,947 shares.

ARIZONA PUBLIC SERVICE COMPANY

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 20, 2015 are incorporated by reference into Part III hereof.

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

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Table of Contents

## TABLE OF CONTENTS

	Page
<u>GLOSSARY OF NAMES AND TECHNICAL TERMS</u>	<u>ii</u>
<u>FORWARD-LOOKING STATEMENTS</u>	<u>2</u>
<u>PART I</u>	<u>3</u>
<u>Item 1. Business</u>	<u>3</u>
<u>Item 1A. Risk Factors</u>	<u>26</u>
<u>Item 1B. Unresolved Staff Comments</u>	<u>37</u>
<u>Item 2. Properties</u>	<u>38</u>
<u>Item 3. Legal Proceedings</u>	<u>41</u>
<u>Item 4. Mine Safety Disclosures</u>	<u>41</u>
<u>Executive Officers of Pinnacle West</u>	<u>42</u>
<u>PART II</u>	<u>43</u>
<u>Item 5. Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities</u>	<u>43</u>
<u>Item 6. Selected Financial Data</u>	<u>45</u>
<u>Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	<u>47</u>
<u>Item 7A. Quantitative and Qualitative Disclosures About Market Risk</u>	<u>71</u>
<u>Item 8. Financial Statements and Supplementary Data</u>	<u>72</u>
<u>Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</u>	<u>164</u>
<u>Item 9A. Controls and Procedures</u>	<u>164</u>
<u>Item 9B. Other Information</u>	<u>165</u>
<u>PART III</u>	<u>165</u>
<u>Item 10. Directors, Executive Officers and Corporate Governance of Pinnacle West</u>	<u>165</u>
<u>Item 11. Executive Compensation</u>	<u>165</u>
<u>Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters</u>	<u>165</u>
<u>Item 13. Certain Relationships and Related Transactions, and Director Independence</u>	<u>166</u>
<u>Item 14. Principal Accountant Fees and Services</u>	<u>167</u>
<u>PART IV</u>	<u>168</u>
<u>Item 15. Exhibits and Financial Statement Schedules</u>	<u>168</u>
<u>SIGNATURES</u>	<u>188</u>

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



Table of Contents

## GLOSSARY OF NAMES AND TECHNICAL TERMS

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

TCA  
VIE

Transmission cost adjustor  
Variable interest entity

ii

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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” and other similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from outcomes currently expected or sought by Pinnacle West or APS. In addition to the Risk Factors described in Item 1A and in Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” these factors include, but are not limited to:

- our ability to manage capital expenditures and operations and maintenance costs while maintaining reliability and customer service levels;
- variations in demand for electricity, including those due to weather, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation or regulation, including those relating to environmental requirements, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on debt and equity capital;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, particularly in real estate markets;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental and other concerns surrounding coal-fired generation;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and ACC orders.

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



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 and BCE. Additional information related to these subsidiaries is provided later in this report.

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

BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY

APS currently provides electric service to approximately 1.2 million customers. We own or lease 6,426 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2014, no single purchaser or user of energy accounted for more than 1.4% 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.

4

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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 during 2014 were as follows:

Generation Facilities

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

Coal-Fueled Generating Facilities

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

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

Table of Contents

In connection with APS's most recent retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of \$57.1 million on an annual basis.

Concurrently with the closing of the SCE transaction, BHP Billiton, the parent company of BNCC, the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton will be retained by NTEC under contract as the mine manager and operator until July 2016. Also occurring concurrently with the closing, the Four Corners' co-owners executed a long-term agreement for the supply of coal to Four Corners from July 2016, when the current coal supply agreement expires, through 2031 (the "2016 Coal Supply Agreement"). El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS has agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. The cash purchase price, which will be subject to certain adjustments at closing, is immaterial in amount, and the purchaser will assume El Paso's reclamation and decommissioning obligations associated with the 7% interest. Completion of the purchase is subject to the receipt of certain regulatory approvals and is expected to occur in July 2016.

When APS, or an affiliate of APS, ultimately acquires El Paso's interest in Four Corners, NTEC will have an option to purchase the interest within a certain timeframe pursuant to an option granted by APS to NTEC. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not exercise its option.

The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also requires the approval of the DOI, as does a related federal rights-of-way grant, which the Four Corners participants are pursuing. A federal environmental review is underway as part of the DOI review process. In March 2014, APS received a draft of the environmental impact statement ("DEIS") in connection with the DOI review process. As a proponent of Four Corners and the Navajo Mine Energy Project, APS, along with other members of the public, submitted comments on the DEIS. APS cannot predict whether these federal approvals will be granted and, if so, on a timely basis, or whether any conditions that may be attached to them will be acceptable to the Four Corners owners. On December 19, 2014, APS obtained a Prevention of Significant Deterioration ("PSD") permit from EPA allowing APS to install selective catalytic reduction ("SCR") control technology at Four Corners, as described below under "Environmental Matters — EPA Environmental Regulation."

Cholla — Cholla is a 4-unit coal-fired power plant located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4, and APS operates that unit for PacifiCorp. APS has a total entitlement from Cholla of 647 MW. APS purchases all of Cholla's coal requirements from a coal supplier that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. The Cholla coal contract runs through 2024. In addition, APS has a long-term coal transportation contract that runs through 2017 with plans to extend the contract beyond 2017. See "Current and Future Resources - Future Resources and Resource Plan" below for a discussion of future plans for Cholla.

## Table of Contents

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

These coal-fueled plants face uncertainties, including those related to existing and potential legislation and regulation, that could significantly impact their economics and operations. See "Environmental Matters" below and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview and Capital Expenditures" in Item 7 for developments impacting these coal-fueled facilities. See Note 10 for information regarding APS's coal mine reclamation obligations.

### Nuclear

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

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 agreements expire at the end of 2015 and contain options to renew the leases or to purchase the property for fair market value at the end of the lease terms. On July 7, 2014, APS notified the lessor trust entities of APS's intent to exercise the fixed rate lease renewal options. The length of the renewal options will result in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors. See Note 18 for additional information regarding the Palo Verde Unit 2 sale leaseback transactions.

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

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

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

The Palo Verde participants have contracted for 100% of Palo Verde's requirements for uranium concentrates and conversion services through 2018 and 45% of its requirements in 2019-2020. The

Table of Contents

participants have also contracted for 100% of Palo Verde's enrichment services through 2020; and all of Palo Verde's fuel assembly fabrication services through 2022.

**Spent Nuclear Fuel and Waste Disposal** — The Nuclear Waste Policy Act of 1982 (“NWPA”) required the DOE to accept, transport, and dispose of spent nuclear fuel and high level waste generated by the nation's nuclear power plants by 1998. The DOE's obligations are reflected in a contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (the “Standard Contract”) with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. APS is directly and indirectly involved in several legal proceedings related to DOE's failure to meet its statutory and contractual obligations regarding acceptance of spent nuclear fuel and high level waste.

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

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE. This lawsuit sought to recover damages incurred due to DOE's failure to accept Palo Verde's spent nuclear fuel for the period beginning January 1, 2007 through June 30, 2011. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of \$57.4 million by DOE to the Palo Verde owners for certain specified 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 regulatory liability and had no impact on current income.

**The One-Mill Fee** — In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged DOE's 2010 determination of the adequacy of the one tenth of a cent per kWh fee (the “one-mill fee”) paid by the nation's commercial nuclear power plant owners pursuant to their individual obligations under the Standard Contract. This fee is recovered by APS in its retail rates. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the “D.C. Circuit”) held that DOE failed to conduct a sufficient fee analysis in making the 2010 determination. The D.C. Circuit remanded the 2010 determination to the Secretary of the DOE (“Secretary”) with instructions to conduct a new fee adequacy determination within six months. In February 2013, upon completion of DOE's revised one-mill fee adequacy determination, the D.C. Circuit reopened the proceedings. On November 19, 2013, the D.C. Circuit ordered the Secretary to notify Congress of his intent to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators, as he is required to do pursuant to the NWPA and the D.C. Circuit's order. On January 3, 2014, the Secretary notified Congress of his intention to suspend collection of the one-mill fee, subject to Congress' disapproval. On May 16, 2014, the DOE notified all commercial nuclear power plant operators who are party to a Standard Contract that it reduced the one-mill fee to zero, thus effectively terminating the one-mill fee.

**DOE's Construction Authorization Application for Yucca Mountain** — The DOE had planned to meet its NWPA and Standard Contract disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In June 2008, the DOE submitted its Yucca Mountain construction authorization application to the NRC, but in March 2010, the DOE filed a motion to dismiss with prejudice the Yucca Mountain construction authorization application. Several interested parties have also intervened in the NRC proceeding. Additionally, a number of interested parties filed a variety of lawsuits in different jurisdictions around the country challenging the DOE's authority to withdraw the Yucca Mountain construction authorization application and NRC's cessation of its review of the Yucca Mountain



Table of Contents

construction authorization application. The cases have been consolidated into one matter at the D.C. Circuit. In August 2013, the D.C. Circuit ordered the NRC to resume its review of the application with available appropriated funds.

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

On December 18, 2014, the NRC issued Volume 4 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume covers administrative and programmatic requirements for the repository. It documents the staff's evaluation of whether the DOE's research and development and performance confirmation programs, as well as other administrative controls and systems, meet applicable NRC requirements. Volume 4 contains the staff's finding that most administrative and programmatic requirements in NRC regulations are met, except for certain requirements relating to ownership of land and water rights.

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

Waste Confidence — On June 8, 2012, the D.C. Circuit issued its decision on a challenge by several states and environmental groups of the NRC's rulemaking regarding temporary storage and permanent disposal of high level nuclear waste and spent nuclear fuel. The petitioners had challenged the NRC's 2010 update to the agency's Waste Confidence Decision and temporary storage rule ("Waste Confidence Decision").

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

On September 6, 2012, the NRC Commissioners issued a directive to the NRC staff to proceed directly with development of a generic environmental impact statement to support an updated Waste Confidence Decision. The NRC Commissioners also directed the staff to establish a schedule to publish a final rule and environmental impact study within 24 months of September 6, 2012.

In September 2013, the NRC issued its draft Generic Environmental Impact Statement ("GEIS") to support an updated Waste Confidence Decision. On August 26, 2014, the NRC approved a final rule on the environmental effects of continued storage of spent nuclear fuel. The continued storage rule adopted the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations. As a result, those generic impacts do not need to be re-analyzed in the environmental reviews for individual licenses. Although Palo Verde had not been involved in any licensing actions affected by the D.C. Circuit's June 8, 2012, decision, the NRC lifted its suspension on final licensing actions on all nuclear power plant licenses and renewals that went into effect when the D.C. Circuit issued its June 2012 decision. The August 26th final rule has been subject to continuing legal challenges before the NRC and the Court of Appeals.





## Table of Contents

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

**Nuclear Decommissioning Costs** — APS currently relies on an external sinking fund mechanism to meet the NRC financial assurance requirements for decommissioning its interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in APS’s ACC jurisdictional rates. Decommissioning costs are recoverable through a non-bypassable system benefits charge (paid by all retail customers taking service from the APS system). See Note 19 for additional information about APS’s nuclear decommissioning trusts.

**Palo Verde Liability and Insurance Matters** — See “Palo Verde Nuclear Generating Station — Nuclear Insurance” in Note 10 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde.

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

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

The NRC has issued a number of guidance documents regarding implementation of these requirements. Due to the developing nature of these requirements, we cannot predict the ultimate financial or operational impacts on Palo Verde or APS. However, to implement these recommendations, Palo Verde expects to spend approximately \$40 million for capital enhancements to the plant over the next two years in addition to the approximate \$80 million that has already been spent on capital enhancements as of December 31, 2014 (APS’s share is 29.1%).

### **Natural Gas and Oil Fueled Generating Facilities**

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



Table of Contents

Ocotillo is a 330 MW 4-unit gas plant. 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 for summer 2018. The last milestone before construction begins was raised during the ACC's Integrated Resource Planning meeting in the fall of 2014. While there was support for the first 2 units which replace the existing steam units, questions were raised on the cost effectiveness for the additional three units. To address these matters, APS issued a request for proposal in late January 2015 for the incremental capacity, equivalent to 3 of the 5 units.

Solar Facilities

To date, APS has begun operation of 150 MW of utility scale solar through its AZ Sun Program, discussed below. These facilities are owned by APS and are located in multiple locations throughout Arizona.

Additionally, APS owns and operates more than forty small solar systems around the state. Together they have the capacity to produce approximately 4 MW of renewable energy. This fleet of solar systems includes a 3 MW facility located at the Prescott Airport and 1 MW of small solar in various locations across Arizona. APS has also developed solar photovoltaic distributed energy systems installed as part of the Community Power Project in Flagstaff, Arizona. The Community Power Project, approved by the ACC on April 1, 2010, is a pilot program through which APS owns, operates and receives energy from approximately 1 MW of solar photovoltaic distributed energy systems located within a certain test area in Flagstaff, Arizona. Additionally, APS owns 12 MW of solar photovoltaic systems installed across Arizona through the ACC-approved Schools and Government Program.

In December 2014, the ACC voted that it had no objection to APS implementing a 10 MWdc (approximately 8.5 MWac) residential rooftop program. The first stage of the residential rooftop solar program is to be 8 MW followed by a 2 MW second stage that will only be deployed if coupled with distributed storage. Under this program, APS will own, operate and maintain approximately 1,500 residential systems. The program will target specific distribution feeders in an effort to maximize potential system benefits, as well as make systems available to limited-income customers who cannot easily install solar through transactions with third parties.

Purchased Power Contracts

In addition to its own available generating capacity, APS purchases electricity under various arrangements, including long-term contracts and purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements. A portion of APS's purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. (See Note 16.) APS continually assesses its need for additional capacity resources to assure system reliability.

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

Table of Contents

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

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

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

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

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

#### 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 2014 peak one-hour demand on its electric system was recorded on July 23, 2014 at 7,007 MW, compared to the 2013 peak of 6,927 MW recorded on July 8, 2013. APS’s reserve margin at the time of the 2014 peak demand, calculated using system load serving capacity, was 34%. Excluding certain contractual rights to call on additional capacity on short notice, which APS may use in the event of unusual weather or unplanned outages, the 2014 reserve margin was 24%. APS anticipates the reserve margin for 2015 will be approximately 33% or 23% excluding contractual rights to call on additional capacity. APS expects that our reserve margins will decrease over the next three years and that additional conventional resources will be needed around 2017.

##### Future Resources and Resource Plan

Under the ACC’s resource planning rule, APS will file by April 1 of each even-numbered year its resource plans for the next fifteen-year period. The rule requires the ACC to issue an order with its acknowledgment of APS’s resource plan within approximately ten months following its submittal. The ACC’s acknowledgment of APS’s resource plan will consider factors such as the total cost of electric energy services, demand management, analysis of supply-side options, system reliability and risk management. APS filed its 2014 resource plan on April 1, 2014 and it will be filing its next resource plan by April 1, 2016. The ACC staff is exploring potential ways to improve the resource plan process.

After considering the costs to comply with environmental regulations, on September 11, 2014, APS announced that it will close Cholla Unit 2 by April 2016 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. APS filed an amendment to its resource plan with the ACC to request approval of the retirement of Cholla Unit 2. The ACC has not yet made a decision on this amendment. Previously, APS estimated Cholla Unit 2’s end of life to be 2033. APS is currently recovering



Table of Contents

depreciation and a return on the net book value of the unit in base rates and plans to seek recovery of all of the unit's retirement-related costs in its next retail rate case. If APS closes Cholla Unit 2, APS believes it will be allowed recovery of the remaining net book value of Unit 2 (\$128 million as of December 31, 2014), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

**Renewable Energy Standard**

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

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

**Renewable Energy Portfolio.** To date, APS has a diverse portfolio of existing and planned renewable resources totaling 1,253 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 1,194 MW are currently in operation and 59 MW are under contract for development or are under construction. Renewable resources in operation include 169 MW of facilities owned by APS, 629 MW of long-term purchased power agreements, and an estimated 396 MW of customer-sited, third-party owned distributed energy resources.

APS's strategy to achieve its RES requirements includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS. APS is developing owned solar resources through the AZ Sun Program. Under this program to date, APS estimates its investment commitment will be approximately \$674 million. See Note 3 for additional details about the AZ Sun Program.

Table of Contents

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

	Location	Actual/ Target Commercial Operation Date	Term (Years)	Net Capacity In Operation (MW AC)	Net Capacity Planned/Under Development (MW AC)
APS Owned					
Solar:					
AZ Sun Program:					
Paloma	Gila Bend, AZ	2011		17	
Cotton Center	Gila Bend, AZ	2011		17	
Hyder Phase 1	Hyder, AZ	2011		11	
Hyder Phase 2	Hyder, AZ	2012		5	
Chino Valley	Chino Valley, AZ	2012		19	
Hyder II	Hyder, AZ	2013		14	
Foothills	Yuma, AZ	2013		35	
Gila Bend	Gila Bend, AZ	2014		32	
Luke AFB	Glendale, AZ	2015			10
City of Phoenix	Buckeye, AZ	2015			10
Subtotal AZ Sun Program				150	20
Multiple Facilities	AZ	Various		4	
Distributed Energy:					
APS Owned (a)	AZ	Various		15	9
Total APS Owned				169	29
Purchased Power Agreements					
Solar:					
Solana	Gila Bend, AZ	2013	30	250	
RE Ajo	Ajo, AZ	2011	25	5	
Sun E AZ 1	Prescott, AZ	2011	30	10	
Saddle Mountain	Tonopah, AZ	2012	30	15	
Badger	Tonopah, AZ	2013	30	15	
Gillespie	Maricopa County, AZ	2013	30	15	
Wind:					
Aragonne Mesa	Santa Rosa, NM	2006	20	90	
High Lonesome	Mountainair, NM	2009	30	100	
Perrin Ranch Wind	Williams, AZ	2012	25	99	
Geothermal:					
Salton Sea	Imperial County, CA	2006	23	10	
Biomass:					
Snowflake	Snowflake, AZ	2008	15	14	
Biogas:					
Glendale Landfill	Glendale, AZ	2010	20	3	
NW Regional Landfill	Surprise, AZ	2012	20	3	
Total Purchased Power Agreements				629	—
Distributed Energy					



Solar (b)					
Third-party Owned	AZ	Various		363	30
Agreement 1	Bagdad, AZ	2011	25	15	
Agreement 2	AZ	2011-2012	20-21	18	
Total Distributed Energy				396	30
Total Renewable Portfolio				1,194	59

## Table of Contents

- (a) Includes Flagstaff Community Power Project, APS School and Government Program and APS Solar Partner Program.
- (b) 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 Energy Efficiency Standard (“EES”) of 22% cumulative annual energy savings by 2020. This standard was adopted and became effective on January 1, 2011. This standard will likely impact Arizona’s future energy resource needs. (See Note 3 for energy efficiency and other demand side management obligations.)

### Government Awards

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

### Competitive Environment and Regulatory Oversight

#### Retail

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

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

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

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



Table of Contents

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

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

On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations was whether various aspects of a deregulated market, including setting utility rates on a "market" basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. The ACC opened a docket on November 4, 2013 to explore technological advances and innovative changes within the electric utility industry. A series of workshops in this docket were held in 2014 and another is currently scheduled for February 26, 2015.

Wholesale

FERC regulates rates for wholesale power sales and transmission services. (See Note 3 for information regarding APS's transmission rates.) During 2014, approximately 7.3% 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.

## Table of Contents

### Environmental Matters

#### Climate Change

**Legislative Initiatives.** There have been no recent attempts by Congress to pass legislation that would regulate greenhouse gas (“GHG”) emissions, and it is unclear if and when the 114<sup>th</sup> Congress will consider a climate change bill. In the event climate change legislation ultimately passes, the actual economic and operational impact of such legislation on APS depends on a variety of factors, none of which can be fully known until a law is enacted and the specifics of the resulting program are established. These factors include the terms of the legislation with regard to allowed GHG emissions; the cost to reduce emissions; in the event a cap-and-trade program is established, whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned (and, if so, the cost of those allowances in the marketplace) and whether offsets and other measures to moderate the costs of compliance will be available; and, in the event of a carbon tax, the amount of the tax per pound of carbon dioxide (“CO<sub>2</sub>”) equivalent emitted.

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

**Regulatory Initiatives.** In 2009, EPA determined that GHG emissions endanger public health and welfare. This determination was made in response to a 2007 United States Supreme Court ruling that GHGs fit within the Clean Air Act’s broad definition of “air pollutant” and, as a result, EPA has the authority to regulate GHG emissions of new motor vehicles under the Clean Air Act. As a result of this “endangerment finding,” EPA determined that the Clean Air Act required new regulatory requirements for new and modified major GHG emitting sources, including power plants. EPA issued a rule under the Clean Air Act, known as the “tailoring rule,” establishing new GHG emission thresholds that determine when sources, including power plants, must obtain air operating permits or New Source Review permits. “New Source Review,” or “NSR,” is a pre-construction permitting program under the Clean Air Act that requires analysis of pollution controls prior to building a new stationary source or making major modifications to an existing stationary source. The tailoring rule became applicable to power plants in January 2011 and, as a result, APS will generally be required to consider the impact of GHG emissions as part of its traditional NSR analysis for new sources and major modifications to existing plants.

Consistent with President Obama’s June 2013 Climate Action Plan addressing his plans to reduce GHG emissions in the United States, pursuant to its endangerment finding and its authority under Section 111(b) of the Clean Air Act, on September 20, 2013, EPA issued a proposed rule, which would establish New Source Performance Standards (“NSPS”) for new fossil-fired power plants. Subsequently, on June 2, 2014, EPA issued two additional 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 January 7, 2015, EPA announced that its carbon pollution standards for new, modified and reconstructed, and existing power plants would be finalized in summer 2015.

EPA's proposed rule applicable to modified and reconstructed power plants would require fossil fuel-fired EGUs undergoing modification or reconstruction to meet CO<sub>2</sub> performance standards based on a

17

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## Table of Contents

combination of best operating practices and equipment upgrades. The rule would also require existing EGUs that are modified or reconstructed after becoming subject to state or federal standards of performance for existing power plants under Section 111(d) of the Clean Air Act to continue to meet those requirements. We cannot currently predict the shape of any final rules or standards for modified and reconstructed fossil-fired EGUs or assess how they might potentially impact the Company.

With respect to existing power plants, EPA's proposed "Clean Power Plan" rule proposes state-specific goals or targets to achieve reductions in CO<sub>2</sub> emissions from existing EGUs measured from a 2012 baseline. EPA's proposed emission rates would not apply directly to specific units, but must be met on a state-wide basis. As proposed, each state's goal is an emissions rate, which is a single number for the future carbon intensity of that state. The proposed rule provides guidelines to states to help develop their plans for meeting the interim (2020-2029) and final (2030 and beyond) emission rates set forth in the proposal. States would be required to submit their plans to EPA by summer 2016, although states may be eligible for one- or two-year extensions, provided they submit detailed explanations that contain specified information required by EPA in advance of the applicable due date. EPA's proposal for Arizona would result in in-state coal-fired generation (with the exception of coal-fired generation located in Indian country) shifting to natural gas combined cycle 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. APS will continue to monitor these standards as they are developed.

As for sources in Indian country (which are not subject to state plans), on October 28, 2014, EPA issued a supplemental rule proposing carbon dioxide emission rates for U.S. territories and areas of Indian country with existing fossil fuel-fired EGUs, as well as guidelines for plans to achieve those rates. The supplemental proposal applies to Four Corners and the Navajo Plant, both of which are located on the Navajo Nation. With respect to these two plants, EPA applied the four building blocks described in its June 2, 2014 Clean Air Act Section 111(d) proposal to establish interim and final goals, expressed as CO<sub>2</sub> emission rates. If finalized as proposed, it is unlikely the rule would require additional emission reductions as a result of the plants' past and future actions to comply with the Best Available Retrofit Technology ("BART") requirements of EPA's Clean Air Visibility Rule. (See "EPA Environmental Regulation - Regional Haze Rules" discussion below.)

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

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

## 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,





Table of Contents

including fossil-fired power plants. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis.

The Four Corners and Navajo Plant participants' obligations to comply with EPA's final BART determinations (and Cholla's obligations to comply with ADEQ's and EPA's determinations), coupled with the financial impact of potential future climate change legislation, other environmental regulations, and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to continue their participation in these plants.

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

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA approved ADEQ's BART emissions limits for sulfur dioxide ("SO<sub>2</sub>") and emissions of particulate matter ("PM"), but added a ~~SO~~ removal efficiency requirement of 95%. In addition, EPA disapproved ADEQ's BART determinations for oxides of nitrogen ("NO<sub>x</sub>") and promulgated a Federal Implementation Plan ("FIP") establishing a new, more stringent "bubbled" NO<sub>x</sub> emission rate applicable to the two BART-eligible Cholla units owned by APS and the other BART-eligible unit owned by PacifiCorp. In order to comply with this new rate, APS will be required to install SCR control technology on all three of the BART-eligible Cholla units. APS's total costs for these post-combustion NO<sub>x</sub> controls would be approximately \$200 million. This amount is not included in our current estimates for environmental capital expenditures in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Expenditures" in Item 7. Under the FIP, APS has five years from December 2012 to complete installation of the equipment and achieve the BART emission limit for NO<sub>x</sub>.

APS believes that EPA's final rule as it applies to Cholla is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014, and the court scheduled oral argument for March 9, 2015.

In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 by April 2016 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 to reduce regional haze is unlikely to be required in the future because retiring and converting the units as contemplated in the proposal is more cost-effective than, and will result in increased visibility improvement over, the current BART requirements for NO<sub>x</sub> imposed on the Cholla units under EPA's BART FIP. Because APS's proposal involves state and federal rule-making processes, APS is unable to predict when or whether it may ultimately be approved.

Four Corners. On August 6, 2012, EPA issued its final BART determination for Four Corners, which requires APS to install and operate SCR control technology on Units 4 and 5 by July 31, 2018. (APS retired Four Corners Units 1-3 on December 30, 2013.) APS estimates that its 63% share of the cost of these controls for Four Corners Units 4 and 5 would be at least \$350 million. APS expects to incur certain of these costs during the 2015 through 2017 timeframe, which are included in our capital expenditure estimates. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Expenditures" in Item 7 for such estimates and for a discussion of the capital expenditures related to the



Table of Contents

agreement to purchase El Paso's 7% interest in Units 4 and 5.) For PM emissions, EPA is requiring Units 4 and 5 to meet an emission limit of 0.015 lb/MMBtu and a 20 percent opacity limit, both of which are achievable through operation of Four Corners' existing baghouses. Although unrelated to BART, the final BART rule also imposes a 20 percent opacity limitation on certain fugitive dust emissions from Four Corners' coal and material handling operations. Navajo Plant. On January 18, 2013, EPA issued a proposed BART rule for the Navajo Plant, which would require installation of SCR technology in order to achieve a new, more stringent plant-wide NO<sub>x</sub> emission limit. In addition, EPA proposed a "better than BART" alternative and solicited comment on other options that could set longer time frames for installing pollution controls if the Navajo Plant can achieve additional emission reductions. On July 26, 2013, a group of stakeholders, including SRP, the operating agent for the Navajo Plant, submitted to EPA two suggested alternatives to BART, which would achieve greater NO<sub>x</sub> emission reductions and result in greater reasonable progress toward the national visibility goal than EPA's proposed BART determination. On July 28, 2014, EPA issued a final Navajo Plant BART rule approving the alternative stakeholder plan. Depending on which alternate operating scenario the Navajo Plant participants ultimately select, the required NO<sub>x</sub> emission reductions could be achieved by either closing one of the three 750 MW units at the plant or curtailing energy production across all three units, such that the emission reductions are commensurate with the closure of approximately one of the Navajo Plant units. APS estimates that its share of costs for upgrades at the Navajo Plant could be up to approximately \$200 million. These costs are not included in the capital expenditure estimates described in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Expenditures" in Item 7 since the majority of such costs are expected to be incurred after 2017. In October 2014, a coalition of environmental groups, an Indian tribe, and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this petition.

Mercury and other Hazardous Air Pollutants. On December 16, 2011, EPA issued the final Mercury and Air Toxics Standards ("MATS") rule, which established maximum achievable control technology ("MACT") standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired power plants. Generally, plants will have three years after the effective date of the rule to achieve compliance. In the case of Cholla and Four Corners, APS will have until April 16, 2016, or a total of four years after the MATS rule's effective date, to comply with the new MACT standards because the respective permitting authorities granted APS's requests for one-year compliance date extensions. Similarly, SRP will have until April 16, 2016 to comply with MATS at the Navajo Plant, as a result of a one-year extension granted by EPA and the Navajo Nation EPA.

The MATS rule will require APS to install additional pollution control equipment. APS has installed certain of the equipment necessary to meet the anticipated standards. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately \$130 million for Cholla, which would be avoided if EPA approves APS's compromise proposal discussed under "Regional Haze Rules - Cholla" above. These costs are not included in the capital expenditure estimates described in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Expenditures" in Item 7. No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, is still evaluating compliance options under the rules.

Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of coal combustion residuals ("CCR"), such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and Internet posting requirements. The rule generally requires any existing unlined CCR surface



Table of Contents

impoundment that is contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity.

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

APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately \$15 million, and its share of incremental costs for Cholla is approximately \$85 million. APS expects to incur certain of these costs during the 2015-2017 timeframe, which are included in the capital expenditure estimates in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Expenditures" in Item 7. The amount for Cholla contemplates the closure of Unit 2 in 2016. (See "EPA Environmental Regulation - Regional Haze Rules - Cholla" discussion above.) The Navajo Plant currently disposes of CCR in a dry landfill storage area. At this time, SRP, the operating agent for the Navajo Plant, is analyzing the operations that would be covered by the rule and any resulting compliance costs.

**Effluent Limitation Guidelines.** On April 19, 2013, EPA proposed revised effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil-fired EGUs. EPA's proposal offers numerous options (four of which are "preferred alternatives") that target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and non-chemical metal cleaning wastes operations. The preferred alternatives differ with respect to the scope of requirements that would be applicable to existing discharges of pollutants found in wastestreams generated at existing power plants. All four alternatives would establish a "zero discharge" effluent limit for all pollutants in fly ash transport water. However, requirements governing bottom ash transport water differ depending on which alternative EPA ultimately chooses and could range from effluent limits based on Best Available Technology Economically Achievable to "zero discharge" effluent limits. Depending on which alternative EPA finalizes, Four Corners may be required to change equipment and operating practices affecting boilers and ash handling systems, as well as change its waste disposal techniques. We cannot currently predict the shape of EPA's final rule or wh