PINNACLE WEST CAPITAL CORP
Form 10-Q
October 30, 2015

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2015

OR

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

For the transition period from to

Commission File Number	Exact Name of Each Registrant as specified in its charter; State of Incorporation; Address; 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

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

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

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

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

Indicate by check mark 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.

PINNACLE WEST CAPITAL CORPORATION

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

ARIZONA PUBLIC SERVICE COMPANY

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

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

PINNACLE WEST CAPITAL CORPORATION	Number of shares of common stock, no par value, outstanding as of October 23, 2015: 110,849,752
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of October 23, 2015: 71,264,947

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

TABLE OF CONTENTS

This combined Form 10-Q is separately provided by Pinnacle West Capital Corporation ("Pinnacle West") and Arizona Public Service Company ("APS"). Any use of the words "Company," "we," and "our" refer to Pinnacle West. Each registrant is providing on its own behalf all of the information contained in this Form 10-Q that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is providing 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 1 of this report includes Condensed Consolidated Financial Statements of Pinnacle West and Condensed Consolidated Financial Statements of APS. Item 1 also includes Notes to Pinnacle West's Condensed Consolidated Financial Statements, the majority of which also relate to APS, and Supplemental Notes, which only relate to APS's Condensed Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations. These forward-looking statements are often identified by words such as "estimate," "predict," "may," "believe," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results 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 Part I, Item 1A of the Pinnacle West/APS Annual Report on Form 10-K for the fiscal year ended December 31, 2014 ("2014 Form 10-K"), Part II, Item 1A of this report and in Part I, Item 2 — "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 high 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 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 Arizona Corporation Commission ("ACC") orders.

These and other factors are discussed in the Risk Factors described in Part I, Item 1A of our 2014 Form 10-K and in Part II, 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.

2

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended September 30,	
	2015	2014
OPERATING REVENUES	$1,199,146	$1,172,667
OPERATING EXPENSES		
Fuel and purchased power	363,847	382,361
Operations and maintenance	220,449	223,418
Depreciation and amortization	125,625	103,660
Taxes other than income taxes	43,241	40,850
Other expenses	873	603
Total	754,035	750,892
OPERATING INCOME	445,111	421,775
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	7,645	7,038
Other income (Note 9)	139	2,366
Other expense (Note 9)	(5,538)	(4,193)
Total	2,246	5,211
INTEREST EXPENSE		
Interest charges	49,342	47,626
Allowance for borrowed funds used during construction	(3,518)	(3,479)
Total	45,824	44,147
INCOME BEFORE INCOME TAXES	401,533	382,839
INCOME TAXES	139,555	134,753
NET INCOME	261,978	248,086
Less: Net income attributable to noncontrolling interests (Note 6)	4,862	4,125
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$257,116	$243,961
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	111,036	110,686
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	111,616	111,103
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING		
Net income attributable to common shareholders — basic	$2.32	$2.20
Net income attributable to common shareholders — diluted	$2.30	$2.20

See Notes to Pinnacle West’s Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30, 2015	2014
NET INCOME	$261,978	$248,086
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax benefit of $96 and $58	(151)	(91)
Reclassification of net realized loss, net of tax benefit of $567 and $3,833	892	5,939
Pension and other postretirement benefits activity, net of tax expense of $553 and $3,852	869	5,967
Total other comprehensive income	1,610	11,815
COMPREHENSIVE INCOME	263,588	259,901
Less: Comprehensive income attributable to noncontrolling interests	4,862	4,125
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$258,726	$255,776

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30,	
	2015	2014
OPERATING REVENUES	$2,761,013	$2,765,182
OPERATING EXPENSES		
Fuel and purchased power	868,561	923,001
Operations and maintenance	646,358	647,522
Depreciation and amortization	369,313	310,582
Taxes other than income taxes	129,489	130,699
Other expenses	2,524	2,320
Total	2,016,245	2,014,124
OPERATING INCOME	744,768	751,058
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	26,214	21,979
Other income (Note 9)	549	7,514
Other expense (Note 9)	(12,433)	(9,385)
Total	14,330	20,108
INTEREST EXPENSE		
Interest charges	146,069	152,346
Allowance for borrowed funds used during construction	(12,056)	(11,039)
Total	134,013	141,307
INCOME BEFORE INCOME TAXES	625,085	629,859
INCOME TAXES	214,873	215,698
NET INCOME	410,212	414,161
Less: Net income attributable to noncontrolling interests (Note 6)	14,072	21,976
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$396,140	$392,185
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	110,984	110,579
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	111,490	110,962
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING		
Net income attributable to common shareholders — basic	$3.57	$3.55
Net income attributable to common shareholders — diluted	$3.55	$3.53
DIVIDENDS DECLARED PER SHARE	$1.19	$1.14

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2015	2014
NET INCOME	$410,212	$414,161
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense of $392 and $566	(926)	(472)
Reclassification of net realized loss, net of tax benefit of $1,490 and $6,417	3,742	11,009
Pension and other postretirement benefits activity, net of tax expense of $1,345 and $3,724	1,335	5,114
Total other comprehensive income	4,151	15,651
COMPREHENSIVE INCOME	414,363	429,812
Less: Comprehensive income attributable to noncontrolling interests	14,072	21,976
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$400,291	$407,836

See Notes to Pinnacle West’s Condensed Consolidated Financial Statements.

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

	September 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$13,007	$7,604
Customer and other receivables	362,185	297,740
Accrued unbilled revenues	162,269	100,533
Allowance for doubtful accounts	(3,721)	(3,094)
Materials and supplies (at average cost)	234,987	218,889
Fossil fuel (at average cost)	43,536	37,097
Deferred income taxes	57,857	122,232
Income tax receivable (Note 5)	—	3,098
Assets from risk management activities (Note 7)	13,654	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	139,766	129,808
Other current assets	38,439	38,817
Total current assets	1,061,979	973,435
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 7)	15,308	17,620
Nuclear decommissioning trust (Note 12)	712,011	713,866
Other assets	52,486	54,047
Total investments and other assets	779,805	785,533
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	15,997,447	15,543,063
Accumulated depreciation and amortization	(5,537,860)	(5,397,751)
Net	10,459,587	10,145,312
Construction work in progress	752,296	682,807
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	118,352	121,255
Intangible assets, net of accumulated amortization	134,937	119,755
Nuclear fuel, net of accumulated amortization	137,519	125,201
Total property, plant and equipment	11,602,691	11,194,330
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,102,327	1,054,087
Assets for other postretirement benefits (Note 4)	172,983	152,290
Other	155,233	153,857
Total deferred debits	1,430,543	1,360,234
TOTAL ASSETS	$14,875,018	$14,313,532

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

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

	September 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$233,970	$295,211
Accrued taxes (Note 5)	250,679	140,613
Accrued interest	40,045	52,603
Common dividends payable	—	65,790
Short-term borrowings (Note 2)	57,000	147,400
Current maturities of long-term debt (Note 2)	411,433	383,570
Customer deposits	72,455	72,307
Liabilities from risk management activities (Note 7)	74,637	59,676
Deferred fuel and purchased power regulatory liability (Note 3)	12,222	—
Liabilities for asset retirements (Note 15)	26,875	32,462
Other regulatory liabilities (Note 3)	135,970	130,549
Other current liabilities	208,076	178,962
Total current liabilities	1,523,362	1,559,143
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 2)	3,257,347	3,031,215
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,673,394	2,582,636
Regulatory liabilities (Note 3)	995,757	1,051,196
Liabilities for asset retirements (Note 15)	421,949	358,288
Liabilities for pension benefits (Note 4)	383,801	453,736
Liabilities from risk management activities (Note 7)	96,360	50,602
Customer advances	121,905	123,052
Coal mine reclamation	201,040	198,292
Deferred investment tax credit	188,149	178,607
Unrecognized tax benefits (Note 5)	36,634	19,377
Other	184,001	188,286
Total deferred credits and other	5,302,990	5,204,072
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 110,900,630 and 110,649,762 issued at respective dates	2,529,019	2,512,970
Treasury stock at cost; 53,559 and 78,400 shares at respective dates	(1,765)	(3,401)
Total common stock	2,527,254	2,509,569
Retained earnings	2,190,387	1,926,065
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(56,421)	(57,756)
Derivative instruments	(7,569)	(10,385)
Total accumulated other comprehensive loss	(63,990)	(68,141)
Total shareholders' equity	4,653,651	4,367,493
Noncontrolling interests (Note 6)	137,668	151,609
Total equity	4,791,319	4,519,102

TOTAL LIABILITIES AND EQUITY	$14,875,018	$14,313,532

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$410,212	$414,161
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	428,121	371,722
Deferred fuel and purchased power	(137)	(26,880)
Deferred fuel and purchased power amortization	19,284	31,724
Allowance for equity funds used during construction	(26,214)	(21,979)
Deferred income taxes	168,071	136,777
Deferred investment tax credit	9,542	25,206
Change in derivative instruments fair value	(261)	300
Changes in current assets and liabilities:		
Customer and other receivables	(107,263)	(149,053)
Accrued unbilled revenues	(61,736)	(59,240)
Materials, supplies and fossil fuel	(22,537)	(3,346)
Income tax receivable	3,098	135,517
Other current assets	1,994	(4,428)
Accounts payable	(53,247)	(7,171)
Accrued taxes	110,066	118,934
Other current liabilities	16,952	48,407
Change in margin and collateral accounts — assets	(1,291)	(475)
Change in margin and collateral accounts — liabilities	30,678	(20,875)
Change in unrecognized tax benefits	(9,276)	1,744
Change in other long-term assets	15,042	(50,005)
Change in other long-term liabilities	(109,725)	(54,122)
Net cash flow provided by operating activities	821,373	886,918
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(778,700)	(618,658)
Contributions in aid of construction	33,982	8,537
Allowance for borrowed funds used during construction	(12,056)	(11,039)
Proceeds from nuclear decommissioning trust sales	330,304	269,276
Investment in nuclear decommissioning trust	(343,488)	(282,212)
Other	(2,830)	339
Net cash flow used for investing activities	(772,788)	(633,757)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	600,000	574,126
Repayment of long-term debt	(344,847)	(503,583)
Short-term borrowings and payments — net	(90,400)	(133,975)
Dividends paid on common stock	(192,466)	(187,778)
Common stock equity issuance	12,543	14,860
Distributions to noncontrolling interest	(28,012)	(15,869)
Other	—	3
Net cash flow used for financing activities	(43,182)	(252,216)

NET INCREASE IN CASH AND CASH EQUIVALENTS	5,403	945
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	7,604	9,526
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$13,007	$10,471

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(unaudited)
(dollars in thousands)

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount	Shares	Amount				
Balance, January 1, 2014	110,280,703	$2,491,558	(98,944)	$(4,308)	$1,785,273	$ (78,053)	$ 145,990	$4,340,460
Net income		—		—	392,185	—	21,976	414,161
Other comprehensive income		—		—	—	15,651	—	15,651
Dividends on common stock		—		—	(125,250)	—	—	(125,250)
Issuance of common stock	188,253	10,659		—	—	—	—	10,659
Purchase of treasury stock (a)		—	(83,639)	(4,598)	—	—	—	(4,598)
Reissuance of treasury stock for stock-based compensation and other		—	160,290	8,800	(1)	—	—	8,799
Net capital activities by noncontrolling interests		—		—	—	—	(15,869)	(15,869)
Balance, September 30, 2014	110,468,956	$2,502,217	(22,293)	$(106)	$2,052,207	$ (62,402)	$ 152,097	$4,644,013
Balance, January 1, 2015	110,649,762	$2,512,970	(78,400)	$(3,401)	$1,926,065	$ (68,141)	$ 151,609	$4,519,102
Net income		—		—	396,140	—	14,072	410,212
Other comprehensive income		—		—	—	4,151	—	4,151
Dividends on common stock		—		—	(131,818)	—	—	(131,818)
Issuance of common stock	250,868	16,049		—	—	—	—	16,049
Purchase of treasury stock (a)		—	(93,280)	(6,096)	—	—	—	(6,096)
Reissuance of treasury stock for		—	118,121	7,732	—	—	—	7,732

stock-based compensation and other								
Net capital activities by noncontrolling interests	—		—	—	—		(28,013)	(28,013)
Balance, September 30, 2015	110,900,630	$2,529,019	(53,559)	$(1,765)	$2,190,387	$ (63,990)	$ 137,668	$4,791,319

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

See Notes to Pinnacle West's Condensed Consolidated Financial Statements.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Consolidation and Nature of Operations

The unaudited condensed consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, Bright Canyon Energy Corporation ("BCE") and El Dorado Investment Company ("El Dorado"). Intercompany accounts and transactions between the consolidated companies have been eliminated. The unaudited condensed consolidated financial statements for APS include the accounts of APS and the Palo Verde Nuclear Generating Station ("Palo Verde") sale leaseback variable interest entities ("VIEs") (see Note 6 for further discussion). 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.

Weather conditions cause significant seasonal fluctuations in our revenues; therefore, results for interim periods do not necessarily represent results expected for the year.

Our condensed consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments except as otherwise disclosed in these notes) that we believe are necessary for the fair presentation of our financial position, results of operations, and cash flows for the periods presented. Certain information and footnote disclosures normally included in financial statements prepared in conformity with GAAP have been condensed or omitted pursuant to such regulations, although we believe that the disclosures provided are adequate to make the interim information presented not misleading. The accompanying condensed consolidated financial statements and these notes should be read in conjunction with the audited consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2014.

Supplemental Cash Flow Information

The following table summarizes supplemental Pinnacle West cash flow information (dollars in thousands):

	Nine Months Ended September 30,	
	2015	2014
Cash paid (received) during the period for:		
Income taxes, net of refunds	$2,692	$(131,154)
Interest, net of amounts capitalized	143,116	145,285
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$36,718	$24,135

2. Long-Term Debt and Liquidity Matters

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

Pinnacle West

Pinnacle West's $200 million revolving credit facility matures in May 2019. At September 30, 2015, the facility was available to refinance indebtedness of the Company and for other general corporate purposes, including credit support for its $200 million commercial paper program. Pinnacle West has the option to increase the size of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At September 30, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

APS

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

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

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness.

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

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

On October 27, 2015, notice was given that all Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A, approximately $38 million in principal amount, have been called for optional redemption on November 17, 2015. These bonds are classified as current maturities of long-term debt on our Condensed Consolidated Balance Sheets at September 30, 2015.

At September 30, 2015, APS had two credit facilities totaling $1 billion, including a $500 million credit facility that matures in September 2020 and a $500 million facility that matures in May 2019. APS may increase the size of each facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use these facilities to refinance indebtedness and for other general corporate purposes. Interest rates are based on APS's senior unsecured debt credit ratings.

The facilities described above are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At September 30, 2015, APS had $57 million of commercial paper outstanding and no outstanding borrowings or letters of credit under these credit facilities.

See "Financial Assurances" in Note 8 for a discussion of APS's separate outstanding letters of credit.

Debt Fair Value

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

	As of September 30, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$125	$125	$125	$125
APS	3,544	3,869	3,290	3,714
Total	$3,669	$3,994	$3,415	$3,839

Debt Provisions

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At September 30, 2015, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.8 billion, and total capitalization was approximately $8.5 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS’s total capitalization remains the same.

3. Regulatory Matters

Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. APS requested that the increase become effective July 1, 2012. The request would have increased the average retail customer bill by approximately 6.6%. On January 6, 2012, APS and other parties to the general retail rate case entered into 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.

Settlement Agreement

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

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

- An authorized return on common equity of 10.0%;

13

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

- A capital structure comprised of 46.1% debt and 53.9% common equity;
- A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;
- Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:
- Deferral of increases in property taxes of 25% in 2012, 50% in 2013 and 75% for 2014 and subsequent years if Arizona property tax rates increase; and
- Deferral of 100% in all years if Arizona property tax rates decrease;
- A procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of the Four Corners Power Plant ("Four Corners") (APS made its filing under this provision on December 30, 2013, see "Four Corners" below);
- Implementation of a Lost Fixed Cost Recovery ("LFCR") rate mechanism to support energy efficiency and distributed renewable generation;
- Modifications to the Environmental Improvement Surcharge ("EIS") to allow for the recovery of carrying costs for capital expenditures associated with government-mandated environmental controls, subject to an existing cents per kWh cap on cost recovery that could produce up to approximately $5 million in revenues annually;
- Modifications to the Power Supply Adjustor ("PSA"), including the elimination of the 90/10 sharing provision;
- A limitation on the use of the RES surcharge and the Demand Side Management Adjustor Charge ("DSMAC") to recoup capital expenditures not required under the terms of APS's 2009 retail rate case settlement agreement (the "2009 Settlement Agreement");
- Allowing a negative credit that existed in the PSA rate to continue until February 2013, rather than being reset on the anticipated July 1, 2012 rate effective date;
- Modification of the transmission cost adjustor ("TCA") to streamline the process for future transmission-related rate changes; and
- Implementation of various changes to rate schedules, including the adoption of an experimental "buy-through" rate that could allow certain large commercial and industrial customers to select alternative sources of generation to be supplied by APS.

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

Cost Recovery Mechanisms

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

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

On July 12, 2013, APS filed its annual RES implementation plan, covering the 2014-2018 timeframe and requesting a 2014 RES budget of approximately $143 million. In a final order dated January 7, 2014, the ACC approved the requested budget. Also in 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

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

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

On July 1, 2015, APS filed its 2016 RES implementation plan and proposed a RES budget of approximately $148 million.

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

15

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

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

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. Consistent with the ACC's March 11, 2014 order, APS intends to continue its other approved DSM programs in 2015.

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

Electric Energy Efficiency

On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

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

PSA Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The following table shows the changes in the deferred fuel and purchased power regulatory asset (liability) for 2015 and 2014 (dollars in millions):

	Nine Months Ended September 30,	
	2015	2014
Beginning balance	$7	$21
Deferred fuel and purchased power costs — current period	—	27
Amounts charged to customers	(19)	(32)
Ending balance	$(12)	$16

The PSA rate for the PSA year beginning February 1, 2015 is $0.000887 per kWh, as compared to $0.001557 per kWh for the prior year. This new rate is comprised of a forward component of $0.001131 per kWh and a historical component of $(0.000244) per kWh. On October 15, 2015, APS notified the ACC that it

16

intends to initiate a PSA transition component of $(0.004936) per kWh for the months of November 2015, December 2015, and January 2016. The PSA transition component is a mid-year adjustment to the PSA rate that may be established when conditions change sufficiently to cause high balances to accrue in the PSA balancing account. Any uncollected (overcollected) deferrals during the PSA year, after accounting for the transition component, will be included in the calculation of the PSA rate for the PSA year beginning February 1, 2016.

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

The formula rate is updated each year effective June 1 on the basis of APS's actual cost of service, as disclosed in APS's FERC Form 1 report for the previous fiscal year. Items to be updated include actual capital expenditures made as compared with previous projections, transmission revenue credits and other items. The resolution of proposed adjustments can result in significant volatility in the revenues to be collected. APS reviews the proposed formula rate filing amounts with the ACC staff. Any items or adjustments which are not agreed to by APS and the ACC staff can remain in dispute until settled or litigated at FERC. Settlement or litigated resolution of disputed issues could require an extended period of time and could have a significant effect on the Retail Transmission Charges because any adjustment, though applied prospectively, may be calculated to account for previously over- or under-collected amounts.

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

Effective June 1, 2015, APS's annual wholesale transmission rates for all users of its transmission system decreased by approximately $17.6 million for the twelve-month period beginning June 1, 2015 in accordance with the FERC-approved formula. An adjustment to APS's retail rates to recover FERC-approved transmission charges went into effect automatically on June 1, 2015.

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

Lost Fixed Cost Recovery Mechanism. The LFCR mechanism permits APS to recover on an after-the-fact basis a portion of its fixed costs that would otherwise have been collected by APS in the kWh sales lost due to APS energy efficiency programs and to distributed generation such as rooftop solar arrays. The fixed costs recoverable by the LFCR mechanism were established in the 2012 Settlement Agreement and amount to approximately 3.1 cents per residential kWh lost and 2.3 cents per non-residential kWh lost. The LFCR adjustment has a year-over-year cap of 1% of retail revenues. Any amounts left unrecovered in a particular year because of this cap can be carried over for recovery in a future year. The kWh's lost from energy efficiency are based on a third-party evaluation of APS's energy efficiency programs. Distributed generation sales losses are determined from the metered output from the distributed generation units or if metering is unavailable, through accepted estimating techniques.

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

Net Metering

On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electricity grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electrical grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift. In its December 2013 order, the ACC directed APS to provide quarterly reports on the pace of rooftop solar adoption to assist the ACC in considering further increases.

On April 2, 2015, APS filed an application with the ACC seeking to increase the fixed grid access charge to $3.00 per kilowatt, or approximately $21 per month for a typical new residential solar customer, effective August 1. In August 2015, the ACC ordered that a hearing be held to evaluate the merits of APS's April proposal. APS subsequently requested that the ACC redirect its focus to APS's cost to serve customers with rooftop solar and offered to withdraw its request to reset the grid access charge if such a cost of service proceeding could be expeditiously conducted.

On October 20, 2015, the ACC voted to rescind their earlier decision to hold a hearing regarding APS's request, dismissed APS's request to increase its grid access charge, and closed the docket in which the request was filed. The ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information which will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A procedural conference will be held to determine both a schedule for the hearing and the scope of the issues to be discussed at hearing. APS cannot predict the outcome of this proceeding.

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

In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC has sought review by the Arizona Supreme Court of this decision. If the

Supreme Court declines to review the case, or the decision is upheld by the

18

Supreme Court without modification, certain APS rate adjusters may be negatively impacted and may no longer operate as they do currently. This could in turn have a significant impact on APS' ability to recover certain costs in between rate cases. APS intends to support the ACC's petition to the Supreme Court for review of the Court of Appeals' decision, but cannot predict the outcome of this matter.

Four Corners

On December 30, 2013, APS purchased Southern California Edison Company's ("SCE's") 48% ownership interest in each of Units 4 and 5 of Four Corners. The 2012 Settlement Agreement includes a procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of the additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. APS made its filing under this provision on December 30, 2013. On December 23, 2014, the ACC approved rate adjustments resulting in a revenue increase of $57.1 million on an annual basis. This includes the deferral for future recovery of all non-fuel operating costs for the acquired SCE interest in Four Corners, net of the non-fuel operating costs savings resulting from the closure of Units 1-3 from the date of closing of the purchase through its inclusion in rates. The 2012 Settlement Agreement also provides for deferral for future recovery of all unrecovered costs incurred in connection with the closure of Units 1-3. The deferral balance related to the acquisition of SCE's interest in Units 4 and 5 and the closure of Units 1-3 was $72 million as of September 30, 2015 and is being amortized in rates over 10 years. On February 23, 2015, the Arizona School Boards Association and the Association of Business Officials filed a notice of appeal in Division 1 of the Arizona Court of Appeals of the ACC decision approving the rate adjustments. APS has intervened and is actively participating in the proceeding. We cannot predict when or how this appeal will be resolved; however, the eventual outcome of the SIB matter discussed above could have an effect on the outcome of this proceeding.

As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third-parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. APS and SCE continue to evaluate potential paths forward. APS believes that the original denial by FERC of rate recovery under the Transmission Termination Agreement constitutes the failure of a condition that relieves APS of its obligations under that agreement. If APS and SCE are unable to determine a resolution through negotiation, the Transmission Termination Agreement requires that disputes be resolved through arbitration. APS is unable to predict the outcome of this matter if it proceeds to arbitration. If the matter proceeds to arbitration and APS is not successful, APS may be required to record a charge to its results of operations.

Cholla

After considering the costs to comply with environmental regulations, on September 11, 2014, APS announced that it will close Unit 2 of the Cholla Power Plant ("Cholla") 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 the United States Environmental Protection Agency ("EPA") approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. Previously, APS estimated Cholla Unit 2's end of life to be 2033. APS is currently recovering 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. On April 14, 2015, the ACC approved APS's proposed retirement of Cholla Unit 2 in accordance with the ACC's Integrated Resource Planning rules. The ACC expressly stated that this approval does not imply any specific treatment or recommendation for rate making purposes.

APS closed Cholla Unit 2 on October 1, 2015. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($124 million as of September 30, 2015), in addition to a return on its investment. In accordance with GAAP, in the third quarter of 2014, Unit 2's remaining net book value was reclassified from property, plant and equipment to a regulatory asset. If the ACC does not allow full recovery of the remaining net book value of Cholla Unit 2, all or a portion of the regulatory asset will be written off and APS's net income, cash flows, and financial position will be negatively impacted.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Assets and Liabilities
The detail of regulatory assets is as follows (dollars in millions):

	Remaining Amortization Period	September 30, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Pension benefits	(a)	$—	$ 498	$—	$ 485
Income taxes — allowance for funds used during construction ("AFUDC") equity	2044	5	132	5	118
Deferred fuel and purchased power — mark-to-market (Note 7)	2018	63	73	51	46
Transmission vegetation management	2016	7	—	9	5
Coal reclamation	2026	—	6	—	7
Palo Verde VIEs (Note 6)	2046	—	22	—	35
Deferred compensation	2036	—	36	—	34
Deferred fuel and purchased power (b) (c)	2015	—	—	7	—
Tax expense of Medicare subsidy	2024	2	12	2	14
Loss on reacquired debt	2034	1	15	1	16
Income taxes — investment tax credit basis adjustment	2044	2	49	2	46
Four Corners cost deferral	2024	7	65	7	70
Lost fixed cost recovery (b)	2016	43	—	38	—
Retired power plant costs	2033	10	130	10	136
Deferred property taxes	(d)	—	46	—	30
Other	Various	—	18	6	12
Total regulatory assets (e)		$ 140	$ 1,102	$ 138	$ 1,054

(a) This asset represents the future recovery of pension and other postretirement benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to Other Comprehensive Income ("OCI") and result in lower future revenues. See Note 4 for further discussion.
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) Per the provision of the 2012 Settlement Agreement.
(e) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters."

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Remaining Amortization Period	September 30, 2015		December 31, 2014	
		Current	Non-Current	Current	Non-Current
Removal costs	(a)	$41	$ 244	$31	$ 273
Asset retirement obligations	2045	—	259	—	296
Renewable energy standard (b)	2017	28	21	25	23
Income taxes — change in rates	2043	1	70	—	72
Spent nuclear fuel	2047	3	68	5	66
Deferred gains on utility property	2019	2	7	2	8
Income taxes — deferred investment tax credit	2043	3	98	4	93
Deferred fuel and purchased power (b) (c)	2016	12	—	—	—
Demand side management (b)	2017	17	20	31	—
Other postretirement benefits	(d)	33	181	32	199
Other	Various	8	28	1	21
Total regulatory liabilities		$148	$ 996	$131	$ 1,051

(a) In accordance with regulatory accounting guidance, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal.
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Subject to a carrying charge.
(d) See Note 4.

4. Retirement Plans and Other Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan, a non-qualified supplemental excess benefit retirement plan, and an other postretirement benefit plan for the employees of Pinnacle West and our subsidiaries. Pinnacle West uses a December 31 measurement date for its pension and other postretirement benefit plans. The market-related value of our plan assets is their fair value at the measurement dates. On September 30, 2014, Pinnacle West announced plan design changes to the other postretirement benefit plan. Because of these plan changes in 2014, the Company is currently in the process of seeking Internal Revenue Service ("IRS") and regulatory approval to move approximately $100 million of the other postretirement benefit trust assets into a new account to pay for active union employee medical costs.

Certain pension and other postretirement benefit costs in excess of amounts recovered in electric retail rates were deferred in 2011 and 2012 as a regulatory asset for future recovery, pursuant to APS’s 2009 retail rate case settlement. Pursuant to this order, we began amortizing the regulatory asset over three years beginning in July 2012. We have completed amortizing these costs as of June 30, 2015. We amortized approximately $2 million for the three months ended September 30, 2014. We have amortized $4 million and $6 million for the nine months ended September 30, 2015 and 2014, respectively. The following table provides details of the plans’ net periodic benefit costs and the portion of these costs charged to expense (including administrative costs and excluding amounts capitalized as overhead construction, billed to electric plant participants or charged or amortized to the regulatory asset) (dollars in millions):

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits				Other Benefits			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
Service cost — benefits earned during the period	$15	$13	$45	$40	$4	$5	$13	$14
Interest cost on benefit obligation	31	32	93	97	7	12	21	35
Expected return on plan assets	(45)	(39)	(134)	(119)	(9)	(13)	(28)	(38)
Amortization of:								
Prior service cost	—	—	—	—	(9)	—	(29)	—
Net actuarial loss	8	3	23	8	1	—	4	—
Net periodic benefit cost	$9	$9	$27	$26	$(6)	$4	$(19)	$11
Portion of cost charged to expense	$4	$5	$16	$16	$(3)	$3	$(7)	$8

Contributions

We have made voluntary contributions of $100 million to our pension plan year-to-date in 2015. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions totaling up to $200 million for the next two years (up to $100 million each year in 2016 and 2017). We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans.

5. Income Taxes

On September 13, 2013, the U.S. Treasury Department released final income tax regulations on the deduction and capitalization of expenditures related to tangible property. These final regulations apply to tax years beginning on or after January 1, 2014. Several of the provisions within the regulations required a tax accounting method change which was filed with the IRS on September 11, 2015. The impact of these final regulations was materially consistent with the estimated tax-effected cumulative effect adjustment of approximately $82 million that was accounted for as a reduction to net deferred income taxes in the Condensed Consolidated Balance Sheets as of December 31, 2014.

Net income associated with the Palo Verde sale leaseback variable interest entities is not subject to tax (see Note 6). As a result, there is no income tax expense associated with the VIEs recorded on the Condensed Consolidated Statements of Income.

As of September 30, 2015, the tax year ended December 31, 2012 and all subsequent tax years remain subject to examination by the IRS. With few exceptions, we are no longer subject to state income tax examinations by tax authorities for years before 2009.

6. Palo Verde Sale Leaseback Variable Interest Entities

In 1986, APS entered into agreements with three separate VIE lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities. These lease agreements include fixed rate renewal periods. 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. APS will be required to make payments relating to these leases of approximately $49 million in 2015, $23 million annually for the period 2016 through 2023, and $16 million annually for the period 2024 through 2033. 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 2 years, or return the assets to the lessors.

The fixed rate renewal periods give APS the ability to utilize the assets for a significant portion of the assets' economic life, and therefore provide APS with the power to direct activities of the VIEs that most significantly impact the VIEs' economic performance. Predominately due to the fixed rate renewal periods, APS has been deemed the primary beneficiary of these VIEs and therefore consolidates the VIEs.

As a result of consolidation, we eliminate lease accounting and instead recognize depreciation and interest expense, resulting in an increase in net income for the three and nine months ended September 30, 2015 of $5 million and $14 million, respectively, and for the three and nine months ended September 30, 2014 of $4 million and $22 million, respectively, entirely attributable to the noncontrolling interests. The income attributable to the noncontrolling interests decreased for the nine months ended September 30, 2015 compared with the prior-year period because of lower rent income resulting from the July 7, 2014 lease extensions.

In accordance with the regulatory treatment, higher depreciation expense and a regulatory liability were recorded in consolidation to offset the decrease in the noncontrolling interests' share of net income that resulted from the lease extensions. Accordingly, income attributable to Pinnacle West shareholders was not impacted by the consolidation or the lease extensions. Consolidation of these VIEs also results in changes to our Condensed Consolidated Statements of Cash Flows, but does not impact net cash flows.

Our Condensed Consolidated Balance Sheets at September 30, 2015 and December 31, 2014 include the following amounts relating to the VIEs (in millions):

	September 30, 2015	December 31, 2014
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$118	$121
Current maturities of long-term debt	1	13
Equity — Noncontrolling interests	138	152

Assets of the VIEs are restricted and may only be used to settle the VIEs' debt obligations and for payment to the noncontrolling interest holders. Other than the VIEs' assets reported on our consolidated financial statements, the creditors of the VIEs have no other recourse to the assets of APS or Pinnacle West, except in certain circumstances such as a default by APS under the lease.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the United States Nuclear Regulatory

Commission ("NRC") issuing specified violation orders with respect to Palo Verde or the

24

occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants, assume the VIEs' debt, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of September 30, 2015, APS would have been required to pay the noncontrolling equity participants approximately $114 million and assume $1 million of debt. Since APS consolidates these VIEs, the debt APS would be required to assume is already reflected in our Condensed Consolidated Balance Sheets. If such an event were to occur during the lease extension period, APS would be required to pay the noncontrolling equity participants approximately $288 million beginning in 2016, and up to $456 million over the lease extension term.

For regulatory ratemaking purposes, the agreements continue to be treated as operating leases and, as a result, we have recorded a regulatory asset relating to the arrangements.

7. Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial derivative 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. Derivative instruments that meet certain hedge accounting criteria may be designated as cash flow hedges and are used to limit our exposure to cash flow variability on forecasted transactions. The changes in market value of such instruments have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. While we believe the economic hedges mitigate exposure to fluctuations in commodity prices, these instruments have not been designated as accounting hedges. 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 costs in our Condensed Consolidated Statements of Income, but does not impact our financial condition, net income or cash flows.

On June 1, 2012, we elected to discontinue cash flow hedge accounting treatment for the significant majority of our contracts that had previously been designated as cash flow hedges. This discontinuation is due to changes in PSA recovery (see Note 3), which now allows for 100% deferral of the unrealized gains and losses relating to these contracts. For those contracts that were de-designated, all changes in fair value after May 31, 2012 are no longer recorded through OCI, but are deferred through the PSA. The amounts previously recorded in accumulated OCI relating to these instruments will remain in accumulated OCI, and will transfer to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if we determine it is probable that the forecasted transaction will not occur. When amounts have been reclassified from accumulated OCI to earnings, they will be subject to deferral in accordance with the PSA. Cash flow hedge accounting treatment will continue for a limited number of contracts that are not subject to PSA recovery.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheet as an asset or liability and are measured at fair value. See Note 11 for a discussion of fair value measurements. Derivative instruments may qualify for the normal purchases and normal sales scope exception if they require physical delivery and the quantities represent those transacted in the normal course of business. Derivative instruments qualifying for the normal purchases and sales scope exception are accounted for under the accrual method of accounting and excluded from our derivative instrument discussion and disclosures below.

25

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Hedge effectiveness is the degree to which the derivative instrument contract and the hedged item are correlated and is measured based on the relative changes in fair value of the derivative instrument contract and the hedged item over time. We assess hedge effectiveness both at inception and on a continuing basis. These assessments exclude the time value of certain options. For accounting hedges that are deemed an effective hedge, the effective portion of the gain or loss on the derivative instrument is reported as a component of OCI and reclassified into earnings in the same period during which the hedged transaction affects earnings. We recognize in current earnings, subject to the PSA, the gains and losses representing hedge ineffectiveness, and the gains and losses on any hedge components which are excluded from our effectiveness assessment. As cash flow hedge accounting has been discontinued for the significant majority of our contracts, after May 31, 2012, effectiveness testing is no longer being performed for these contracts.

For its regulated operations, APS defers for future rate treatment 100% of the unrealized gains and losses on derivatives pursuant to the PSA mechanism that would otherwise be recognized in income. Realized gains and losses on derivatives are deferred in accordance with the PSA to the extent the amounts are above or below the Base Fuel Rate (see Note 3). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of September 30, 2015, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Quantity	
Power	2,926	GWh
Gas	178	Billion cubic feet

Gains and Losses from Derivative Instruments

The following table provides information about gains and losses from derivative instruments in designated cash flow accounting hedging relationships during the three and nine months ended September 30, 2015 and 2014 (dollars in thousands):

	Financial Statement Location	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts		2015	2014	2015	2014
Gain (loss) recognized in OCI on derivative instruments (effective portion)	OCI — derivative instruments	$(247)	$(149)	$(534)	$94
Loss reclassified from accumulated OCI into income (effective portion realized) (a)	Fuel and purchased power (b)	(1,459)	(9,772)	(5,232)	(17,426)

(a) During the three and nine months ended September 30, 2015 and 2014, we had no amounts reclassified from accumulated OCI to earnings related to discontinued cash flow hedges.
(b) Amounts are before the effect of PSA deferrals.

During the next twelve months, we estimate that a net loss of $4 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

26

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the three and nine months ended September 30, 2015 and 2014 (dollars in thousands):

		Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts	Financial Statement Location	2015	2014	2015	2014
Net gain recognized in income	Operating revenues (a)	$560	$273	$445	$335
Net loss recognized in income	Fuel and purchased power (a)	(50,909)	(23,915)	(85,099)	(1,003)
Total		$(50,349)	$(23,642)	$(84,654)	$(668)

(a) Amounts are before the effect of PSA deferrals.

Derivative Instruments in the Condensed Consolidated Balance Sheets

Our derivative transactions are typically executed under standardized or customized agreements, which include collateral requirements and, in the event of a default, would allow for the netting of positive and negative exposures associated with a single counterparty. Agreements that allow for the offsetting of positive and negative exposures associated with a single counterparty are considered master netting arrangements. Transactions with counterparties that have master netting arrangements are offset and reported net on the Condensed Consolidated Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are reported gross on the Condensed Consolidated Balance Sheets.

We do not offset a counterparty's current derivative contracts with the counterparty's non-current derivative contracts, although our master netting arrangements would allow current and non-current positions to be offset in the event of a default. Additionally, in the event of a default, our master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, trade receivables and trade payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting tables presented below.

The significant majority of our derivative instruments are not currently designated as hedging instruments. The Condensed Consolidated Balance Sheets as of September 30, 2015 and December 31, 2014, each include gross liabilities of $4 million of derivative instruments designated as hedging instruments.

The following tables provide information about the fair value of our risk management activities reported on a gross basis, and the impacts of offsetting as of September 30, 2015 and December 31, 2014. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of our Condensed Consolidated Balance Sheets.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As of September 30, 2015: (Dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$32,129	$(18,885)	$13,244	$410	$13,654
Investments and other assets	18,418	(4,340)	14,078	1,230	15,308
Total assets	50,547	(23,225)	27,322	1,640	28,962
Current liabilities	(99,301)	32,785	(66,516)	(8,121)	(74,637)
Deferred credits and other	(100,700)	4,340	(96,360)	—	(96,360)
Total liabilities	(200,001)	37,125	(162,876)	(8,121)	(170,997)
Total	$(149,454)	$13,900	$(135,554)	$(6,481)	$(142,035)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $13,900.
(c) Represents cash collateral, cash margin and option premiums that are not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $8,121, cash margin provided to counterparties of $410 and option premiums of $1,230.

As of December 31, 2014: (Dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$28,562	$(15,127)	$13,435	$350	$13,785
Investments and other assets	24,810	(7,190)	17,620	—	17,620
Total assets	53,372	(22,317)	31,055	350	31,405
Current liabilities	(86,062)	33,829	(52,233)	(7,443)	(59,676)
Deferred credits and other	(82,990)	32,388	(50,602)	—	(50,602)
Total liabilities	(169,052)	66,217	(102,835)	(7,443)	(110,278)
Total	$(115,680)	$43,900	$(71,780)	$(7,093)	$(78,873)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) Includes cash collateral provided to counterparties of $43,900.
(c) Represents cash collateral and margin that is not subject to offsetting. Amounts relate to non-derivative instruments, derivatives qualifying for scope exceptions, or collateral and margin posted in excess of the recognized derivative instrument. Includes cash collateral received from counterparties of $7,443, and cash margin provided to counterparties of $350.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management contracts with many counterparties, including one counterparty for which our exposure represents approximately 91% of Pinnacle West's $29 million of risk management assets as of September 30, 2015. This exposure relates to a long-term traditional wholesale contract with a counterparty that has a high credit quality. Our risk management process assesses and monitors the financial exposure of all counterparties.

28

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Despite the fact that the great majority of trading counterparties' debt is rated as investment grade by the credit rating agencies, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of financial institutions, major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. To manage credit risk, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties.

Certain of our derivative instrument contracts contain credit-risk-related contingent features including, among other things, investment grade credit rating provisions, credit-related cross-default provisions, and adequate assurance provisions. Adequate assurance provisions allow a counterparty with reasonable grounds for uncertainty to demand additional collateral based on subjective events and/or conditions. For those derivative instruments in a net liability position, with investment grade credit contingencies, the counterparties could demand additional collateral if our debt credit rating were to fall below investment grade (below BBB- for Standard & Poor's or Fitch or Baa3 for Moody's).

The following table provides information about our derivative instruments that have credit-risk-related contingent features at September 30, 2015 (dollars in millions):

	September 30, 2015
Aggregate fair value of derivative instruments in a net liability position	$200
Cash collateral posted	14
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	112

(a) This amount is after counterparty netting and includes those contracts which qualify for scope exceptions, which are excluded from the derivative details above.

We also have energy-related non-derivative instrument contracts with investment grade credit-related contingent features, which could also require us to post additional collateral of approximately $161 million if our debt credit ratings were to fall below investment grade.

8. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit seeks to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified

29

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 income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through 2016.

APS’s first claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2011 through June 30, 2014, and was for $42.0 million (APS’s share of this amount was $12.2 million), was received on June 1, 2015. APS's $12.2 million share was recorded as an adjustment to a regulatory liability and had no impact on income. APS’s second claim made pursuant to the terms of the August 18, 2014 settlement agreement, which was for the period July 1, 2014 through June 30, 2015, and is estimated to be $12.0 million (APS's share of this amount would be $3.5 million), will be submitted to the DOE in the fourth quarter of 2015.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to $13.4 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $375 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of $12.98 billion of liability coverage is provided through a mandatory industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum retrospective premium assessment per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to an annual limit of $19 million per incident, to be periodically adjusted for inflation. Based on APS’s ownership interest in the three Palo Verde units, APS’s maximum potential retrospective premium assessment per incident for all three units is approximately $111 million, with a maximum annual retrospective premium assessment of approximately $16.5 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of replacement generation or purchased power and business interruption resulting from a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and replacement power coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium assessments under all NEIL policies if NEIL’s losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $23.1 million for each retrospective premium assessment declared by NEIL’s Board of Directors due to losses. In addition, NEIL policies contain rating triggers that would result in APS providing approximately $61.6 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.

Contractual Obligations

During 2015 our purchase obligations increased by about $170 million relating to gas generation projects at our Ocotillo plant and $359 million relating to selective catalytic reduction control technologies at our Four Corners Plant. The expected payments to be made relating to these additional purchase obligations are $42 million in 2015, $269 million in 2016, $176 million in 2017, and $42 million in 2018.

Other than the items described above, there have been no material changes, as of September 30, 2015, outside the normal course of business in contractual obligations from the information provided in our 2014 Form 10-K. See Note 2 for discussion regarding changes in our long-term debt obligations.

Superfund-Related Matters

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

On August 6, 2013, the Roosevelt Irrigation District ("RID") filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RID's groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APS's current and former ownership of facilities in and around OU3. As part of a state governmental investigation into groundwater contamination in this area, on January 25, 2015, the Arizona Department of Environmental Quality ("ADEQ") sent a letter to APS seeking information concerning the degree to which, if any, APS's current and former ownership of these facilities may have contributed to groundwater contamination in this area. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Southwest Power Outage

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

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

Clean Air Act Citizen Lawsuit

On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners participants alleging violations of the New Source Review ("NSR") provisions of the Clean Air Act. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the Clean Air Act's New Source Performance Standards ("NSPS") program. Among other things, the environmental plaintiffs sought to have the court enjoin operations at Four Corners until APS applied for and obtained any required NSR permits and complied with the NSPS. The plaintiffs further requested the court to order the payment of civil penalties, including a beneficial mitigation project. The case was held in abeyance while APS negotiated a settlement with the United States Department of Justice ("DOJ") and environmental plaintiffs. In March 2015, the parties agreed in principle on final proposed language to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

The settlement requires installation of pollution control technology and implementation of other measures to reduce sulfur dioxide and nitrogen oxide emissions from the two units, although installation of much of this equipment was already planned in order to comply with EPA's Regional Haze Rule best available retrofit technology ("BART") requirements. The settlement also requires the Four Corners co-owners to pay a civil penalty of $1.5 million and spend $6.2 million for certain environmental mitigation projects to benefit the Navajo Nation. APS is responsible for 15 percent of these costs based on its ownership interest in the units at the time of the alleged violations, which does not result in a material impact on our financial position, results of operations or cash flows.

Environmental Matters

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

Regional Haze Rules. APS has received the final rulemaking imposing new requirements on Four Corners, Cholla and the Navajo Generating Station ("Navajo Plant"). EPA and ADEQ will require these plants to install pollution control equipment that constitutes BART to lessen the impacts of emissions on visibility surrounding the plants.

Four Corners. Based on EPA's final standards, APS estimates that its 63% share of the cost of these controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso

32

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. The cost of the controls related to the 7% interest is approximately $45 million.

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. In October 2014, a coalition of environmental groups, an Indian tribe and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this review process.

Cholla. APS believes that EPA's final rule as it applies to Cholla, which would require installation of selective catalytic reduction ("SCR") controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona's State Implementation Plan ("SIP") and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014. In September 2014, APS met with EPA to propose a compromise BART strategy wherein, pending certain regulatory approvals, APS would permanently close Cholla Unit 2 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 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 NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rule-making processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015. On October 16, 2015, ADEQ issued the Cholla permit, which incorporates APS's proposal, and submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. APS is unable to predict when or whether APS's proposal may ultimately be approved by the EPA.

Mercury and Air Toxic Standards ("MATS"). In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $11 million for Cholla (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. Salt River Project Agricultural Improvement and Power District ("SRP"), the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in Michigan vs. EPA reversed and remanded the MATS rule. This decision does not materially impact APS. Regardless of whether the MATS rule is ultimately vacated by the lower court, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

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

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

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

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

Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standard, greenhouse gas ("GHG") emissions (such as the EPA's "Clean Power Plan" rule), and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our coal plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement, but cannot predict whether it would obtain such recovery.

New Mexico Tax Matter

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

Financial Assurances

APS has entered into various agreements that require letters of credit for financial assurance purposes. At September 30, 2015, approximately $76 million of letters of credit were outstanding to support existing pollution control bonds of a similar amount. The letters of credit are available to fund the payment of principal and interest of such debt obligations. Two of these letters of credit expire in 2016 and one expires in 2017. APS has also entered into letters of credit to support certain equity participants in the Palo Verde sale leaseback transactions (see Note 6 for further details on the Palo Verde sale leaseback transactions). These letters of credit will expire on December 31, 2015, and totaled approximately $5 million at September 30, 2015. Additionally, APS has issued letters of credit to support collateral obligations under certain risk management arrangements, including a natural gas tolling contract entered into with a third party. At September 30, 2015, $35 million of such letters of credit were outstanding that will expire in 2016.

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

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at September 30, 2015.

9. Other Income and Other Expense

The following table provides detail of other income and other expense for the three and nine months ended September 30, 2015 and 2014 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Other income:				
Interest income	$127	$103	$422	$849
Miscellaneous	12	2,263	127	6,665
Total other income	$139	$2,366	$549	$7,514
Other expense:				
Non-operating costs	$(2,328)	$(1,985)	$(6,529)	$(6,976)
Investment losses — net	(563)	(118)	(1,708)	(364)
Miscellaneous	(2,647)	(2,090)	(4,196)	(2,045)
Total other expense	$(5,538)	$(4,193)	$(12,433)	$(9,385)

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

10. Earnings Per Share

The following table presents the calculation of Pinnacle West's basic and diluted earnings per share for the three and nine months ended September 30, 2015 and 2014 (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income attributable to common shareholders	$257,116	$243,961	$396,140	$392,185
Weighted average common shares outstanding — basic	111,036	110,686	110,984	110,579
Net effect of dilutive securities:				
Contingently issuable performance shares and restricted stock units	580	417	506	383
Weighted average common shares outstanding — diluted	111,616	111,103	111,490	110,962
Earnings per average common share attributable to common shareholders — basic	$2.32	$2.20	$3.57	$3.55
Earnings per average common share attributable to common shareholders — diluted	$2.30	$2.20	$3.55	$3.53

11. Fair Value Measurements

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

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

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

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

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

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

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust and plan assets held in our retirement and other benefit plans. See Note 7 in the 2014 Form 10-K for the fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

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

Risk Management Activities — Derivative Instruments

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

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

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

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

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

Investments Held in our Nuclear Decommissioning Trust

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

Cash equivalents reported within Level 2 represent investments held in a short-term investment commingled fund, valued using NAV, which invests in certificates of deposit, variable rate notes, time deposit accounts, U.S. Treasury and Agency obligations, U.S. Treasury repurchase agreements, and commercial paper. We may transact in this commingled fund on a daily basis at the NAV.

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

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee’s internal operating controls and valuation processes. See Note 12 for additional discussion about our nuclear decommissioning trust.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Fair Value Tables

The following table presents the fair value at September 30, 2015, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in millions):

	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 September 30, 2015
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$—	$22	$29	$(22)	(b)	$29
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	294	—	—		294
Cash and cash equivalent funds	—	11	—	—		11
Fixed income securities:						
U.S. Treasury	99	2	—	—		101
Corporate debt	—	114	—	—		114
Mortgage-backed securities	—	88	—	—		88
Municipal bonds	—	85	—	—		85
Other	—	19	—	—		19
Subtotal nuclear decommissioning trust	99	613	—	—		712
Total	$99	$635	$29	$(22)		$741
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$—	$(130)	$(70)	$29	(b)	$(171)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral (see Note 7).

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value at December 31, 2014, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in millions):

	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, 2014
Assets						
Risk management activities — derivative instruments:						
Commodity contracts	$—	$21	$33	$(23)	(b)	$31
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	310	—	—		310
Fixed income securities:						
U.S. Treasury	119	—	—	—		119
Cash and cash equivalent funds	—	11	—	(7)	(c)	4
Corporate debt	—	109	—	—		109
Mortgage-backed securities	—	89	—	—		89
Municipal bonds	—	69	—	—		69
Other	—	14	—	—		14
Subtotal nuclear decommissioning trust	119	602	—	(7)		714
Total	$119	$623	$33	$(30)		$745
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$—	$(95)	$(74)	$59	(b)	$(110)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.
(b) Represents counterparty netting, margin and collateral (see Note 7).
(c) Represents nuclear decommissioning trust net pending securities sales and purchases.

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

Our option contracts classified as Level 3 primarily relate to purchase heat rate options. The significant unobservable inputs at September 30, 2015 for these instruments include electricity prices, and volatilities. The significant unobservable inputs at December 31, 2014 for these instruments include electricity prices, gas prices and volatilities. If electricity prices and electricity price volatilities increase, we would expect the fair value of these options to increase, and if these valuation inputs decrease, we would expect the fair value of these options to decrease. If natural gas prices and natural gas price volatilities increase, we would expect the fair value of these options to decrease, and if these inputs decrease, we would expect the fair value of the options to increase. The commodity prices and volatilities do not always move in corresponding directions. The options' fair values are impacted by the net changes of these various inputs.

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 September 30, 2015 and December 31, 2014:

	September 30, 2015 Fair Value (millions)		Valuation Technique	Significant Unobservable Input	Range	Weighted-Average	
Commodity Contracts	Assets	Liabilities					
Electricity:							
Forward Contracts (a)	$27	$56	Discounted cash flows	Electricity forward price (per MWh)	$17.37 - $40.62	$ 28.25	
Option Contracts (b)	—	7	Option model	Electricity forward price (per MWh)	$28.36 - $46.50	$ 35.55	
				Electricity price volatilities	48% -61%	55	%
				Natural gas price volatilities	30% - 47%	34	%
Natural Gas:							
Forward Contracts (a)	2	7	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.32 - $3.17	$ 2.73	
Total	$29	$70					

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Commodity Contracts	December 31, 2014 Fair Value (millions) Assets	Liabilities	Valuation Technique	Significant Unobservable Input	Range	Weighted-Average
Electricity:						
Forward Contracts (a)	$30	$56	Discounted cash flows	Electricity forward price (per MWh)	$19.51 - $56.72	$ 35.27
Option Contracts (b)	—	15	Option model	Electricity forward price (per MWh)	$32.14 - $66.09	$ 45.83
				Natural gas forward price (per MMBtu)	$3.18 - $3.29	$ 3.25
				Electricity price volatilities	23% - 63%	41 %
				Natural gas price volatilities	23% - 41%	31 %
Natural Gas:						
Forward Contracts (a)	3	3	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.98 - $4.13	$ 3.45
Total	$33	$74				

(a) Includes swaps and physical and financial contracts.
(b) Electricity and natural gas price volatilities are estimated based on historical forward price movements due to lack of market quotes for implied volatilities.

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 three and nine months ended September 30, 2015 and 2014 (dollars in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Commodity Contracts	2015	2014	2015	2014
Net derivative balance at beginning of period	$(43)	$(41)	$(41)	$(49)
Total net gains (losses) realized/unrealized:				
Deferred as a regulatory asset or liability	(6)	(3)	(11)	4
Settlements	8	6	12	10
Transfers into Level 3 from Level 2	(1)	—	(5)	(2)
Transfers from Level 3 into Level 2	1	(1)	4	(2)
Net derivative balance at end of period	$(41)	$(39)	$(41)	$(39)
Net unrealized gains included in earnings related to instruments still held at end of period	$—	$—	$—	$—

Amounts included in earnings are recorded in either operating revenues or fuel and purchased power depending on the nature of the underlying contract.

42

Transfers 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 net accounts receivable, accounts payable and short-term borrowings approximate fair value. Our short-term borrowings are classified within Level 2 of the fair value hierarchy. For our long-term debt fair values, see Note 2.

12. Nuclear Decommissioning Trusts

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. Third-party investment managers are authorized to buy and sell securities per stated investment guidelines. The trust funds are invested in fixed income securities and equity securities. APS classifies investments in decommissioning trust funds as available for sale. As a result, we record the decommissioning trust funds at their fair value on our Condensed Consolidated Balance Sheets. See Note 11 for a discussion of how fair value is determined and the classification of the nuclear decommissioning trust investments within the fair value hierarchy. Because of the ability of APS to recover decommissioning costs in rates and in accordance with the regulatory treatment for decommissioning trust funds, we have deferred realized and unrealized gains and losses (including other-than-temporary impairments on investment securities) in other regulatory liabilities. The following table includes the unrealized gains and losses based on the original cost of the investment and summarizes the fair value of APS's nuclear decommissioning trust fund assets at September 30, 2015 and December 31, 2014 (dollars in millions):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
September 30, 2015			
Equity securities	$294	$138	$(1)
Fixed income securities	418	15	(3)
Total	$712	$153	$(4)

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2014			
Equity securities	$310	$159	$—
Fixed income securities	411	17	(1)
Net payables (a)	(7)	—	—
Total	$714	$176	$(1)

(a) Net payables relate to pending purchases and sales of securities.

The costs of securities sold are determined on the basis of specific identification. The following table sets forth approximate gains and losses and proceeds from the sale of securities by the nuclear decommissioning trust funds (dollars in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Realized gains	$2	$2	$4	$4
Realized losses	(2)	(2)	(4)	(5)
Proceeds from the sale of securities (a)	105	70	330	269

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at September 30, 2015 is as follows (dollars in millions):

	Fair Value
Less than one year	$15
1 year – 5 years	117
5 years – 10 years	117
Greater than 10 years	169
Total	$418

13. New Accounting Standards

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

In February 2015, new guidance was issued that amends the consolidation accounting guidance. The amendments modify many aspects of the guidance relating to the analysis and consolidation of variable interest entities. These changes include impacts on the following: limited partnerships, fees paid to decision makers, related parties, and the determination of whether an entity qualifies as a variable interest entity. The new guidance is effective for us on January 1, 2016, and may be adopted using either a full retrospective or modified retrospective approach. We are currently evaluating this amended guidance and the impacts it may have on our financial statements.

In April 2015, the Financial Accounting Standards Board issued new guidance that changes the balance sheet presentation of debt issuance costs. Currently, debt issuance costs are presented on the balance sheet as assets. The new guidance requires us to reflect debt issuance costs as a reduction to the related debt liabilities, consistent with the presentation of debt discounts. The new guidance is effective for us during the first quarter of 2016, and must be adopted retrospectively. We do not expect these presentation changes to be material to our balance sheet. The adoption of this new guidance will not impact our results of operations or cash flows.

14. Changes in Accumulated Other Comprehensive Loss

The following tables show the changes in accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three and nine months ended September 30, 2015 and 2014 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Balance at beginning of the period	$(65,600)	$(74,217)	$(68,141)	$(78,053)
Derivative Instruments				
OCI (loss) before reclassifications	(151)	(91)	(926)	(472)
Amounts reclassified from accumulated other comprehensive loss (a)	892	5,939	3,742	11,009
Net current period OCI (loss)	741	5,848	2,816	10,537
Pension and Other Postretirement Benefits				
OCI (loss) before reclassifications	—	5,231	(969)	3,159
Amounts reclassified from accumulated other comprehensive loss (b)	869	736	2,304	1,955
Net current period OCI (loss)	869	5,967	1,335	5,114
Ending balance, September 30	$(63,990)	$(62,402)	$(63,990)	$(62,402)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 7.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 4.

15. Asset Retirement Obligations

In the first quarter of 2015, an updated decommissioning study was completed for the Four Corners coal-fired plant, which resulted in an increase to the asset retirement obligation ("ARO") in the amount of $18 million.

In the second quarter of 2015, there was a revision in estimated cash flows for the Four Corners decommissioning, which resulted in an increase to the ARO in the amount of $6 million. In addition, APS recognized an ARO for Cholla as a result of new CCR environmental rules that were published in the Federal Register in the second quarter of 2015. See Note 8 for additional information related to the CCR environmental rules. This resulted in an increase to the ARO in the amount of $39 million, an increase in plant in service of $23 million and a reduction of the regulatory liability of $16 million.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following schedule shows the change in our asset retirement obligations for the nine months ended September 30, 2015 (dollars in millions):

Asset retirement obligations at January 1, 2015	$391
Changes attributable to:	
Accretion expense	19
Settlements	(27)
Estimated cash flow revisions	24
Newly incurred liabilities	42
Asset retirement obligations at September 30, 2015	$449

Decommissioning activities for Four Corners Units 1-3 began in January 2014; thus, $27 million of the total asset retirement obligation of $449 million at September 30, 2015, is classified as a current liability on the balance sheet.

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.

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

	Three Months Ended September 30,	
	2015	2014
ELECTRIC OPERATING REVENUES	$1,198,380	$1,172,190
OPERATING EXPENSES		
Fuel and purchased power	363,847	382,362
Operations and maintenance	216,011	212,430
Depreciation and amortization	125,592	103,638
Income taxes	148,543	145,217
Taxes other than income taxes	43,149	40,615
Total	897,142	884,262
OPERATING INCOME	301,238	287,928
OTHER INCOME (DEDUCTIONS)		
Income taxes	5,678	4,235
Allowance for equity funds used during construction	7,645	7,038
Other income (Note S-1)	650	2,613
Other expense (Note S-1)	(3,965)	(3,226)
Total	10,008	10,660
INTEREST EXPENSE		
Interest on long-term debt	44,011	44,440
Interest on short-term borrowings	3,460	1,435
Debt discount, premium and expense	1,218	1,020
Allowance for borrowed funds used during construction	(3,492)	(3,479)
Total	45,197	43,416
NET INCOME	266,049	255,172
Less: Net income attributable to noncontrolling interests (Note 6)	4,862	4,125
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$261,187	$251,047

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,	
	2015	2014
NET INCOME	$266,049	$255,172
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax benefit of $96 and $58	(151)	(91)
Reclassification of net realized loss, net of tax benefit of $567 and $3,833	892	5,940
Pension and other postretirement benefits activity, net of tax expense of $553 and $474	870	735
Total other comprehensive income	1,611	6,584
COMPREHENSIVE INCOME	267,660	261,756
Less: Comprehensive income attributable to noncontrolling interests	4,862	4,125
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$262,798	$257,631

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2015	2014
ELECTRIC OPERATING REVENUES	$2,758,771	$2,763,315
OPERATING EXPENSES		
Fuel and purchased power	868,561	923,001
Operations and maintenance	633,989	628,774
Depreciation and amortization	369,234	310,512
Income taxes	232,454	233,067
Taxes other than income taxes	129,258	130,002
Total	2,233,496	2,225,356
OPERATING INCOME	525,275	537,959
OTHER INCOME (DEDUCTIONS)		
Income taxes	10,809	7,013
Allowance for equity funds used during construction	26,214	21,979
Other income (Note S-1)	1,999	8,596
Other expense (Note S-1)	(11,768)	(9,757)
Total	27,254	27,831
INTEREST EXPENSE		
Interest on long-term debt	134,265	141,799
Interest on short-term borrowings	6,339	4,485
Debt discount, premium and expense	3,455	3,085
Allowance for borrowed funds used during construction	(12,019)	(11,039)
Total	132,040	138,330
NET INCOME	420,489	427,460
Less: Net income attributable to noncontrolling interests (Note 6)	14,072	21,976
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$406,417	$405,484

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2015	2014
NET INCOME	$420,489	$427,460
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense of $392 and $566	(926)	(472)
Reclassification of net realized loss, net of tax benefit of $1,490 and $6,417	3,742	11,010
Pension and other postretirement benefits activity, net of tax expense of $1,275 and $252	1,477	18
Total other comprehensive income	4,293	10,556
COMPREHENSIVE INCOME	424,782	438,016
Less: Comprehensive income attributable to noncontrolling interests	14,072	21,976
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$410,710	$416,040

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

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

	September 30, 2015	December 31, 2014
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$15,993,961	$15,539,811
Accumulated depreciation and amortization	(5,534,731)	(5,394,650)
Net	10,459,230	10,145,161
Construction work in progress	749,927	682,807
Palo Verde sale leaseback, net of accumulated depreciation (Note 6)	118,352	121,255
Intangible assets, net of accumulated amortization	134,782	119,600
Nuclear fuel, net of accumulated amortization	137,519	125,201
Total property, plant and equipment	11,599,810	11,194,024
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 12)	712,011	713,866
Assets from risk management activities (Note 7)	15,308	17,620
Other assets	34,201	33,362
Total investments and other assets	761,520	764,848
CURRENT ASSETS		
Cash and cash equivalents	5,346	4,515
Customer and other receivables	361,928	297,712
Accrued unbilled revenues	162,269	100,533
Allowance for doubtful accounts	(3,721)	(3,094)
Materials and supplies (at average cost)	234,987	218,889
Fossil fuel (at average cost)	43,536	37,097
Assets from risk management activities (Note 7)	13,654	13,785
Deferred fuel and purchased power regulatory asset (Note 3)	—	6,926
Other regulatory assets (Note 3)	139,766	129,808
Deferred income taxes	54,837	55,253
Other current assets	37,634	38,693
Total current assets	1,050,236	900,117
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,102,327	1,054,087
Assets for other postretirement benefits (Note 4)	169,899	149,260
Unamortized debt issue costs	27,353	24,642
Other	126,907	128,026
Total deferred debits	1,426,486	1,356,015
TOTAL ASSETS	$14,838,052	$14,215,004

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

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

	September 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$178,162	$178,162
Additional paid-in capital	2,379,696	2,379,696
Retained earnings	2,243,336	1,968,718
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(36,471)	(37,948)
Derivative instruments	(7,569)	(10,385)
Total shareholder equity	4,757,154	4,478,243
Noncontrolling interests (Note 6)	137,668	151,609
Total equity	4,894,822	4,629,852
Long-term debt less current maturities (Note 2)	3,132,347	2,906,215
Total capitalization	8,027,169	7,536,067
CURRENT LIABILITIES		
Short-term borrowings (Note 2)	57,000	147,400
Current maturities of long-term debt (Note 2)	411,433	383,570
Accounts payable	229,017	289,930
Accrued taxes (Note 5)	346,634	131,110
Accrued interest	39,727	52,358
Common dividends payable	—	65,800
Customer deposits	72,455	72,307
Liabilities from risk management activities (Note 7)	74,637	59,676
Liabilities for asset retirements (Note 15)	26,875	32,462
Deferred fuel and purchased power regulatory liability (Note 3)	12,222	—
Other regulatory liabilities (Note 3)	135,970	130,549
Other current liabilities	187,294	167,302
Total current liabilities	1,593,264	1,532,464
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,657,038	2,571,365
Regulatory liabilities (Note 3)	995,757	1,051,196
Liabilities for asset retirements (Note 15)	421,949	358,288
Liabilities for pension benefits (Note 4)	356,616	424,508
Liabilities from risk management activities (Note 7)	96,360	50,602
Customer advances	121,905	123,052
Coal mine reclamation	201,040	198,292
Deferred investment tax credit	188,149	178,607
Unrecognized tax benefits (Note 5)	36,636	45,740
Other	142,169	144,823
Total deferred credits and other	5,217,619	5,146,473
COMMITMENTS AND CONTINGENCIES (SEE NOTES)		
TOTAL LIABILITIES AND EQUITY	$14,838,052	$14,215,004

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$420,489	$427,460
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	428,042	371,651
Deferred fuel and purchased power	(137)	(26,880)
Deferred fuel and purchased power amortization	19,284	31,724
Allowance for equity funds used during construction	(26,214)	(21,979)
Deferred income taxes	72,737	77,435
Deferred investment tax credit	9,542	25,206
Change in derivative instruments fair value	(261)	300
Changes in current assets and liabilities:		
Customer and other receivables	(106,236)	(149,725)
Accrued unbilled revenues	(61,736)	(59,240)
Materials, supplies and fossil fuel	(22,537)	(3,346)
Income tax receivable	—	135,179
Other current assets	2,676	(4,575)
Accounts payable	(52,919)	(10,055)
Accrued taxes	215,524	178,186
Other current liabilities	7,759	55,127
Change in margin and collateral accounts — assets	(1,291)	(474)
Change in margin and collateral accounts — liabilities	30,678	(20,875)
Change in unrecognized tax benefits	(9,276)	1,744
Change in other long-term assets	14,244	(49,635)
Change in other long-term liabilities	(108,410)	(54,940)
Net cash flow provided by operating activities	831,958	902,288
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(778,207)	(618,658)
Contributions in aid of construction	33,982	8,537
Allowance for borrowed funds used during construction	(12,019)	(11,039)
Proceeds from nuclear decommissioning trust sales	330,304	269,276
Investment in nuclear decommissioning trust	(343,488)	(282,212)
Other	(840)	339
Net cash flow used for investing activities	(770,268)	(633,757)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	600,000	574,126
Short-term borrowings — net	(90,400)	(133,975)
Repayment of long-term debt	(344,847)	(503,583)
Dividends paid on common stock	(197,600)	(187,800)
Noncontrolling interests	(28,012)	(15,869)
Net cash flow used for financing activities	(60,859)	(267,101)
NET INCREASE IN CASH AND CASH EQUIVALENTS	831	1,430
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4,515	3,725

CASH AND CASH EQUIVALENTS AT END OF PERIOD	$5,346	$5,155
Supplemental disclosure of cash flow information		
Cash paid (received) during the period for:		
Income taxes, net of refunds	$5,504	$(119,440)
Interest, net of amounts capitalized	$141,216	$142,364
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$36,718	$24,135

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to Arizona Public Service Company's Condensed Consolidated Financial Statements.

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

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Shares	Amount					
Balance, January 1, 2014	71,264,947	$178,162	$2,379,696	$1,804,398	$(53,372)	$145,990	$4,454,874
Net income		—	—	405,484	—	21,976	427,460
Other comprehensive income		—	—	—	10,556	—	10,556
Dividends on common stock		—	—	(125,300)	—	—	(125,300)
Net capital activities by noncontrolling interests		—	—	—	—	(15,869)	(15,869)
Balance, September 30, 2014	71,264,947	$178,162	$2,379,696	$2,084,582	$(42,816)	$152,097	$4,751,721
Balance, January 1, 2015	71,264,947	$178,162	$2,379,696	$1,968,718	$(48,333)	$151,609	$4,629,852
Net income		—	—	406,417	—	14,072	420,489
Other comprehensive income		—	—	—	4,293	—	4,293
Dividends on common stock		—	—	(131,800)	—	—	(131,800)
Other		—	—	1	—	—	1
Net capital activities by noncontrolling interests		—	—	—	—	(28,013)	(28,013)
Balance, September 30, 2015	71,264,947	$178,162	$2,379,696	$2,243,336	$(44,040)	$137,668	$4,894,822

See Notes to Pinnacle West's Condensed Consolidated Financial Statements and Supplemental Notes to APS's Condensed Consolidated Financial Statements.

Certain notes to APS's Condensed Consolidated Financial Statements are combined with the Notes to Pinnacle West's Condensed Consolidated Financial Statements. Listed below are the Condensed Consolidated Notes to Pinnacle West's Condensed Consolidated Financial Statements, the majority of which also relate to APS's Condensed Consolidated Financial Statements. In addition, listed below are the Supplemental Notes that are required disclosures for APS and should be read in conjunction with Pinnacle West's Condensed Consolidated Notes.

	Condensed Consolidated Note Reference		APS's Supplemental Note Reference	
Consolidation and Nature of Operations	Note	1	—	
Long-Term Debt and Liquidity Matters	Note	2	—	
Regulatory Matters	Note	3	—	
Retirement Plans and Other Benefits	Note	4	—	
Income Taxes	Note	5	—	
Palo Verde Sale Leaseback Variable Interest Entities	Note	6	—	
Derivative Accounting	Note	7	—	
Commitments and Contingencies	Note	8	—	
Other Income and Other Expense	Note	9	Note	S-1
Earnings Per Share	Note	10	—	
Fair Value Measurements	Note	11	—	
Nuclear Decommissioning Trusts	Note	12	—	
New Accounting Standards	Note	13	—	
Changes in Accumulated Other Comprehensive Loss	Note	14	Note	S-2
Asset Retirement Obligations	Note	15	—	

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

S-1. Other Income and Other Expense

The following table provides detail of APS's other income and other expense for the three and nine months ended September 30, 2015 and 2014 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Other income:				
Interest income	$32	$31	$105	$585
Gain on disposition of property	(58)	91	627	736
Miscellaneous	676	2,491	1,267	7,275
Total other income	$650	$2,613	$1,999	$8,596
Other expense:				
Non-operating costs (a)	$(2,248)	$(2,298)	$(6,643)	$(7,753)
Loss on disposition of property	(327)	(98)	(934)	(565)
Miscellaneous	(1,390)	(830)	(4,191)	(1,439)
Total other expense	$(3,965)	$(3,226)	$(11,768)	$(9,757)

(a) As defined by FERC, includes below-the-line non-operating utility expense (items excluded from utility rate recovery).

ARIZONA PUBLIC SERVICE COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

S-2. Changes in Accumulated Other Comprehensive Loss

The following tables show the changes in accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three and nine months ended September 30, 2015 and 2014 (dollars in thousands):

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Balance at beginning of the period	$(45,651)	$(49,400)	$(48,333)	$(53,372)
Derivative Instruments				
OCI (loss) before reclassifications	(151)	(91)	(926)	(472)
Amounts reclassified from accumulated other comprehensive loss (a)	892	5,940	3,742	11,010
Net current period OCI (loss)	741	5,849	2,816	10,538
Pension and Other Postretirement Benefits				
OCI (loss) before reclassifications	—	—	(927)	(2,041)
Amounts reclassified from accumulated other comprehensive loss (b)	870	735	2,404	2,059
Net current period OCI (loss)	870	735	1,477	18
Ending balance, September 30	$(44,040)	$(42,816)	$(44,040)	$(42,816)

(a) These amounts represent realized gains and losses and are included in the computation of fuel and purchased power costs and are subject to the PSA. See Note 7.

(b) These amounts primarily represent amortization of actuarial loss and are included in the computation of net periodic pension cost. See Note 4.

ITEM 2. 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 Condensed Consolidated Financial Statements and APS’s Condensed Consolidated Financial Statements and the related Notes that appear in Item 1 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 Part 1, Item 1A of the 2014 Form 10-K.

OVERVIEW

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

Areas of Business Focus

Operational Performance, Reliability and Recent Developments.

Nuclear. APS operates and is a joint owner of Palo Verde. The March 2011 earthquake and tsunamis in Japan and the resulting accident at Japan’s Fukushima Daiichi nuclear power station had a significant impact on nuclear power operators worldwide. In the aftermath of the accident, the NRC conducted an independent assessment to consider actions to address lessons learned from the Fukushima events. The independent assessment, named the "Near Term Task Force," recommended a number of proposed enhancements to U.S. commercial nuclear power plant equipment and emergency plans. The NRC has directed nuclear power plants to begin implementing some of the Near Term Task Force’s recommendations. To implement these recommendations, Palo Verde expects to spend approximately $11 million for capital enhancements to the plant through 2016 in addition to the approximate $120 million that has already been spent on capital enhancements as of September 30, 2015 (APS’s share is 29.1%).

Coal and Related Environmental Matters and Transactions. APS is a joint owner of three coal-fired power plants and acts as operating agent for two of the plants. APS is focused on the impacts on its coal fleet that may result from increased regulation and potential legislation concerning GHG emissions. On June 2, 2014, EPA proposed a rule to limit carbon dioxide emissions from existing power plants (the "Clean Power Plan"), and EPA finalized its proposal on August 3, 2015.

EPA’s nationwide CO_2 emissions reduction goal is 32% below 2005 emission levels. As finalized for the state of Arizona and the Navajo Nation, the Clean Power Plan could force a shift in generation from coal to natural gas and renewable generation. Until implementation plans for these jurisdictions are finalized, we are unable to determine the actual impacts to APS. We expect that our closure of Cholla Unit 2, described below, and our plans to cease burning coal at the other APS-owned units at Cholla (Units 1 and 3) by the mid-2020s, together with prior unit retirements at Four Corners, will help to facilitate compliance with the Clean Power Plan. APS continually analyzes its long-range capital management plans to assess the potential effects of these changes, understanding that any resulting regulation and legislation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to continue participation in such plants.

58

Cholla

On September 11, 2014, APS announced that it will close its 260 megawatt Unit 2 at Cholla by April 2016 and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. (See Note 3 for details related to the resulting regulatory asset and Note 8 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long term than the benefits that would have resulted from adding the emissions control equipment. APS closed Unit 2 on October 1, 2015.

Four Corners

Asset Purchase Agreement and Coal Supply Matters. On December 30, 2013, APS purchased SCE's 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. In connection with APS's most recent retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS's acquisition of SCE's interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustments was appealed. APS has intervened and is actively participating in the proceeding. We cannot predict when or how this appeal will be resolved; however, the eventual outcome of the SIB matter discussed below could have an effect on the outcome of this proceeding.

Concurrently with the closing of the SCE transaction, BHP Billiton New Mexico Coal, Inc. ("BHP Billiton"), the parent company of BHP Navajo Coal Company ("BNCC"), the coal supplier and operator of the mine that serves Four Corners, transferred its ownership of BNCC to Navajo Transitional Energy Company, LLC ("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.

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

Lease Extension. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the United States Department of the Interior ("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. The record of decision provides the authority for the Bureau of Indian Affairs to sign the lease amendments and rights-of-way renewals, which occurred in late July 2015.

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo is a 330 MW 4-unit gas plant located in Tempe, Arizona. 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. During the ACC's Integrated Resource Planning meeting in the fall of 2014, there was clear understanding of the need to replace the existing steam units, but questions were raised on the cost effectiveness of the additional three units. To address these matters, APS issued a request for proposal ("RFP") in late January 2015 for the incremental capacity, equivalent to 3 of the 5 units. Bids were due in March and have been analyzed by APS. An independent monitor was involved throughout the entire RFP process. The RFP affirmed that APS's bid at the existing Ocotillo site was the most cost effective while it also demonstrated that a target completion date of 2019 was most appropriate (instead of 2018 as originally planned).

Transmission and Delivery. APS is working closely with regulators to identify and plan for transmission needs that continue to support system reliability, access to markets and renewable energy development. The capital expenditures table presented in the "Liquidity and Capital Resources" section below includes new APS transmission projects through 2017, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand smart grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better monitor their energy use and needs, minimize system outage durations, as well as the number of customers that experience outages, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions, including remote meter reading and remote connects and disconnects.

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

On July 12, 2013, APS filed its annual RES implementation plan, covering the 2014-2018 timeframe and requesting a 2014 RES budget of approximately $143 million. In a final order dated January 7, 2014, the ACC approved the requested budget. Also in 2013, the ACC conducted a hearing to consider APS’s proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a

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

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

On July 1, 2015, APS filed its 2016 RES implementation plan and proposed a RES budget of approximately $148 million.

The following table summarizes renewable energy sources in APS's renewable portfolio that are in operation and under development as of October 30, 2015.

	Net Capacity in Operation (MW)	Net Capacity Planned / Under Development (MW)
Total APS Owned: Solar (a)	189	9
Purchased Power Agreements:		
Solar	310	—
Wind	289	—
Geothermal	10	—
Biomass	14	—
Biogas	6	—
Total Purchased Power Agreements	629	—
Total Distributed Energy: Solar (b)	437	36 (c)
Total Renewable Portfolio	1,255	45

(a) Included in the 189 MW number is 170 MW of solar resources procured through the AZ Sun Program.
(b) Includes rooftop solar facilities owned by third parties. Distributed generation is produced in DC and is converted to AC for reporting purposes.
(c) Applications received by APS that are not yet installed and online.

APS is developing owned solar resources through the ACC-approved AZ Sun Program. Under this program to date, APS estimates its investment commitment will be approximately $675 million. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the project to the electric grid.

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

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

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

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

On March 20, 2015, APS filed an application with the ACC requesting a budget of $68.9 million for 2015 and minor modifications to its DSM portfolio going forward, including for the first time three resource savings projects which reflect energy savings on APS's system. Consistent with the ACC's March 11, 2014 order, APS intends to continue its other approved DSM programs in 2015.

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

Electric Energy Efficiency. On June 27, 2013, the ACC voted to open a new docket investigating whether the Electric Energy Efficiency Standards should be modified. The ACC held a series of three workshops in March and April 2014 to investigate methodologies used to determine cost effective energy efficiency programs, cost recovery mechanisms, incentives, and potential changes to the Electric Energy Efficiency and Resource Planning Rules.

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

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

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

As part of APS's acquisition of SCE's interest in Units 4 and 5 of Four Corners, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. APS and SCE continue to evaluate potential paths forward. APS believes that the original denial by FERC of rate recovery under the Transmission Termination Agreement constitutes the failure of a condition that relieves APS of its obligations under that agreement. If APS and SCE are unable to determine a resolution through negotiation, the Transmission Termination Agreement requires that disputes be resolved through arbitration. APS is unable to predict the outcome of this matter if it proceeds to arbitration. If the matter proceeds to arbitration and APS is not successful, APS may be required to record a charge to its results of operations.

Net Metering. On July 12, 2013, APS filed an application with the ACC proposing a solution to address the cost shift brought by the current net metering rules. On December 3, 2013, the ACC issued its order on APS's net metering proposal. The ACC instituted a charge on customers who install rooftop solar panels after December 31, 2013. The charge of $0.70 per kilowatt became effective on January 1, 2014, and is estimated to collect $4.90 per month from a typical future rooftop solar customer to help pay for their use of the electricity grid. The fixed charge does not increase APS's revenue because it is credited to the LFCR.

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electrical grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift. In its December 2013 order, the ACC directed APS to provide quarterly reports on the pace of rooftop solar adoption to assist the ACC in considering further increases.

On April 2, 2015, APS filed an application with the ACC seeking to increase the fixed grid access charge to $3.00 per kilowatt, or approximately $21 per month for a typical new residential solar customer, effective August 1. In August 2015, the ACC ordered that a hearing be held to evaluate the merits of APS's April proposal. APS subsequently requested that the ACC redirect its focus to APS's cost to serve customers with rooftop solar and offered to withdraw its request to reset the grid access charge if such a cost of service proceeding could be expeditiously conducted.

On October 20, 2015, the ACC voted to rescind their earlier decision to hold a hearing regarding APS's request, dismissed APS's request to increase its grid access charge, and closed the docket in which the request was filed. The ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information which will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A procedural conference will be held to determine both a schedule for the hearing and the scope of the issues to be discussed at hearing. APS cannot predict the outcome of this proceeding.

Appellate Review of Third-Party Regulatory Decision ("System Improvement Benefits" or "SIB"). In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the “fair value” of a utility’s property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC’s method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC has sought review by the Arizona Supreme Court of this decision. If the Supreme Court declines to review the case, or the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may be negatively impacted and may no longer operate as they do currently. This could in turn have a significant impact on APS’ ability to recover certain costs in between rate cases. APS intends to support the ACC’s petition to the Supreme Court for review of the Court of Appeals’ decision, but cannot predict the outcome of this matter.

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

Other Subsidiaries.

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

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

Key Financial Drivers

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

Electric Operating Revenues. For the years 2012 through 2014, retail electric revenues comprised approximately 93% of our total electric operating revenues. Our electric operating revenues are affected by customer growth or decline, variations in weather from period to period, customer mix, average usage per customer and the impacts of energy efficiency programs, distributed energy additions, electricity rates and tariffs, the recovery of PSA deferrals and the operation of other recovery mechanisms. These revenue transactions are affected by the availability of excess generation or other energy resources and wholesale market conditions, including competition, demand and prices.

Customer and Sales Growth. Retail customers in APS’s service territory increased 1.2% for the nine-month period ended September 30, 2015 compared with the prior-year period. For the three years 2012 through 2014, APS’s customer growth averaged 1.3% per year. We currently expect annual customer growth

to average in the range of 2.0-3.0% for 2015 through 2017 based on our assessment of modestly improving economic conditions in Arizona. Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 0.7% for the nine-month period ended September 30, 2015 compared with the prior-year period, reflecting the effects of improving economic conditions and customer growth, partially offset by customer conservation and energy efficiency and distributed renewable generation initiatives. For the three years 2012 through 2014, APS experienced annual decreases in retail electricity sales averaging 0.2%, adjusted to exclude the effects of weather variations. We currently estimate that annual retail electricity sales in kWh will increase on average in the range of 0.5-1.5% during 2015 through 2017, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy could further impact these estimates.

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

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

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

Operations and Maintenance Expenses. Operations and maintenance expenses are impacted by customer and sales growth, power plant operations, maintenance of utility plant (including generation, transmission, and distribution facilities), inflation, outages, renewable energy and demand side management related expenses (which are offset by the same amount of operating revenues) and other factors. On September 30, 2014, Pinnacle West announced plan design changes to the group life and medical postretirement benefit plan, which reduced net periodic benefit costs. See Note 4.

Depreciation and Amortization Expenses. Depreciation and amortization expenses are impacted by net additions to utility plant and other property (such as new generation, transmission, and distribution facilities), and changes in depreciation and amortization rates. See "Capital Expenditures" below for information regarding the planned additions to our facilities. See Note 3 regarding deferral of certain costs pursuant to an ACC order.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 10.7% of the assessed value for 2014 and 10.5% for 2013. We expect property taxes to increase as we add new generating units and continue with improvements and expansions to our existing generating units, transmission and distribution facilities. (See Note 3 for property tax deferrals contained in the 2012 Settlement Agreement).

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

Interest Expense. Interest expense is affected by the amount of debt outstanding and the interest rates on that debt (see Note 2). 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 retail and wholesale sales supplied to traditional cost-based rate regulation ("Native Load") customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results — Three-month period ended September 30, 2015 compared with three-month period ended September 30, 2014.

Our consolidated net income attributable to common shareholders for the three months ended September 30, 2015 was $257 million, compared with consolidated net income of $244 million for the prior-year period. The results reflect an increase of approximately $13 million for the regulated electricity segment primarily due to the Four Corners-related rate change, higher retail sales due to customer growth and changes in customer usage patterns and related pricing, and the effects of weather, partially offset by higher depreciation and amortization.

The following table presents net income attributable to common shareholders compared with the prior-year period:

	Three Months Ended September 30,		
	2015	2014	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$835	$790	$45
Operations and maintenance	(220)	(223)	3
Depreciation and amortization	(126)	(104)	(22)
Taxes other than income taxes	(43)	(41)	(2)
All other income and expenses, net	2	5	(3)
Interest charges, net of allowance for borrowed funds used during construction	(46)	(44)	(2)
Income taxes	(140)	(135)	(5)
Less income related to noncontrolling interests (Note 6)	(5)	(4)	(1)
Regulated electricity segment net income	257	244	13
All other	—	—	—
Net Income Attributable to Common Shareholders	$257	$244	$13

66

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $45 million higher for the three months ended September 30, 2015 compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Four Corners-related rate change	$20	$—	$20
Higher retail sales due to customer growth and changes in customer usage patterns and related pricing	21	6	15
Effects of weather	10	3	7
Lost fixed cost recovery	4	—	4
Changes in long-term wholesale contracted sales	(12)	(8)	(4)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(22)	(22)	—
Miscellaneous items, net	5	2	3
Total	$26	$(19)	$45

Operations and maintenance. Operations and maintenance expenses decreased $3 million for the three months ended September 30, 2015 compared with the prior-year period primarily because of:

- A decrease of $8 million for costs related to corporate support;
- An increase of $6 million for employee benefit costs primarily related to stock compensation; and
- A decrease of $1 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $22 million higher for the three months ended September 30, 2015 compared with the prior-year period primarily related to:

- An increase of $9 million related to the absence of 2014 Four Corners cost deferrals;
- An increase of $7 million due to increased plant in service; and
- An increase of $6 million related to the 2015 amortization of the Four Corners cost deferrals and acquisition adjustment.

Income Taxes. Income taxes were $5 million higher for the three months ended September 30, 2015 compared with the prior-year period, primarily because of higher taxable income in the current year.

Operating Results — Nine-month period ended September 30, 2015 compared with nine-month period ended September 30, 2014.

Our consolidated net income attributable to common shareholders for the nine months ended September 30, 2015 was $396 million, compared with consolidated net income of $392 million for the prior-year period. The results reflect an increase of approximately $5 million for the regulated electricity segment primarily due to the Four Corners-related rate change, higher retail sales due to customer growth and changes in customer usage patterns and related pricing, and lower interest charges, partially offset by higher depreciation and amortization.

The following table presents net income attributable to common shareholders compared with the prior-year period:

	Nine Months Ended September 30,		
	2015	2014	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$1,890	$1,840	$50
Operations and maintenance	(646)	(647)	1
Depreciation and amortization	(369)	(310)	(59)
Taxes other than income taxes	(129)	(131)	2
All other income and expenses, net	16	20	(4)
Interest charges, net of allowance for borrowed funds used during construction	(134)	(141)	7
Income taxes	(216)	(216)	—
Less income related to noncontrolling interests (Note 6)	(14)	(22)	8
Regulated electricity segment net income	398	393	5
All other	(2)	(1)	(1)
Net Income Attributable to Common Shareholders	$396	$392	$4

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $50 million higher for the nine months ended September 30, 2015 compared with the prior-year period. The following table summarizes the major components of this change:

	Increase (Decrease)		
	Operating revenues	Fuel and purchased power expenses	Net change
	(dollars in millions)		
Four Corners-related rate change	$46	$—	$46
Higher retail sales due to customer growth and changes in customer usage patterns and related pricing	16	5	11
Lost fixed cost recovery	10	—	10
Effects of weather	5	2	3
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(46)	(45)	(1)
Changes in long-term wholesale contracted sales	(32)	(20)	(12)
Miscellaneous items, net	(4)	3	(7)
Total	$(5)	$(55)	$50

Operations and maintenance. Operations and maintenance expenses decreased $1 million for the nine months ended September 30, 2015 compared with the prior-year period primarily because of:

- A decrease of $16 million for employee benefit costs primarily related to lower postretirement benefit costs;
- A decrease of $8 million for costs related to corporate support;
- A decrease of $8 million related to costs for demand-side management, renewable energy and similar regulatory programs, which were partially offset in operating revenues and purchased power;
- An increase of $13 million in fossil generation costs primarily related to increased outage costs;
- An increase of $9 million related to higher nuclear generation costs;
- An increase of $7 million in energy delivery and customer service costs including costs related to a new customer information system; and
- An increase of $2 million related to other miscellaneous factors.

Depreciation and amortization. Depreciation and amortization expenses were $59 million higher for the nine months ended September 30, 2015 compared with the prior-year period primarily related to:

- An increase of $19 million related to the absence of 2014 Four Corners cost deferrals;
- An increase of $17 million related to the 2015 amortization of the Four Corners cost deferrals and acquisition adjustment;

- An increase of $16 million due to increased plant in service;
- An increase of $10 million related to the regulatory treatment of the Palo Verde sale leaseback, which is offset in noncontrolling interests; and
- A decrease of $3 million due to other miscellaneous factors.

Interest charges, net of allowance for borrowed funds used during construction. Interest charges, net of allowance for borrowed funds used during construction, decreased $7 million for the nine months ended September 30, 2015 compared with the prior-year period, primarily because of lower interest rates in the current year.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At September 30, 2015, APS's common equity ratio, as defined, was 56%. Its total shareholder equity was approximately $4.8 billion, and total capitalization was approximately $8.5 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS's total capitalization remains the same. This restriction does not materially affect Pinnacle West's ability to meet its ongoing cash needs or ability to pay dividends to shareholders.

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.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the nine months ended September 30, 2015 and 2014 (dollars in millions):

Pinnacle West Consolidated

	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	Net Change
Net cash flow provided by operating activities	$821	$887	$(66)
Net cash flow used for investing activities	(773)	(634)	(139)
Net cash flow used for financing activities	(43)	(252)	209
Net increase in cash and cash equivalents	$5	$1	$4

Arizona Public Service Company

	Nine Months Ended September 30,		Net
	2015	2014	Change
Net cash flow provided by operating activities	$832	$902	$(70)
Net cash flow used for investing activities	(770)	(634)	(136)
Net cash flow used for financing activities	(61)	(267)	206
Net increase in cash and cash equivalents	$1	$1	$—

Operating Cash Flows

Nine-month period ended September 30, 2015 compared with nine-month period ended September 30, 2014. Pinnacle West's consolidated net cash provided by operating activities was $821 million in 2015 compared to $887 million in 2014, a decrease of $66 million in net cash provided. The decrease is primarily related to a $135 million income tax refund received in the first quarter of 2014. The decrease is partially offset by a $51 million change in cash collateral posted, and other changes in working capital.

Other. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 118% funded as of January 1, 2014 and 116% funded as of January 1, 2015. Under GAAP, the qualified pension plan was 90% funded as of January 1, 2014 and 89% funded as of January 1, 2015. 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 have made voluntary contributions of $100 million to our pension plan year-to-date in 2015. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions totaling up to $200 million for the next two years (up to $100 million each year in 2016 and 2017). We expect to make contributions of approximately $1 million in each of the next three years to our other postretirement benefit plans.

Investing Cash Flows

Nine-month period ended September 30, 2015 compared with nine-month period ended September 30, 2014. Pinnacle West's consolidated net cash used for investing activities was $773 million in 2015, compared to $634 million in 2014, an increase of $139 million in net cash used primarily related to increased capital expenditures.

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,		
	2015	2016	2017
APS			
Generation:			
Nuclear Fuel	$78	$86	$78
Renewables	66	13	1
Environmental	47	234	198
New Gas Generation	66	77	258
Other Generation	181	144	172
Distribution	336	347	317
Transmission	193	125	180
Other (a)	89	85	81
Total APS	$1,056	$1,111	$1,285

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil and nuclear plants. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment, such as turbines, boilers and environmental equipment. The estimated Renewables expenditures include 20 MW of utility-scale solar projects which were approved by the ACC in the 2014 RES Implementation Plan. We have not included estimated costs for Cholla's compliance with MATS or EPA's regional haze rule since we have challenged the regional haze rule judicially and we have proposed a compromise strategy to EPA, which, if approved, would allow us to avoid expenditures related to environmental control equipment. The portion of estimated costs through 2017 for installation of pollution control equipment needed to ensure Four Corners' compliance with EPA's regional haze rules have been included in the table above. The portion of estimated costs through 2017 for incremental costs to comply with the CCR rule for Four Corners and Cholla have also been included in the table above. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. The table above does not include capital expenditures related to El Paso's 7% interest in Four Corners Units 4 and 5 of $3 million in 2015, $27 million in 2016 and $20 million in 2017. We are monitoring the status of other environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

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

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

Nine-month period ended September 30, 2015 compared with nine-month period ended September 30, 2014. Pinnacle West's consolidated net cash used for financing activities was $43 million in 2015, compared to $252 million of net cash used in 2014, a decrease of $209 million in net cash used. The decrease in net cash used for financing activities is primarily due to $159 million lower repayments of long-term debt, a $44 million net change in short-term borrowings, and $26 million higher issuances of long-term debt.

Significant Financing Activities. On October 21, 2015, the Pinnacle West Board of Directors declared a dividend of $0.625 per share of common stock, payable on December 1, 2015 to shareholders of record on November 2, 2015. This represents an increase in the indicated annual dividend from $2.38 per share to $2.50 per share.

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

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

On May 28, 2015, APS purchased all $32 million of Maricopa County, Arizona Pollution Control Corporation Pollution Control Revenue Refunding Bonds, 2009 Series B, due 2029 in connection with the mandatory tender provisions for this indebtedness.

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

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

On October 27, 2015, notice was given that all Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A, approximately $38 million in principal amount, have been called for optional redemption on November 17, 2015. These bonds are classified as current maturities of long-term debt on our Condensed Consolidated Balance Sheets at September 30, 2015.

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.

Pinnacle West's $200 million revolving credit facility matures in May 2019. At September 30, 2015, the facility was available to refinance indebtedness of the Company and for other general corporate purposes, including credit support for its $200 million commercial paper program. Pinnacle West has the option to increase the size of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At September 30, 2015, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and no commercial paper borrowings.

At September 30, 2015, APS had two credit facilities totaling $1 billion, including a $500 million credit facility that matures in September 2020 and a $500 million facility that matures in May 2019. APS may increase the size of each facility up to a maximum of $700 million upon the satisfaction of certain conditions and with the consent of the lenders. APS will use these facilities to refinance indebtedness and for other general corporate purposes. Interest rates are based on APS's senior unsecured debt credit ratings.

The facilities described above are available to support APS's $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At September 30, 2015, APS had $57 million of commercial paper outstanding and no outstanding borrowings or letters of credit under these credit facilities.

See "Financial Assurances" in Note 8 for a discussion of APS's separate outstanding letters of credit.

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

See Note 7 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 September 30, 2015, the ratio was approximately 46% for Pinnacle West and 44% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could "cross-default" other debt. See further discussion of "cross-default" provisions below.

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

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 2 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of October 23, 2015 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

	Moody's	Standard & Poor's	Fitch
Pinnacle West			
Corporate credit rating	A3	A-	A-
Commercial paper	P-2	A-2	F2
Outlook	Stable	Stable	Stable
APS			
Corporate credit rating	A2	A-	A-
Senior unsecured	A2	A-	A
Secured lease obligation bonds	A2	A-	A
Commercial paper	P-1	A-2	F2
Outlook	Stable	Stable	Stable

Off-Balance Sheet Arrangements

See Note 6 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

Contractual Obligations

During 2015, our purchase obligations increased by about $170 million relating to gas generation projects at our Ocotillo plant and $359 million relating to selective catalytic reduction control technologies at our Four Corners Plant. The expected payments to be made relating to these additional purchase obligations are $42 million in 2015, $269 million in 2016, $176 million in 2017, and $42 million in 2018.

Other than the items described above, there have been no material changes, as of September 30, 2015, outside the normal course of business in contractual obligations from the information provided in our 2014 Form 10-K. See Note 2 for discussion regarding changes in our long-term debt obligations.

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. There have been no changes to our critical accounting policies since our 2014 Form 10-K. See "Critical Accounting Policies" in Item 7 of the 2014 Form 10-K for further details about our critical accounting policies.

OTHER ACCOUNTING MATTERS

We are currently evaluating the impacts of adopting two new accounting standards: consolidation analysis guidance that will be adopted on January 1, 2016, and revenue recognition guidance that will be effective for us on January 1, 2018. Additionally, new guidance relating to balance sheet presentation of debt issuance costs will be effective for us during the first quarter of 2016. See Note 13.

MARKET AND CREDIT RISKS

Market Risks

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

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 11 and Note 12) and benefit plan assets. The nuclear decommissioning trust fund and benefit plan assets also have risks associated with the changing market value of their equity and other non-fixed income investments. Nuclear decommissioning and benefit plan costs are recovered in regulated electricity prices.

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 for the nine months ended September 30, 2015 and 2014 (dollars in millions):

	Nine Months Ended September 30, 2015	2014
Mark-to-market of net positions at beginning of year	$(115)	$(73)
Increase in regulatory asset/liability	(39)	—
Recognized in OCI:		
Mark-to-market losses realized during the period	5	17
Change in valuation techniques	—	—
Mark-to-market of net positions at end of period	$(149)	$(56)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at September 30, 2015 by maturities and by the type of valuation that is performed to calculate the fair values, classified in their entirety based on the lowest level of input that is significant to the fair value measurement. See Note 1, "Derivative Accounting" and "Fair Value Measurements," in Item 8 of our 2014 Form 10-K and Note 11 for more discussion of our valuation methods.

Source of Fair Value	2015	2016	2017	2018	2019	Years thereafter	Total fair value
Observable prices provided by other external sources	$(14)	$(50)	$(32)	$(12)	$—	$—	$(108)
Prices based on unobservable inputs	(2)	(13)	(10)	(8)	(6)	(2)	(41)
Total by maturity	$(16)	$(63)	$(42)	$(20)	$(6)	$(2)	$(149)

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 Condensed Consolidated Balance Sheets at September 30, 2015 and December 31, 2014 (dollars in millions):

	September 30, 2015 Gain (Loss)		December 31, 2014 Gain (Loss)	
	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in:				
Regulatory asset (liability) or OCI (a)				
Electricity	$2	$(2)	$3	$(3)
Natural gas	33	(33)	29	(29)
Total	$35	$(35)	$32	$(32)

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

Credit Risk

We are exposed to losses in the event of non-performance or non-payment by counterparties. See Note 7 for a discussion of our credit valuation adjustment policy.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Key Financial Drivers" and "Market and Credit Risks" in Item 2 above for a discussion of quantitative and qualitative disclosures about market risks.

Item 4. CONTROLS AND PROCEDURES

(a) Disclosure Controls and Procedures

The term "disclosure controls and procedures" means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") (15 U.S.C. 78a et seq.), is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to a company's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Pinnacle West's management, with the participation of Pinnacle West's Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of Pinnacle West's disclosure controls and procedures as of September 30, 2015. Based on that evaluation, Pinnacle West's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, Pinnacle West's disclosure controls and procedures were effective.

APS's management, with the participation of APS's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of APS's disclosure controls and procedures as of September 30, 2015. Based on that evaluation, APS's Chief Executive Officer and Chief Financial Officer have concluded that, as of that date, APS's disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

The term "internal control over financial reporting" (defined in SEC Rule 13a-15(f)) refers to the process of a company that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

No change in Pinnacle West's or APS's internal control over financial reporting occurred during the fiscal quarter ended September 30, 2015 that materially affected, or is reasonably likely to materially affect, Pinnacle West's or APS's internal control over financial reporting.

PART II -- OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See "Business of Arizona Public Service Company — Environmental Matters" in Item 1 of the 2014 Form 10-K with regard to pending or threatened litigation and other disputes.

See Note 3 for ACC and FERC-related matters.

See Note 8 for information regarding environmental matters, Superfund-related matters, matters related to a September 2011 power outage and a New Mexico tax matter.

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A — Risk Factors in the 2014 Form 10-K, which could materially affect the business, financial condition, cash flows or future results of Pinnacle West and APS. The risks described in the 2014 Form 10-K are not the only risks facing Pinnacle West and APS. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect the business, financial condition, cash flows and/or operating results of Pinnacle West and APS. The risk factor below is an update to our 2014 Form 10-K.

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

APS is subject to comprehensive regulation by several federal, state and local regulatory agencies that significantly influence its business, liquidity, results of operations and its ability to fully recover costs from utility customers in a timely manner. The ACC regulates APS's retail electric rates and FERC regulates rates for wholesale power sales and transmission services. The profitability of APS is affected by the rates it may charge and the timeliness of recovering costs incurred through its rates. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings and ancillary matters which may come before the ACC and FERC, including in some cases how court challenges to these regulatory decisions are resolved. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify otherwise final orders under certain circumstances.

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

The ACC must also approve APS's issuance of securities and any significant transfer or encumbrance of APS property used to provide retail electric service, and must approve or receive prior notification of certain transactions between us, APS and our respective affiliates. Decisions made by the ACC or FERC could have a material adverse impact on our financial condition, results of operations or cash flows.

In a recent appellate challenge to an ACC rate decision regarding a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the "fair value" of a utility's property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC's method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery

of capital and certain other utility costs through adjustors. The ACC has sought review by the Arizona Supreme Court of this decision. If the Supreme Court declines to review the case, or the decision is upheld by the Supreme Court without modification, certain APS rate adjustors may be negatively impacted and may no longer operate as they do currently. This could in turn have a significant impact on APS' ability to recover certain costs in between rate cases. APS intends to support the ACC's petition to the Supreme Court for review of the Court of Appeals' decision, but cannot predict the outcome of this matter.

Item 5. OTHER INFORMATION

Environmental Matters

Greenhouse Gas Emissions

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 NSR analysis for new major sources and major modifications to existing plants.

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

EPA's final rules require newly built fossil fuel-fired EGUs, along with those undergoing modification or reconstruction, to meet CO_2 performance standards based on a combination of best operating practices and equipment upgrades. EPA established separate performance standards for two types of EGUs: stationary combustion turbines, typically natural gas; and electric utility steam generating units, typically coal. We cannot currently predict how the final rules or standards for new, modified, or reconstructed fossil-fired EGUs might impact the Company.

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

In addition to the on-going state proceedings aimed at developing an Arizona compliance plan, EPA is taking comment on proposed model rules and a proposed federal implementation plan, including as to how the Clean Power Plan will apply to EGUs on tribal land. Because Four Corners and the Navajo Plant, in which APS has ownership interests, are located on Navajo Nation land, the FIP will determine how the final Clean Power Plan regulations will affect APS. There are a number of variables that remain in flux (e.g., whether Arizona will calculate compliance on a mass versus a rate basis, and whether and/or how the Clean Power Plan will affect EGUs within the Navajo Nation). Depending on how these variables are resolved in the final FIP, certain EGUs within our region may be required to curtail operations while others may be allowed to operate on a business as usual basis. As such, APS continues to advocate for Clean Power Plan compliance options

that provide our EGUs with the maximum in operational flexibility. Depending on the outcome from these efforts, a substantial change in APS's generation portfolio may be necessary. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

EPA Environmental Regulation

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

Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone national ambient air quality standards (“NAAQS”) at a level of 70 parts per billion (“ppb”). With ozone standards becoming more stringent, our fossil generation units will come under increasing pressure to reduce emissions of nitrogen oxides and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA is expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. Depending on when EPA approves attainment designations for the Arizona and Navajo Nation jurisdictions in which our fossil generation units are located, revisions to SIPs and FIPs, respectively, implementing required controls to achieve the new 70 ppb standard are expected to be in place between 2020 and 2021. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS.

Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
10.1	Pinnacle West APS	Five-Year Credit Agreement dated as of September 2, 2015, among APS, as Borrower, Barclays Bank PLC, as Agent and Issuing Bank, and the lenders and other parties thereto
10.2	Pinnacle West APS	Amendment No. 4, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Emerson Finance LLC, as Lessor, and APS, as Lessee
10.3	Pinnacle West APS	Amendment No. 3, dated as of September 30, 2015, to Facility Lease, dated as of August 1, 1986, between U.S. Bank National Association, successor to State Street Bank and Trust Company, as successor to The First National Bank of Boston, as Owner Trustee under a Trust Agreement with Security Pacific Capital Leasing Corporation, as Lessor, and APS, as Lessee
12.1	Pinnacle West	Ratio of Earnings to Fixed Charges
12.2	APS	Ratio of Earnings to Fixed Charges
12.3	Pinnacle West	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements
31.1	Pinnacle West	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.2	Pinnacle West	Certificate of James R. Hatfield, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended

31.3	APS	Certificate of Donald E. Brandt, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
31.4	APS	Certificate of James R. Hatfield, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended
32.1*	Pinnacle West	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	APS	Certification of Chief Executive Officer and Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	Pinnacle West APS	XBRL Instance Document
101.SCH	Pinnacle West APS	XBRL Taxonomy Extension Schema Document
101.CAL	Pinnacle West APS	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	Pinnacle West APS	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Pinnacle West APS	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	Pinnacle West APS	XBRL Taxonomy Definition Linkbase Document

*Furnished herewith as an Exhibit.

In addition, Pinnacle West and APS hereby incorporate the following Exhibits pursuant to Exchange Act Rule 12b-32 and Regulation §229.10(d) by reference to the filings set forth below:

Exhibit No.	Registrant(s)	Description	Previously Filed as Exhibit(1)	Date Filed
3.1	Pinnacle West	Pinnacle West Capital Corporation Bylaws, amended as of May 19, 2010	3.1 to Pinnacle West/APS June 30, 2010 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/3/2010
3.2	Pinnacle West	Articles of Incorporation, restated as of May 21, 2008	3.1 to Pinnacle West/APS June 30, 2008 Form 10-Q Report, File Nos. 1-8962 and 1-4473	8/7/2008
3.3	APS	Articles of Incorporation, restated as of May 25, 1988	4.2 to APS's Form S-3 Registration Nos. 33-33910 and 33-55248 by means of September 24, 1993 Form 8-K Report, File No. 1-4473	9/29/1993
3.4	APS	Amendment to the Articles of Incorporation of Arizona Public Service Company, amended May 16, 2012	3.1 to Pinnacle West/APS May 22, 2012 Form 8-K Report, File Nos. 1-8962 and 1-4473	5/22/2012
3.5	APS	Arizona Public Service Company Bylaws, amended as of December 16, 2008	3.4 to Pinnacle West/APS December 31, 2008 Form 10-K, File Nos. 1-8962 and 1-4473	2/20/2009

(1) Reports filed under File Nos. 1-4473 and 1-8962 were filed in the office of the Securities and Exchange Commission located in Washington, D.C.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PINNACLE WEST CAPITAL CORPORATION
(Registrant)

Dated: October 30, 2015

By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)

ARIZONA PUBLIC SERVICE COMPANY
(Registrant)

Dated: October 30, 2015

By: /s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Officer Duly Authorized to sign this Report)