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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2017

OR

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

For the transition period from to

Commission File Number	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 ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☒ No ☐

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

PINNACLE WEST CAPITAL CORPORATION	Yes ☒ No ☐
ARIZONA PUBLIC SERVICE COMPANY	Yes ☒ No ☐

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

PINNACLE WEST CAPITAL CORPORATION

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Emerging growth company ☐

ARIZONA PUBLIC SERVICE COMPANY

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Emerging growth company ☐

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

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

PINNACLE WEST CAPITAL CORPORATION	Yes ☐ No ☒
ARIZONA PUBLIC SERVICE COMPANY	Yes ☐ No ☒

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 April 25, 2017: 111,560,427
ARIZONA PUBLIC SERVICE COMPANY	Number of shares of common stock, $2.50 par value, outstanding as of April 25, 2017: 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.

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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 Combined Notes to 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," "project" 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, 2016 ("2016 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 reliability and customer service levels;
- variations in demand for electricity, including those due to weather, seasonality, the general economy, customer and sales growth (or decline), and the effects of energy conservation measures and distributed generation;
- power plant and transmission system performance and outages;
- competition in retail and wholesale power markets;
- regulatory and judicial decisions, developments and proceedings;
- new legislation, ballot initiatives and regulation, including those relating to environmental requirements, regulatory policy, nuclear plant operations and potential deregulation of retail electric markets;
- fuel and water supply availability;
- our ability to achieve timely and adequate rate recovery of our costs, including returns on and of debt and equity capital investment;
- our ability to meet renewable energy and energy efficiency mandates and recover related costs;
- risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainty;
- current and future economic conditions in Arizona, including in real estate markets;
- the development of new technologies which may affect electric sales or delivery;
- the cost of debt and equity capital and the ability to access capital markets when required;
- environmental, economic and other concerns surrounding coal-fired generation, including regulation of greenhouse gas emissions;
- volatile fuel and purchased power costs;
- the investment performance of the assets of our nuclear decommissioning trust, pension, and other postretirement benefit plans and the resulting impact on future funding requirements;
- the liquidity of wholesale power markets and the use of derivative contracts in our business;
- potential shortfalls in insurance coverage;
- new accounting requirements or new interpretations of existing requirements;
- generation, transmission and distribution facility and system conditions and operating costs;
- the ability to meet the anticipated future need for additional generation and associated transmission facilities in our region;
- the willingness or ability of our counterparties, power plant participants and power plant land owners to meet contractual or other obligations or extend the rights for continued power plant operations; and
- restrictions on dividends or other provisions in our credit agreements and Arizona Corporation Commission ("ACC") orders.

These and other factors are discussed in the Risk Factors described in Part I, Item 1A of our 2016 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.

PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

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

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
OPERATING REVENUES	$ 677,728	$ 677,167
OPERATING EXPENSES		
Fuel and purchased power	212,395	221,285
Operations and maintenance	219,976	243,195
Depreciation and amortization	127,627	119,476
Taxes other than income taxes	43,836	42,501
Other expenses	388	548
Total	604,222	627,005
OPERATING INCOME	73,506	50,162
OTHER INCOME (DEDUCTIONS)		
Allowance for equity funds used during construction	9,482	10,516
Other income (Note 8)	480	117
Other expense (Note 8)	(3,680)	(4,038)
Total	6,282	6,595
INTEREST EXPENSE		
Interest charges	51,864	50,744
Allowance for borrowed funds used during construction	(4,472)	(5,227)
Total	47,392	45,517
INCOME BEFORE INCOME TAXES	32,396	11,240
INCOME TAXES	4,211	1,914
NET INCOME	28,185	9,326
Less: Net income attributable to noncontrolling interests (Note 5)	4,873	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 23,312	$ 4,453
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — BASIC	111,728	111,296
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING — DILUTED	112,195	111,847
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING		
Net income attributable to common shareholders — basic	$ 0.21	$ 0.04
Net income attributable to common shareholders — diluted	$ 0.21	$ 0.04

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

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

	Three Months Ended March 31,	
	2017	2016
NET INCOME	$ 28,185	$ 9,326
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense of $674 and $546	(770)	(693)
Reclassification of net realized loss, net of tax expense of $356 and $200	1,207	1,141
Pension and other postretirement benefits activity, net of tax expense of $704 and $645	522	530
Total other comprehensive income	959	978
COMPREHENSIVE INCOME	29,144	10,304
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 24,271	$ 5,431

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

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

	March 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3,028	$ 8,881
Customer and other receivables	191,175	250,491
Accrued unbilled revenues	101,226	107,949
Allowance for doubtful accounts	(1,946)	(3,037)
Materials and supplies (at average cost)	252,598	253,979
Fossil fuel (at average cost)	30,656	28,608
Income tax receivable	9,531	3,751
Assets from risk management activities (Note 6)	4,222	19,694
Deferred fuel and purchased power regulatory asset (Note 3)	17,625	12,465
Other regulatory assets (Note 3)	138,316	94,410
Other current assets	48,565	45,028
Total current assets	794,996	822,219
INVESTMENTS AND OTHER ASSETS		
Assets from risk management activities (Note 6)	—	1
Nuclear decommissioning trust (Note 11)	805,048	779,586
Other assets	70,025	69,063
Total investments and other assets	875,073	848,650
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	17,436,720	17,341,888
Accumulated depreciation and amortization	(6,060,254)	(5,970,100)
Net	11,376,466	11,371,788
Construction work in progress	1,005,797	1,019,947
Palo Verde sale leaseback, net of accumulated depreciation (Note 5)	112,548	113,515
Intangible assets, net of accumulated amortization	251,208	90,022
Nuclear fuel, net of accumulated amortization	135,821	119,004
Total property, plant and equipment	12,881,840	12,714,276
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,321,473	1,313,428
Assets for other postretirement benefits (Note 4)	175,414	166,206
Other	144,029	139,474
Total deferred debits	1,640,916	1,619,108
TOTAL ASSETS	$ 16,192,825	$ 16,004,253

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

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

	March 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 250,197	$ 264,631
Accrued taxes	182,812	138,964
Accrued interest	48,576	52,835
Common dividends payable	—	72,926
Short-term borrowings (Note 2)	207,297	177,200
Current maturities of long-term debt (Note 2)	125,000	125,000
Customer deposits	76,149	82,520
Liabilities from risk management activities (Note 6)	41,932	25,836
Liabilities for asset retirements	8,627	9,135
Regulatory liabilities (Note 3)	101,208	99,899
Other current liabilities	152,015	244,000
Total current liabilities	1,193,813	1,292,946
LONG-TERM DEBT LESS CURRENT MATURITIES (Note 2)	4,273,890	4,021,785
DEFERRED CREDITS AND OTHER		
Deferred income taxes	2,955,441	2,945,232
Regulatory liabilities (Note 3)	948,293	948,916
Liabilities for asset retirements	623,394	615,340
Liabilities for pension benefits (Note 4)	469,746	509,310
Liabilities from risk management activities (Note 6)	63,213	47,238
Customer advances	92,113	88,672
Coal mine reclamation	224,516	221,910
Deferred investment tax credit	209,818	210,162
Unrecognized tax benefits	10,172	10,046
Other	162,476	156,784
Total deferred credits and other	5,759,182	5,753,610
COMMITMENTS AND CONTINGENCIES (SEE NOTE 7)		
EQUITY		
Common stock, no par value; authorized 150,000,000 shares, 111,587,048 and 111,392,053 issued at respective dates	2,595,042	2,596,030
Treasury stock at cost; 29,195 and 55,317 shares at respective dates	(2,270)	(4,133)
Total common stock	2,592,772	2,591,897
Retained earnings	2,278,867	2,255,547
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(38,548)	(39,070)
Derivative instruments	(4,315)	(4,752)
Total accumulated other comprehensive loss	(42,863)	(43,822)
Total shareholders’ equity	4,828,776	4,803,622
Noncontrolling interests (Note 5)	137,164	132,290
Total equity	4,965,940	4,935,912
TOTAL LIABILITIES AND EQUITY	$ 16,192,825	$ 16,004,253

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

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

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 28,185	$ 9,326
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	147,861	140,759
Deferred fuel and purchased power	(988)	1,007
Deferred fuel and purchased power amortization	(4,172)	2,388
Allowance for equity funds used during construction	(9,482)	(10,516)
Deferred income taxes	10,357	3,468
Deferred investment tax credit	(344)	(114)
Change in derivative instruments fair value	(101)	(111)
Stock compensation	9,997	16,687
Changes in current assets and liabilities:		
Customer and other receivables	47,007	47,282
Accrued unbilled revenues	6,723	6,445
Materials, supplies and fossil fuel	(667)	1,525
Income tax receivable	(5,780)	(4,048)
Other current assets	(17,353)	(8,131)
Accounts payable	22,147	(38,443)
Accrued taxes	43,706	43,289
Other current liabilities	(101,801)	(38,040)
Change in margin and collateral accounts — assets	(12)	681
Change in margin and collateral accounts — liabilities	—	410
Change in other long-term assets	(36,836)	(17,504)
Change in other long-term liabilities	1,604	(12,151)
Net cash flow provided by operating activities	140,051	144,209
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(348,824)	(378,500)
Contributions in aid of construction	5,975	12,464
Allowance for borrowed funds used during construction	(4,472)	(5,227)
Proceeds from nuclear decommissioning trust sales	151,126	141,809
Investment in nuclear decommissioning trust	(151,696)	(142,379)
Other	(793)	(472)
Net cash flow used for investing activities	(348,684)	(372,305)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	255,441	—
Short-term borrowing and payments — net	22,097	261,800
Short-term debt borrowings under revolving credit facility	8,000	—
Dividends paid on common stock	(71,177)	(67,611)
Common stock equity issuance - net of purchases	(11,580)	8,902
Other	(1)	1
Net cash flow provided by financing activities	202,780	203,092
NET DECREASE IN CASH AND CASH EQUIVALENTS	(5,853)	(25,004)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	8,881	39,488
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 3,028	$ 14,484

The accompanying notes are an integral part of the 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, 2016	111,095,402	$ 2,541,668	(115,030)	$ (5,806)	$ 2,092,803	$ (44,748)	$ 135,540	$ 4,719,457
Net income		—		—	4,453	—	4,873	9,326
Other comprehensive income		—		—	—	978	—	978
Issuance of common stock	52,122	5,397		—	—	—	—	5,397
Purchase of treasury stock (a)		—	(71,962)	(4,880)	—	—	—	(4,880)
Reissuance of treasury stock for stock-based compensation and other		—	179,056	10,144	(10)	—	1	10,135
Balance, March 31, 2016	111,147,524	$ 2,547,065	(7,936)	$ (542)	$ 2,097,246	$ (43,770)	$ 140,414	$ 4,740,413
Balance, January 1, 2017	111,392,053	$ 2,596,030	(55,317)	$ (4,133)	$ 2,255,547	$ (43,822)	$ 132,290	$ 4,935,912
Net income		—		—	23,312	—	4,873	28,185
Other comprehensive income		—		—	—	959	—	959
Issuance of common stock	194,995	(988)		—	—	—	—	(988)
Purchase of treasury stock (a)		—	(153,470)	(12,141)	—	—	—	(12,141)
Reissuance of treasury stock for stock-based compensation and other		—	179,592	14,004	8	—	1	14,013
Balance, March 31, 2017	111,587,048	$ 2,595,042	(29,195)	$ (2,270)	$ 2,278,867	$ (42,863)	$ 137,164	$ 4,965,940

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

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

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

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
ELECTRIC OPERATING REVENUES	$ 676,869	$ 676,632
OPERATING EXPENSES		
Fuel and purchased power	217,104	221,285
Operations and maintenance	212,218	238,711
Depreciation and amortization	127,208	119,446
Income taxes	11,373	5,850
Taxes other than income taxes	43,498	42,410
Total	611,401	627,702
OPERATING INCOME	65,468	48,930
OTHER INCOME (DEDUCTIONS)		
Income taxes	2,725	1,815
Allowance for equity funds used during construction	9,482	10,516
Other income (Note 8)	1,062	610
Other expense (Note 8)	(4,378)	(4,750)
Total	8,891	8,191
INTEREST EXPENSE		
Interest on long-term debt	47,491	46,819
Interest on short-term borrowings	2,128	2,077
Debt discount, premium and expense	1,177	1,139
Allowance for borrowed funds used during construction	(4,472)	(5,040)
Total	46,324	44,995
NET INCOME	28,035	12,126
Less: Net income attributable to noncontrolling interests (Note 5)	4,873	4,873
NET INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 23,162	$ 7,253

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

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

	Three Months Ended March 31,	
	2017	**2016**
NET INCOME	$ 28,035	$ 12,126
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Derivative instruments:		
Net unrealized loss, net of tax expense of $674 and $546	(770)	(693)
Reclassification of net realized loss, net of tax expense of $356 and $200	1,207	1,141
Pension and other postretirement benefits activity, net of tax expense of $590 and $558	611	611
Total other comprehensive income	1,048	1,059
COMPREHENSIVE INCOME	29,083	13,185
Less: Comprehensive income attributable to noncontrolling interests	4,873	4,873
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON SHAREHOLDER	$ 24,210	$ 8,312

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

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

	March 31, 2017	December 31, 2016
ASSETS		
PROPERTY, PLANT AND EQUIPMENT		
Plant in service and held for future use	$ 17,324,182	$ 17,228,787
Accumulated depreciation and amortization	(5,974,360)	(5,881,941)
Net	11,349,822	11,346,846
Construction work in progress	970,880	989,497
Palo Verde sale leaseback, net of accumulated depreciation (Note 5)	112,548	113,515
Intangible assets, net of accumulated amortization	251,045	89,868
Nuclear fuel, net of accumulated amortization	135,821	119,004
Total property, plant and equipment	12,820,116	12,658,730
INVESTMENTS AND OTHER ASSETS		
Nuclear decommissioning trust (Note 11)	805,048	779,586
Assets from risk management activities (Note 6)	—	1
Other assets	49,094	48,320
Total investments and other assets	854,142	827,907
CURRENT ASSETS		
Cash and cash equivalents	2,933	8,840
Customer and other receivables	190,898	262,611
Accrued unbilled revenues	101,226	107,949
Allowance for doubtful accounts	(1,946)	(3,037)
Materials and supplies (at average cost)	251,360	252,777
Fossil fuel (at average cost)	30,656	28,608
Income tax receivable	11,195	11,174
Assets from risk management activities (Note 6)	4,222	19,694
Deferred fuel and purchased power regulatory asset (Note 3)	17,625	12,465
Other regulatory assets (Note 3)	138,316	94,410
Other current assets	43,040	41,849
Total current assets	789,525	837,340
DEFERRED DEBITS		
Regulatory assets (Note 3)	1,321,473	1,313,428
Assets for other postretirement benefits (Note 4)	172,071	162,911
Other	130,327	130,859
Total deferred debits	1,623,871	1,607,198
TOTAL ASSETS	$ 16,087,654	$ 15,931,175

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

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

	March 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
CAPITALIZATION		
Common stock	$ 178,162	$ 178,162
Additional paid-in capital	2,421,696	2,421,696
Retained earnings	2,354,405	2,331,245
Accumulated other comprehensive loss:		
Pension and other postretirement benefits	(20,060)	(20,671)
Derivative instruments	(4,315)	(4,752)
Total accumulated other comprehensive loss	(24,375)	(25,423)
Total shareholder equity	4,929,888	4,905,680
Noncontrolling interests (Note 5)	137,164	132,290
Total equity	5,067,052	5,037,970
Long-term debt less current maturities (Note 2)	4,273,890	4,021,785
Total capitalization	9,340,942	9,059,755
CURRENT LIABILITIES		
Short-term borrowings (Note 2)	116,497	135,500
Accounts payable	245,774	259,161
Accrued taxes	178,393	130,576
Accrued interest	48,349	52,525
Common dividends payable	—	72,900
Customer deposits	76,149	82,520
Liabilities from risk management activities (Note 6)	41,932	25,836
Liabilities for asset retirements	8,182	8,703
Regulatory liabilities (Note 3)	101,208	99,899
Other current liabilities	149,486	226,417
Total current liabilities	965,970	1,094,037
DEFERRED CREDITS AND OTHER		
Deferred income taxes	3,008,075	2,999,295
Regulatory liabilities (Note 3)	948,293	948,916
Liabilities for asset retirements	615,230	607,234
Liabilities for pension benefits (Note 4)	449,222	488,253
Liabilities from risk management activities (Note 6)	63,213	47,238
Customer advances	92,113	88,672
Coal mine reclamation	209,126	206,645
Deferred investment tax credit	209,818	210,162
Unrecognized tax benefits	37,534	37,408
Other	148,118	143,560
Total deferred credits and other	5,780,742	5,777,383
COMMITMENTS AND CONTINGENCIES (SEE NOTE 7)		
TOTAL LIABILITIES AND EQUITY	$ 16,087,654	$ 15,931,175

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

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

	Three Months Ended March 31,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 28,035	$ 12,126
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization including nuclear fuel	147,443	140,729
Deferred fuel and purchased power	(988)	1,007
Deferred fuel and purchased power amortization	(4,172)	2,388
Allowance for equity funds used during construction	(9,482)	(10,516)
Deferred income taxes	8,899	3,394
Deferred investment tax credit	(344)	(114)
Change in derivative instruments fair value	(101)	(111)
Changes in current assets and liabilities:		
Customer and other receivables	60,782	47,575
Accrued unbilled revenues	6,723	6,445
Materials, supplies and fossil fuel	(631)	1,525
Other current assets	(15,007)	(8,172)
Accounts payable	22,847	(34,999)
Accrued taxes	47,817	38,784
Other current liabilities	(88,990)	(28,748)
Change in margin and collateral accounts — assets	(12)	681
Change in margin and collateral accounts — liabilities	—	410
Change in other long-term assets	(31,172)	(17,375)
Change in other long-term liabilities	1,888	(1,102)
Net cash flow provided by operating activities	173,535	153,927
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(343,139)	(369,861)
Contributions in aid of construction	5,975	12,464
Allowance for borrowed funds used during construction	(4,472)	(5,040)
Proceeds from nuclear decommissioning trust sales	151,126	141,809
Investment in nuclear decommissioning trust	(151,696)	(142,379)
Other	(774)	(472)
Net cash flow used for investing activities	(342,980)	(363,479)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of long-term debt	255,441	—
Short-term borrowings and payments — net	(19,003)	261,800
Dividends paid on common stock	(72,900)	(69,400)
Net cash flow provided by financing activities	163,538	192,400
NET DECREASE IN CASH AND CASH EQUIVALENTS	(5,907)	(17,152)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	8,840	22,056
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2,933	$ 4,904
Supplemental disclosure of cash flow information		
Cash paid during the period for:		
Income taxes, net of refunds	$ —	$ 8,772
Interest, net of amounts capitalized	$ 53,129	$ 55,580
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 78,977	$ 59,707

The accompanying notes are an integral part of the 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, 2016	71,264,947	$ 178,162	$ 2,379,696	$ 2,148,493	$ (27,097)	$ 135,540	$ 4,814,794
Net income		—	—	7,253	—	4,873	12,126
Other comprehensive income		—	—	—	1,059	—	1,059
Other		—	—	—	—	1	1
Balance, March 31, 2016	71,264,947	$ 178,162	$ 2,379,696	$ 2,155,746	$ (26,038)	$ 140,414	$ 4,827,980
Balance, January 1, 2017	71,264,947	$ 178,162	$ 2,421,696	$ 2,331,245	$ (25,423)	$ 132,290	$ 5,037,970
Net income		—	—	23,162	—	4,873	28,035
Other comprehensive income		—	—	—	1,048	—	1,048
Other		—	—	(2)	—	1	(1)
Balance, March 31, 2017	71,264,947	$ 178,162	$ 2,421,696	$ 2,354,405	$ (24,375)	$ 137,164	$ 5,067,052

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

COMBINED 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, 4C Acquisition, LLC ("4CA"), 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 5 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.

Amounts reported in our interim Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the respective annual periods, due to the effects of seasonal temperature variations on energy consumption, timing of maintenance on electric generating units, and other factors.

Our condensed consolidated financial statements reflect all adjustments (consisting only of normal recurring adjustments except as otherwise disclosed in the notes) that we believe are necessary for the fair presentation of our financial position, results of operations, and cash flows for the periods presented. Certain 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 2016 Form 10-K.

Certain line items are presented in more detail on the Condensed Consolidated Statements of Cash Flows than was presented in the prior years. The prior year amounts were reclassified to conform to the current year presentation. These reclassifications have no impact on net cash flows provided by operating activities. The following tables show the impacts of the reclassifications of the prior year's (previously reported) amounts (dollars in thousands):

Statements of Cash Flows for the Three Months Ended March 31, 2016	**As previously reported**	**Reclassifications to conform to current year presentation**	**Amount reported after reclassification to conform to current year presentation**
Cash Flows from Operating Activities			
Stock compensation	$ —	$ 16,687	$ 16,687
Change in other long-term liabilities	4,536	(16,687)	(12,151)

Supplemental Cash Flow Information

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

	Three Months Ended March 31,	
	2017	2016
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ (2)	$ 2,502
Interest, net of amounts capitalized	54,280	56,139
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 79,306	$ 59,707

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, to refinance indebtedness, and for other general corporate purposes.

Pinnacle West

At March 31, 2017, Pinnacle West had a $200 million facility that matures in May 2021. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At March 31, 2017, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $42.8 million of commercial paper borrowings.

At March 31, 2017, Pinnacle West had a $75 million 364-day unsecured revolving credit facility that matures in August 2017. Borrowings under the facility will bear interest at LIBOR plus 0.80% per annum. At March 31, 2017, Pinnacle West had $48 million outstanding under the facility.

APS

On March 21, 2017, APS issued an additional $250 million par amount of its outstanding 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance commercial paper borrowings and to replenish cash temporarily used to fund capital expenditures.

At March 31, 2017, APS had two revolving 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 2021. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At March 31, 2017, APS had $116.5 million of commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 7 for a discussion of APS's other 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 thousands):

	As of March 31, 2017		As of December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Pinnacle West	$ 125,000	$ 125,000	$ 125,000	$ 125,000
APS	4,273,890	4,558,285	4,021,785	4,300,789
Total	$ 4,398,890	$ 4,683,285	$ 4,146,785	$ 4,425,789

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 March 31, 2017, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.9 billion, and total capitalization was approximately $9.4 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.8 billion, assuming APS's total capitalization remains the same.

3. Regulatory Matters

Retail Rate Case Filing with the Arizona Corporation Commission

On June 1, 2016, APS filed an application with the ACC for an annual increase in retail base rates of $165.9 million. This amount excludes amounts that are currently collected on customer bills through adjustor mechanisms. The application requests that some of the balances in these adjustor accounts (aggregating to approximately $267.6 million as of December 31, 2015) be transferred into base rates through the ratemaking process. This transfer would not have an incremental effect on average customer bills. The average annual customer bill impact of APS's request is an increase of 5.74% (the average annual bill impact for a typical APS residential customer is 7.96%). The principal provisions of the application are described in detail in Note 3 of our 2016 Form 10-K.

On March 1, 2017, the ACC Staff filed with the ACC a settlement term sheet. The settlement term sheet was agreed to by a majority of the formal stakeholders in the rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations. The settlement term sheet was converted into a definitive settlement agreement (the "2017 Settlement Agreement"), was signed by the supporting parties and was filed with the ACC on March 27, 2017. The 2017 Settlement Agreement was submitted to the administrative law judge ("ALJ"), whose decision regarding whether the settlement should be approved will be reviewed by the ACC. Hearings on the proposed settlement began on April 24, 2017.

In its original filing, the Company requested that the rate increase become effective July 1, 2017. In July 2016, the ALJ set a procedural schedule for the rate proceeding, which supported completing the case within 12 months. On January 13, 2017, the ALJ issued a procedural order delaying hearings on the case for approximately one month to allow parties to prepare testimony on the distributed generation ("DG") rate design issues addressed in the value and cost of DG decision. In light of this delay in the start of the hearings on the settlement, we currently expect a moderate delay in the scheduling of a final ACC vote on the settlement beyond the originally-anticipated July 1, 2017 date.

On April 27, 2017, Commissioner Burns filed a motion requesting that the ALJ suspend and continue the rate case proceedings and facilitate an investigation to determine whether certain commissioners should be disqualified from further participation in the matter.

The 2017 Settlement Agreement provides for a net retail base rate increase of $94.6 million, excluding the transfer of adjustor balances, consisting of: (1) a non-fuel, non-depreciation, base rate increase of $87.2 million per year; (2) a base rate decrease of $53.6 million attributable to reduced fuel and purchased power costs; and (3) a base rate increase of $61 million due to changes in depreciation schedules.

Other key provisions of the agreement include the following:

- an agreement by APS not to file another general rate case application before June 1, 2019;
- an authorized return on common equity of 10.0%;
- a capital structure comprised of 44.2% debt and 55.8% common equity;
- a cost deferral order for potential future recovery in APS’s next general rate case for the construction and operating costs APS incurs for its Ocotillo modernization project;
- a cost deferral and procedure to allow APS to request rate adjustments prior to its next general rate case related to its share of the construction costs associated with installing selective catalytic reduction ("SCR") equipment at the Four Corners Power Plant ("Four Corners");
- a deferral for future recovery (or credit to customers) of the Arizona property tax expense above or below a specified test year level caused by changes to the applicable Arizona property tax rate;
- an expansion of the Power Supply Adjustor (“PSA”) to include certain environmental chemical costs and third-party battery storage costs;
- a new AZ Sun II program for utility-owned solar distributed generation with the purpose of expanding access to rooftop solar for low and moderate income Arizonans, recoverable through the Arizona Renewable Energy Standard and Tariff ("RES"), to be no less than $10 million per year, and not more than $15 million per year;
- an environmental improvement surcharge cumulative per kilowatt-hour (“kWh”) cap rate increase from $0.00016 to a new rate of $0.00050, which includes a balancing account;
- rate design changes, including:
    - a change in the on-peak time of use period from noon - 7 p.m. to 3 p.m. - 8 p.m. Monday through Friday, excluding holidays;
    - non-grandfathered distributed generation customers would be required to select a rate option that has time of use rates and either a new grid access charge or demand component;
    - a Resource Comparison Proxy (“RCP”) for exported energy of 12.9 cents per kWh in year one; and
- an agreement by APS not to pursue any new self-build generation (with certain exceptions) having an in-service date prior to January 1, 2022 (extended to December 31, 2027 for combined-cycle generating units), unless expressly authorized by the ACC.

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

APS cannot predict whether the 2017 Settlement Agreement will ultimately be approved by the ACC, or the exact timing of the ACC's consideration of the matter.

Prior Rate Case Filing

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

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 kWh; and (3) the transfer of cost recovery for certain renewable energy projects from the RES surcharge to base rates in an estimated amount of $36.8 million. Other key provisions of the 2012 Settlement Agreement are described in detail in Note 3 of our 2016 Form 10-K.

Cost Recovery Mechanisms

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

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

In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the "Solar Partner Program," placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The ACC expressly reserved that any determination of prudency of the residential rooftop solar program for rate making purposes would not be made until the project was fully in service, and APS has requested cost recovery for the project in its currently pending rate case. On September 30, 2016, APS presented its preliminary findings from the residential rooftop solar program in a filing with the ACC.

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

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. On April 7, 2017, APS filed an amended 2017 RES Implementation Plan and updated budget request which includes the revenue neutral transfer of specific revenue requirements in accordance with the 2017 Settlement Agreement. The ACC has not yet ruled on the Company's 2017 RES Implementation Plan.

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. The ACC noted that many of the provisions of the original rule may no longer be appropriate, and the underlying economic assumptions associated with the rule have changed dramatically. The proceeding will review such issues as the rapidly declining cost of solar generation, an increased interest in community solar projects, energy storage options, and the decline in fossil fuel generation due to stringent regulations of the United States Environmental Protection Agency ("EPA"). The proceeding will also examine the feasibility of increasing the standard to 30% of retail sales by 2030, in contrast to the current standard of 15% of retail sales by 2025. APS cannot predict the outcome of this proceeding.

Demand Side Management Adjustor Charge ("DSMAC"). 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. In March 2014, the ACC approved a Resource Savings Initiative that allows APS to count towards compliance with the ACC Electric Energy Efficiency Standards, savings from improvements to APS's transmission and delivery system, generation and facilities that have been approved through a DSM Plan.

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

On June 1, 2015, APS filed its 2016 DSM Plan requesting a budget of $68.9 million and minor modifications to its DSM portfolio to increase energy savings and cost effectiveness of the programs. On April 1, 2016, APS filed an amended 2016 DSM Plan that sought minor modifications to its existing DSM Plan and requested to continue the current DSMAC and current budget of $68.9 million. On July 12, 2016, the ACC approved APS's amended DSM Plan and directed APS to spend up to an additional $4 million on a new residential demand response or load management program that facilitates energy storage technology. On December 5, 2016, APS filed for ACC approval of a $4 million Residential Demand Response, Energy Storage and Load Management Program.

On June 1, 2016, the Company filed its 2017 DSM Implementation Plan, in which APS proposes programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017

DSM Implementation Plan is $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Implementation Plan that incorporated the proposed Residential Demand Response, Energy Storage and Load Management Program and the requested budget increased to $66.6 million. The ACC has not yet ruled on the Company's 2017 DSM Plan.

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. On July 12, 2016, the ACC ordered that ACC staff convene a workshop within 120 days to discuss a number of issues related to the Electric Energy Efficiency Standards, including the process of determining the cost effectiveness of DSM programs and the treatment of peak demand and capacity reductions, among others. ACC staff convened the workshop on November 29, 2016 and sought public comment on potential revisions to the Electric Energy Efficiency Standards. APS cannot predict the outcome of this proceeding.

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 2017 and 2016 (dollars in thousands):

	Three Months Ended March 31,	
	2017	**2016**
Beginning balance	$ 12,465	$ (9,688)
Deferred fuel and purchased power costs — current period	988	(1,007)
Amounts charged to customers	4,172	(2,388)
Ending balance	$ 17,625	$ (13,083)

The PSA rate for the PSA year beginning February 1, 2017 is $(0.001348) per kWh, as compared to $0.001678 per kWh for the prior year. This new rate is comprised of a forward component of $(0.001027) per kWh and a historical component of $(0.000321) per kWh.

Transmission Rates, Transmission Cost Adjustor ("TCA") 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, 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.

Effective June 1, 2016, APS's annual wholesale transmission rates for all users of its transmission system increased by approximately $24.9 million for the twelve-month period beginning June 1, 2016 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, 2016.

On January 31, 2017, APS made a filing to reduce the Post-Employment Benefits Other than Pension expense reflected in its FERC transmission formula rate calculation to recognize certain savings resulting from plan design changes to the other postretirement benefit plans. A transmission customer intervened and protested certain aspects of APS’s filing. FERC initiated a proceeding under Section 206 of the Federal Power Act to evaluate the justness and reasonableness of the revised formula rate filing APS proposed. At this time, APS is unable to predict the outcome of this proceeding.

APS's formula rate implementation protocols have been in effect since 2008. Recent FERC orders suggest that FERC is examining the structure of formula rate implementation protocols and may require companies to make changes to their protocols in the future. As a result, APS made an administrative filing to update its formula rate implementation protocols on March 3, 2017, which was accepted by FERC with an effective date of May 1, 2017.

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

APS files for a LFCR adjustment every January. APS filed its 2015 annual LFCR adjustment on January 15, 2015, requesting an LFCR adjustment of $38.5 million, which was approved on March 16, 2015, effective for the first billing cycle of March. APS filed its 2016 annual LFCR adjustment on January 15, 2016, requesting an LFCR adjustment of $46.4 million (a $7.9 million annual increase), to be effective for the first billing cycle of March 2016. The ACC approved the 2016 annual LFCR to be effective in May 2016. APS filed its 2017 LFCR adjustment on January 13, 2017 requesting an LFCR adjustment of $63.7 million (a $17.3 million per year increase over 2016 levels), to be effective for the first billing cycle of March 2017. On April 5, 2017, the ACC approved the 2017 annual LFCR adjustment as filed, to be effective with the first billing cycle of April 2017. Because the LFCR mechanism has a balancing account that trues up any under or over recoveries, a one or two month delay in implementation does not have an adverse effect on APS.

Net Metering

In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, the ALJ issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended decision by the ALJ. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC’s action, effective following APS’s pending rate case, the current net metering tariff that governs payments for energy exported to the grid from rooftop solar systems will be replaced by a more formula-driven approach that will utilize inputs from historical wholesale solar power costs and eventually an avoided cost methodology.

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

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to the date new rates are effective based on APS' pending rate case will be grandfathered for a period of 20 years from the date of interconnection;

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

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

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future rate cases, and the policy determinations themselves may be subject to future change as are all ACC policies. The determination of the initial export energy price to be paid by APS will be made in APS’s currently pending rate case. APS cannot predict the outcome of this determination.

The ACC’s decision did not make any policy determinations as to any specific costs to be charged to DG solar system customers for their use of the grid. The determination of any such costs will be made in APS's future rate cases.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserts that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. Consistent with Arizona statute, TASC filed a Notice of Appeal in the Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. In accordance with the 2017 Settlement Agreement described above, in the event the ACC approves the 2017 Settlement Agreement, these appeals will be withdrawn by TASC. The ACC's decision is expected to remain in effect during any legal challenge.

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

In a recent appellate challenge to an ACC rate decision involving a water company, the Arizona Court of Appeals considered the question of how the ACC should determine the “fair value” of a utility’s property, as specified in the Arizona Constitution, in connection with authorizing the recovery of costs through rate adjustors outside of a rate case. The Court of Appeals reversed the ACC’s method of finding fair value in that case, and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. The ACC sought review by the Arizona Supreme Court of this decision, and APS filed a brief supporting the ACC’s petition to the Arizona Supreme Court for review of the Court of Appeals’ decision. On February 9, 2016, the Arizona Supreme Court granted review of the decision and on August 8, 2016, the Arizona Supreme Court vacated the Court of Appeals opinion and affirmed the ACC’s orders approving the water company’s SIB adjustor.

System Benefits Charge

The 2012 Settlement Agreement provided that once APS achieved full funding of its decommissioning obligation under the sale leaseback agreements covering Unit 2 of Palo Verde, APS was required to implement a reduced System Benefits charge effective January 1, 2016. Beginning on January 1, 2016, APS began implementing a reduced System Benefits charge. The impact on APS retail revenues from the new System Benefits charge is an overall reduction of approximately $14.6 million per year with a corresponding reduction in depreciation and amortization expense. This adjustment is subsumed within the 2017 Settlement Agreement.

Subpoena from Arizona Corporation Commissioner Robert Burns

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

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

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for APS to produce all information previously requested through the subpoenas. APS did not produce the information requested and instead objected to the subpoena. Also, as part of the docket a workshop was held on March 24, 2017. On March 10, 2017, Commissioner Burns filed suit against APS and PNW in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner Burns suit against APS and PNW. APS and Pinnacle West 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 $62 million as of March 31, 2017 and is being amortized in rates over a total of 10 years. On February 23, 2015, the Arizona School Boards Association and the Association of Business Officials filed a notice of appeal in Division 1 of the Arizona Court of Appeals of the ACC decision approving the rate adjustments. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed above. On August 8, 2016, the Arizona Supreme Court issued its opinion in the SIB matter, and the Arizona Court of Appeals has now ordered supplemental briefing on how that SIB decision should affect the challenge to the Four Corners rate adjustment. We cannot predict when or how this matter will be resolved.

As part of APS’s acquisition of SCE’s interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS’s request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed a request for rehearing with FERC. In its order denying recovery FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. APS cannot predict the outcome of either matter.

Cholla

On September 11, 2014, APS announced that it would close Unit 2 of the Cholla Power Plant ("Cholla") and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approves a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APS's plan to retire Unit 2, without expressing any view on the future recoverability of APS's remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. In early 2017, EPA approved a final rule incorporating APS's compromise proposal, which was published in the Federal Register on March 27, 2017. Parties have until May 26, 2017 (60 days from publication in the Federal Register) to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot predict whether such petitions will be filed or if they will be successful.

Previously, APS estimated Cholla Unit 2’s end of life to be 2033. APS is currently recovering a return on and of the net book value of the unit in base rates. The 2017 Settlement Agreement described above contemplates continued recovery of the net book value of the unit and the unit’s decommissioning and other retirement-related costs. APS believes it will be allowed recovery of the remaining net book value of Unit 2 ($114 million as of March 31, 2017), 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.

Navajo Plant

On February 13, 2017, the co-owners of the Navajo Generating Station (the "Navajo Plant") voted not to pursue continued operation of the plant beyond December 2019, the expiration of the current lease term, and to pursue a new lease or lease extension with the Navajo Nation that would allow decommissioning activities to begin after December 2019 instead of later this year. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and the U.S. Department of the Interior have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. We cannot predict whether any alternate solutions will be found that would be acceptable to all of the stakeholders and feasible to implement. APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant. APS will seek continued recovery in rates for the book value of its remaining investment in the plant ($106 million as of March 31, 2017) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material. While we believe such costs are probable of recovery, we cannot predict whether or to what degree APS would obtain such recovery.

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

Regulatory Assets and Liabilities

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

	Amortization Through	March 31, 2017		December 31, 2016	
		Current	Non-Current	Current	Non-Current
Pension	(a)	$ —	$ 699,817	$ —	$ 711,059
Retired power plant costs	2033	9,913	115,110	9,913	117,591
Income taxes — allowance for funds used during construction ("AFUDC") equity	2047	6,202	150,629	6,305	152,118
Deferred fuel and purchased power — mark-to-market (Note 6)	2020	30,203	59,428	—	42,963
Deferred fuel and purchased power (b) (e)	2018	17,625	—	12,465	—
Four Corners cost deferral	2024	6,689	55,221	6,689	56,894
Income taxes — investment tax credit basis adjustment	2046	2,120	54,265	2,120	54,356
Lost fixed cost recovery (b)	2018	70,762	—	61,307	—
Palo Verde VIEs (Note 5)	2046	—	18,930	—	18,775
Deferred compensation	2036	—	36,846	—	35,595
Deferred property taxes	(c)	—	79,447	—	73,200
Loss on reacquired debt	2038	1,637	16,533	1,637	16,942
Tax expense of Medicare subsidy	2024	1,503	10,458	1,513	10,589
Demand Side Management	2018	5,491	—	3,744	—
AG-1 deferral	2018	—	6,976	—	5,868
Mead-Phoenix transmission line CIAC	2050	332	10,625	332	10,708
Transmission cost adjustor (b)	2018	2,071	2,460	—	1,588
Coal reclamation	2026	418	4,728	418	5,182
Other	Various	975	—	432	—
Total regulatory assets (d)		$ 155,941	$ 1,321,473	$ 106,875	$ 1,313,428

(a) See Note 4 for further discussion.
(b) See "Cost Recovery Mechanisms" discussion above.
(c) Per the provision of the 2012 Settlement Agreement.
(d) There are no regulatory assets for which the ACC has allowed recovery of costs, but not allowed a return by exclusion from rate base. FERC rates are set using a formula rate as described in "Transmission Rates, Transmission Cost Adjustor and Other Transmission Matters."
(e) Subject to a carrying charge.

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

	Amortization Through	March 31, 2017		December 31, 2016	
		Current	Non-Current	Current	Non-Current
Asset retirement obligations	2057	$ —	$ 298,796	$ —	$ 279,976
Removal costs	(a)	37,194	211,348	29,899	223,145
Other postretirement benefits	(c)	32,662	115,950	32,662	123,913
Income taxes — deferred investment tax credit	2046	4,315	108,691	4,368	108,827
Income taxes — change in rates	2046	2,565	69,497	1,771	70,898
Spent nuclear fuel	2047	—	72,755	—	71,726
Renewable energy standard (b)	2018	22,367	—	26,809	—
Demand side management (b)	2019	—	19,921	—	20,472
Sundance maintenance	2030	—	15,690	—	15,287
Deferred gains on utility property	2019	2,062	8,439	2,063	8,895
Four Corners coal reclamation	2031	—	19,684	—	18,248
Other	Various	43	7,522	2,327	7,529
Total regulatory liabilities		$ 101,208	$ 948,293	$ 99,899	$ 948,916

(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) See Note 4.

4. Retirement Plans and Other Postretirement 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. Because of plan changes in September 2014, the Company is currently in the process of seeking IRS approval to move approximately $145 million of the other postretirement benefit trust assets into a new trust account to pay for active union employee medical costs. In December 2016, FERC approved a methodology for determining the amount of other postretirement benefit trust assets to transfer into a new trust account to pay for active union employee medical costs. While we do not expect to transfer any funds prior to 2018, as of March 31, 2017, such methodology would result in an amount of approximately $145 million being transferred to the new trust account.

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

	Pension Benefits		Other Benefits	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2017	2016	2017	2016
Service cost — benefits earned during the period	$ 13,760	$ 14,266	$ 4,358	$ 3,937
Interest cost on benefit obligation	32,701	32,945	7,565	7,341
Expected return on plan assets	(43,710)	(43,792)	(13,350)	(9,122)
Amortization of:				
Prior service cost (credit)	20	132	(9,461)	(9,471)
Net actuarial loss	12,489	9,731	1,454	946
Net periodic benefit cost	$ 15,260	$ 13,282	$ (9,434)	$ (6,369)
Portion of cost charged to expense	$ 7,568	$ 6,519	$ (4,678)	$ (3,126)

Contributions

We have made voluntary contributions of $60 million to our pension plan year-to-date in 2017. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2017-2019 period. We expect to make contributions of less than $1 million in total for the next three years to our other postretirement benefit plans.

5. 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. APS will retain 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 $23 million annually through 2023, and $16 million annually for the period 2024 through 2033. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

The leases' terms 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. Predominantly due to the lease terms, 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 expense, resulting in an increase in net income for the three months ended March 31, 2017 and 2016 of $5 million, entirely attributable to the noncontrolling interests. Income attributable to Pinnacle West shareholders is not impacted by the consolidation.

Our Condensed Consolidated Balance Sheets at March 31, 2017 and December 31, 2016 include the following amounts relating to the VIEs (dollars in thousands):

	March 31, 2017	December 31, 2016
Palo Verde sale leaseback property plant and equipment, net of accumulated depreciation	$ 112,548	$ 113,515
Equity — Noncontrolling interests	137,164	132,290

Assets of the VIEs are restricted and may only be used for payment to the noncontrolling interest holders. These assets are reported on our condensed consolidated financial statements.

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 NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to make specified payments to the VIEs' noncontrolling equity participants 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 were to occur during the lease periods, APS may be required to pay the noncontrolling equity participants approximately $291 million beginning in 2017, and up to $456 million over the lease terms.

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.

6. 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.

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 10 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.

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 March 31, 2017, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Quantity	
Power	1,123	GWh
Gas	226	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 months ended March 31, 2017 and 2016 (dollars in thousands):

		Three Months Ended March 31,	
Commodity Contracts	**Financial Statement Location**	**2017**	**2016**
Loss Recognized in OCI on Derivative Instruments (Effective Portion)	OCI — derivative instruments	$ (96)	$ (147)
Loss Reclassified from Accumulated OCI into Income (Effective Portion Realized) (a)	Fuel and purchased power (b)	(851)	(941)

(a) During the three months ended March 31, 2017 and 2016, we had no losses 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 $3 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.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the three months ended March 31, 2017 and 2016 (dollars in thousands):

		Three Months Ended March 31,	
Commodity Contracts	**Financial Statement Location**	**2017**	**2016**
Net Loss Recognized in Income	Operating revenues	$ (288)	$ (102)
Net Loss Recognized in Income	Fuel and purchased power (a)	(52,627)	(30,936)
Total		$ (52,915)	$ (31,038)

(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 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 March 31, 2017 and December 31, 2016, include gross liabilities of $1 million and $2 million, respectively, 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 March 31, 2017 and December 31, 2016. 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.

As of March 31, 2017: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 28,193	$ (23,983)	$ 4,210	$ 12	$ 4,222
Investments and other assets	1,654	(1,654)	—	—	—
Total assets	29,847	(25,637)	4,210	12	4,222
Current liabilities	(61,861)	23,983	(37,878)	(4,054)	(41,932)
Deferred credits and other	(64,867)	1,654	(63,213)	—	(63,213)
Total liabilities	(126,728)	25,637	(101,091)	(4,054)	(105,145)
Total	$ (96,881)	$ —	$ (96,881)	$ (4,042)	$ (100,923)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash 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 $4,054.

As of December 31, 2016: (dollars in thousands)	Gross Recognized Derivatives (a)	Amounts Offset (b)	Net Recognized Derivatives	Other (c)	Amount Reported on Balance Sheet
Current assets	$ 48,094	$ (28,400)	$ 19,694	$ —	$ 19,694
Investments and other assets	6,704	(6,703)	1	—	1
Total assets	54,798	(35,103)	19,695	—	19,695
Current liabilities	(50,182)	28,400	(21,782)	(4,054)	(25,836)
Deferred credits and other	(53,941)	6,703	(47,238)	—	(47,238)
Total liabilities	(104,123)	35,103	(69,020)	(4,054)	(73,074)
Total	$ (49,325)	$ —	$ (49,325)	$ (4,054)	$ (53,379)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) No cash collateral has been provided to counterparties, or received from counterparties, that is subject to offsetting.
(c) Represents cash collateral and cash 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 $4,054.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties and have risk management contracts with many counterparties. As of March 31, 2017, we have no counterparties with positive exposures of greater than 10% of risk management assets. Our risk management process assesses and monitors the financial exposure of all counterparties. 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 March 31, 2017 (dollars in thousands):

	March 31, 2017
Aggregate fair value of derivative instruments in a net liability position	$ 126,728
Cash collateral posted	—
Additional cash collateral in the event credit-risk-related contingent features were fully triggered (a)	63,646

(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 $130 million if our debt credit ratings were to fall below investment grade.

7. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the United States Department of Energy ("DOE") in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE’s breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS’s share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of reported net income. In addition, the settlement agreement, as amended, provides APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2019.

APS has submitted three claims pursuant to the terms of the August 18, 2014 settlement agreement, for three separate time periods during July 1, 2011 through June 30, 2016. The DOE has approved and paid $65.2 million for these claims (APS’s share is $19 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income.

Nuclear Insurance

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act ("Price-Anderson Act"), which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with the Price-Anderson Act, the Palo Verde participants are insured against public liability for a nuclear incident up to approximately $13.4 billion per occurrence. Palo Verde maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers ("ANI"). The remaining balance of approximately $13.0 billion of liability coverage is provided through a mandatory industry-wide retrospective premium program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, APS could be responsible for retrospective premiums. The maximum retrospective premium per reactor under the program for each nuclear liability incident is approximately $127.3 million, subject to a maximum annual premium of $19 million per incident. Based on APS’s ownership interest in the three Palo Verde units, APS’s maximum retrospective premium per incident for all three units is approximately $111.1 million, with a maximum annual retrospective premium of approximately $16.6 million.

The Palo Verde participants maintain insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.8 billion. APS has also secured accidental outage insurance for a sudden and unforeseen accidental outage of any of the three units. The property damage, decontamination, and accidental outage insurance are provided by Nuclear Electric Insurance Limited ("NEIL"). APS is subject to retrospective premium adjustments under all NEIL policies if NEIL’s losses in any policy year exceed accumulated funds. The maximum amount APS could incur under the current NEIL policies totals approximately $24 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 $64.8 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 the first quarter of 2017 our fuel and purchased power commitments decreased approximately $600 million primarily due to updated estimated renewable energy purchases. The majority of these changes relate to the years 2022 and thereafter.

Other than the items described above, there have been no material changes, as of March 31, 2017, outside the normal course of business in contractual obligations from the information provided in our 2016 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 ("RI/FS"). The OU3 working group parties have agreed to a schedule with EPA that calls for the submission of a revised draft RI/FS by November 2017. 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. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID contractors filed ancillary lawsuits for recovery of costs against APS and the other defendants. In addition, on March 15, 2017, the Arizona District Court granted partial summary judgment to RID for one element of RID's lawsuit against APS and the other defendants. The court's order is interlocutory and subject to a pending motion for reconsideration. We are unable to predict the outcome of these matters; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Environmental Matters

APS is subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of both conventional pollutants and greenhouse gases, water quality, wastewater discharges, solid waste, hazardous waste, and 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 and the Navajo Plant. EPA will require these plants to install pollution control equipment that constitutes best available retrofit technology ("BART") to lessen the impacts of emissions on visibility surrounding the plants. EPA recently approved a proposed rule for Regional Haze compliance at Cholla that does not involve the installation of new pollution controls and that will replace an earlier BART determination for this facility. See below for details of the recent Cholla rule approval.

Four Corners. Based on EPA's final standards, APS estimates that its 63% share of the cost of required controls for Four Corners Units 4 and 5 would be approximately $400 million. In addition, APS and El Paso Electric Company ("El Paso") entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. Navajo Transitional Energy Company, LLC ("NTEC") has the option to purchase the interest within a certain timeframe pursuant to an option granted to NTEC. In December 2015, NTEC notified APS of its intent to exercise the option. The cost of the pollution controls related to the 7% interest is approximately $45 million, which will be assumed by the ultimate owner of the 7% interest.

Navajo Plant. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's 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. On March 20, 2017, the Court denied this petition for review and upheld the legality of EPA's final BART rule for the Navajo Plant. See "Navajo Plant" in Note 3 for information regarding future plans for the Navajo Plant.

Cholla. APS believes that EPA's original 2012 final rule establishing controls constituting BART for Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million, 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. Pending certain regulatory approvals, APS would permanently close Cholla Unit 2 and cease burning coal at Units 1 and 3 by the mid-2020s. (See Note 3 for details related to the resulting regulatory asset.) APS made the proposal with the understanding that additional emission control equipment is unlikely to be required in the future because retiring and/or converting the units as contemplated in the proposal is more cost effective than, and will result in increased visibility improvement over, the current BART requirements for NOx imposed on the Cholla units under EPA's BART FIP. APS's proposal involves state and federal rulemaking processes. In light of these ongoing administrative proceedings, on February 19, 2015, APS, PacifiCorp (owner of Cholla Unit 4), and EPA jointly moved the court to sever and hold in abeyance those claims in the litigation pertaining to Cholla pending regulatory actions by the state and EPA. The court granted the parties' unopposed motion on February 20, 2015.

On October 16, 2015, ADEQ issued a revised operating permit for Cholla, which incorporates APS's proposal, and subsequently submitted a proposed revision to the SIP to the EPA, which would incorporate the new permit terms. On June 30, 2016, EPA issued a proposed rule approving a revision to the Arizona SIP that incorporates APS's compromise approach for compliance with the Regional Haze program. EPA signed the final rule approving the Agency's proposal on January 13, 2017. Under the terms of an executive memorandum issued on January 20, 2017, this final rule was held back from publication in the Federal Register pending review by incoming EPA leadership. On March 16, 2017, the new EPA Administrator re-signed the final rule, thereby allowing for publication in the Federal Register, which occurred on March 27, 2017. Parties have until May 26, 2017 (60 days from publication in the Federal Register) to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot predict whether such actions will be filed or if they will be successful.

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.

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.

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

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. APS is currently evaluating compliance alternatives for Cholla and estimates that its share of incremental costs to comply with the CCR rule for this plant is in the range of $5 million to $40 million based upon which compliance alternatives are ultimately selected. 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, the majority of which has already been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. By October 17, 2017, electric utility companies that own or operate CCR disposal units, such as APS, must collect sufficient groundwater sampling data to initiate a detection monitoring program. To the extent that certain threshold constituents are identified through this initial detection monitoring at levels above the CCR rule's standards, the rule requires the initiation of an assessment monitoring program by April 15, 2018. If this assessment monitoring program reveals concentrations of certain constituents above the CCR rule standards that trigger remedial obligations, a corrective measures evaluation must be completed by October 12, 2018. Depending upon the results of such groundwater monitoring and data evaluations at each of Cholla, Four Corners and the Navajo Plant, we may be required to take corrective actions, the costs of which we are unable to reasonably estimate at this time.

Pursuant to a June 24, 2016 order by the D.C. Circuit Court of Appeals in the litigation by industry- and environmental-groups challenging EPA's CCR regulations, within the next three years EPA is required to complete a rulemaking proceeding concerning whether or not boron must be included on the list of groundwater constituents that might trigger corrective action under EPA's CCR rules. EPA is not required to take final action approving the inclusion of boron, but EPA must propose and consider its inclusion. Should EPA take final action adding boron to the list of groundwater constituents that might trigger corrective action, any resulting corrective action measures may increase APS's costs of compliance with the CCR rule at our coal-fired generating facilities. At this time, though, APS cannot predict when EPA will commence its rulemaking concerning boron or the eventual results of those proceedings.

Clean Power Plan. On August 3, 2015, EPA finalized carbon pollution standards for electric generating units ("EGUs"). Shortly thereafter, a coalition of states, industry groups and electric utilities challenged the legality of these standards, including EPA's Clean Power Plan for existing EGUs, in the U.S. Court of Appeals for the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. On March 28, 2017, President Trump issued an Executive Order that, among other things, instructs EPA to reevaluate Agency regulations concerning carbon emissions from EGUs and take appropriate action to suspend, revise or rescind the August 2015 carbon pollution standards for EGUs, including the Clean Power Plan. Also on March 28, 2017, the U.S. Department of Justice, on behalf of EPA, filed a motion with the U.S. Court of Appeals for the D.C. Circuit to hold the ongoing litigation over the August 2015 pollution standards in abeyance pending EPA action in accordance with the Executive Order. At this time we cannot predict the outcome of EPA's review of the August 2015 carbon pollution standards and whether EPA will take action to suspend, rescind or revise these regulations. The carbon pollution standards for EGUs on state and tribal lands are described in detail in Note 10 of our 2016 Form 10-K.

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

Federal Agency Environmental Lawsuit Related to Four Corners

On April 20, 2016, several environmental groups filed a lawsuit against the Office of Surface Mining Reclamation and Enforcement ("OSM") and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA") in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016. Briefing on the merits of this litigation is expected to extend through May 2017. On September 15, 2016, NTEC, the company that owns the adjacent mine, filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. Because the court has placed a stay on all litigation deadlines pending its decision regarding NTEC's motion to dismiss, the schedule for briefing and the anticipated timeline for completion of this litigation will likely be extended. We cannot predict the outcome of this matter or its potential effect on Four Corners.

Financial Assurances

In the normal course of business, we obtain standby letters of credit and surety bonds from financial institutions and other third parties. These instruments guarantee our own future performance and provide third parties with financial and performance assurance in the event we do not perform. These instruments support certain debt arrangements, commodity contract collateral obligations, and other transactions. As of March 31, 2017, standby letters of credit totaled $35 million and will expire in 2017. As of March 31, 2017, surety bonds expiring through 2019 totaled $61 million. The underlying liabilities insured by these instruments are reflected on our balance sheets, where applicable. Therefore, no additional liability is reflected for the letters of credit and surety bonds themselves.

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

Pinnacle West has issued parental guarantees and has provided indemnification under certain surety bonds for APS which were not material at March 31, 2017. Effective July 6, 2016, Pinnacle West has issued two parental guarantees for 4CA relating to payment obligations arising from 4CA’s acquisition of El Paso’s 7% interest in Four Corners, and pursuant to the Four Corners participation agreement payment obligations arising from 4CA’s ownership interest in Four Corners.

8. Other Income and Other Expense

The following table provides detail of Pinnacle West's Consolidated other income and other expense for the three months ended March 31, 2017 and 2016 (dollars in thousands):

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Other income:		
Interest income	$ 477	$ 117
Miscellaneous	3	—
Total other income	$ 480	$ 117
Other expense:		
Non-operating costs	$ (1,959)	$ (2,049)
Investment losses — net	(301)	(518)
Miscellaneous	(1,420)	(1,471)
Total other expense	$ (3,680)	$ (4,038)

The following table provides detail of APS's other income and other expense for the three months ended March 31, 2017 and 2016 (dollars in thousands):

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Other income:		
Interest income	$ 338	$ 73
Gain on disposition of property	308	332
Miscellaneous	416	205
Total other income	$ 1,062	$ 610
Other expense:		
Non-operating costs (a)	$ (2,166)	$ (1,966)
Loss on disposition of property	(88)	(426)
Miscellaneous	(2,124)	(2,358)
Total other expense	$ (4,378)	$ (4,750)

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

9. Earnings Per Share

The following table presents the calculation of Pinnacle West’s basic and diluted earnings per share for the three months ended March 31, 2017 and 2016 (in thousands, except per share amounts):

	Three Months Ended March 31,	
	2017	**2016**
Net income attributable to common shareholders	$ 23,312	$ 4,453
Weighted average common shares outstanding — basic	111,728	111,296
Net effect of dilutive securities:		
Contingently issuable performance shares and restricted stock units	467	551
Weighted average common shares outstanding — diluted	112,195	111,847
Earnings per weighted-average common share outstanding		
Net income attributable to common shareholders — basic	$ 0.21	$ 0.04
Net income attributable to common shareholders — diluted	$ 0.21	$ 0.04

10. Fair Value Measurements

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

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

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

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.

Certain instruments have been valued using the concept of Net Asset Value (“NAV”), as a practical expedient. These instruments are typically structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. These instruments are similar to mutual funds; however, they are not traded on an exchange. Instruments valued using NAV, as a practical expedient, are included in our fair value disclosures however, in accordance with GAAP are not classified within the fair value hierarchy levels.

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust, plan assets held in our retirement and other benefit plans and coal reclamation trust investments. See Note 7 in the 2016 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.

Coal Reclamation Trust Investments

The coal reclamation trust holds cash equivalent investments in money market funds that are valued using quoted prices in active markets, and are reported within Level 1.

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.

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 using the funds' NAV as a practical expedient. The funds' NAV is primarily derived from the quoted active market prices of the underlying equity securities held by the funds. We may transact in these commingled funds on a semi-monthly basis at the NAV. The commingled funds are maintained by a bank and hold investments in accordance with the stated objective of tracking the performance of the S&P 500 Index. Because the commingled funds' shares are offered to a limited group of investors, they are not considered to be traded in an active market. As these instruments are valued using NAV, as a practical expedient, they have not been classified within the fair value hierarchy.

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

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

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee’s internal operating controls and valuation processes. See Note 11 for additional discussion about our nuclear decommissioning trust.

Fair Value Tables

The following table presents the fair value at March 31, 2017, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at March 31, 2017
Assets						
Coal reclamation trust - cash equivalents (b)	$ 14,801	$ —	$ —	$ —		$ 14,801
Risk management activities — derivative instruments:						
Commodity contracts	—	20,431	9,416	(25,625)	(c)	4,222
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	—	—	374,695	(d)	374,695
Fixed income securities:						
Cash and cash equivalent funds	—	—	—	336	(e)	336
U.S. Treasury	94,709	—	—	—		94,709
Corporate debt	—	115,329	—	—		115,329
Mortgage-backed securities	—	115,332	—	—		115,332
Municipal bonds	—	81,932	—	—		81,932
Other	—	22,715	—	—		22,715
Subtotal nuclear decommissioning trust	94,709	335,308	—	375,031		805,048
Total	$ 109,510	$ 355,739	$ 9,416	$ 349,406		$ 824,071
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (75,627)	$ (51,101)	$ 21,583	(c)	$ (105,145)

(a) Primarily consists of long-dated electricity contracts.
(b) Represents investments restricted for coal mine reclamation funding related to Four Corners. These assets are included in the Other Assets line item, reported under the Investments and Other Assets section of our Condensed Consolidated Balance Sheets.
(c) Represents counterparty netting, margin and collateral. See Note 6.
(d) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(e) Represents nuclear decommissioning trust net pending securities sales and purchases.

The following table presents the fair value at December 31, 2016, of our assets and liabilities that are measured at fair value on a recurring basis (dollars in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other		Balance at December 31, 2016
Assets						
Coal reclamation trust - cash equivalents (b)	$ 14,521	$ —	$ —	$ —		$ 14,521
Risk management activities — derivative instruments:						
Commodity contracts	—	43,722	11,076	(35,103)	(c)	19,695
Nuclear decommissioning trust:						
U.S. commingled equity funds	—	—	—	353,261	(d)	353,261
Fixed income securities:						
Cash and cash equivalent funds	—	—	—	795	(e)	795
U.S. Treasury	95,441	—	—	—		95,441
Corporate debt	—	111,623	—	—		111,623
Mortgage-backed securities	—	115,337	—	—		115,337
Municipal bonds	—	80,997	—	—		80,997
Other	—	22,132	—	—		22,132
Subtotal nuclear decommissioning trust	95,441	330,089	—	354,056		779,586
Total	$ 109,962	$ 373,811	$ 11,076	$ 318,953		$ 813,802
Liabilities						
Risk management activities — derivative instruments:						
Commodity contracts	$ —	$ (45,641)	$ (58,482)	$ 31,049	(c)	$ (73,074)

(a) Primarily consists of long-dated electricity contracts.
(b) Represents investments restricted for coal mine reclamation funding related to Four Corners. These assets are included in the Other Assets line item, reported under the Investments and Other Assets section of our Condensed Consolidated Balance Sheets.
(c) Represents counterparty netting, margin and collateral. See Note 6.
(d) Valued using NAV as a practical expedient and, therefore, are not classified in the fair value hierarchy.
(e) 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. 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.

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 March 31, 2017 and December 31, 2016:

	March 31, 2017 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ 8,805	$ 30,313	Discounted cash flows	Electricity forward price (per MWh)	$16.65 - $36.64	$ 27.96
Natural Gas:						
Forward Contracts (a)	611	20,788	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.07 - $2.80	$ 2.42
Total	$ 9,416	$ 51,101				

(a) Includes swaps and physical and financial contracts.

	December 31, 2016 Fair Value (thousands)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ 10,648	$ 32,042	Discounted cash flows	Electricity forward price (per MWh)	$16.43 - $41.07	$ 29.86
Natural Gas:						
Forward Contracts (a)	428	26,440	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.32 - $3.60	$ 2.81
Total	$ 11,076	$ 58,482				

(a) Includes swaps and physical and financial contracts.

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 months ended March 31, 2017 and 2016 (dollars in thousands):

	Three Months Ended March 31,	
Commodity Contracts	**2017**	**2016**
Net derivative balance at beginning of period	$ (47,406)	$ (32,979)
Total net gains (losses) realized/unrealized:		
Included in OCI	—	—
Deferred as a regulatory asset or liability	(11,755)	(9,103)
Settlements	1,423	1,765
Transfers into Level 3 from Level 2	(38)	262
Transfers from Level 3 into Level 2	16,091	548
Net derivative balance at end of period	$ (41,685)	$ (39,507)
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.

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. See Note 2 for our long-term debt fair values.

11. 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 10 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 March 31, 2017 and December 31, 2016 (dollars in thousands):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
March 31, 2017			
Equity securities	$ 374,695	$ 207,708	$ —
Fixed income securities	430,016	10,022	(3,963)
Net receivables (a)	337	—	—
Total	$ 805,048	$ 217,730	$ (3,963)

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2016			
Equity securities	$ 353,261	$ 188,091	$ —
Fixed income securities	425,530	9,820	(4,962)
Net receivables (a)	795	—	—
Total	$ 779,586	$ 197,911	$ (4,962)

(a) Net receivables/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 thousands):

	Three Months Ended March 31,	
	2017	2016
Realized gains	$ 2,367	$ 2,438
Realized losses	(2,453)	(1,786)
Proceeds from the sale of securities (a)	151,126	141,809

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at March 31, 2017 is as follows (dollars in thousands):

	Fair Value
Less than one year	$ 12,143
1 year – 5 years	117,217
5 years – 10 years	114,131
Greater than 10 years	186,525
Total	$ 430,016

12. New Accounting Standards

Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers

In May 2014, a new revenue recognition accounting standard was issued. This standard provides a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance. Since the issuance of the new revenue standard, additional guidance was issued to clarify certain aspects of the new revenue standard, including principal versus agent considerations, identifying performance obligations, and other narrow scope improvements. The new revenue standard, and related amendments, will be effective for us on January 1, 2018. The standard may be adopted using a full retrospective application or a simplified transition method that allows entities to record a cumulative effect adjustment in retained earnings at the date of initial application.

We will adopt this standard on January 1, 2018, and expect to adopt the guidance using the modified retrospective transition approach. Our revenues are derived primarily from sales of electricity to our regulated retail customers, and based on our assessment we do not expect the adoption of this guidance will impact the timing of our revenue recognition relating to these customers. However, our evaluation is on-going and we continue to monitor certain industry related topics being addressed by the American Institute of Certified Public Accountants Revenue Recognition Working Group and the Financial Accounting Standards Board's Transition Resource Group. Conclusions reached by these groups could impact our application of the standard. Furthermore, the adoption of the new standard may impact our presentation of revenues and will impact our disclosures relating to revenue.

ASU 2016-01, Financial Instruments: Recognition and Measurement

In January 2016, a new accounting standard was issued relating to the recognition and measurement of financial instruments. The new guidance will require certain investments in equity securities to be measured at fair value with changes in fair value recognized in net income, and modifies the impairment assessment of certain equity securities. The new standard is effective for us on January 1, 2018. Certain aspects of the standard may require a cumulative effect adjustment and other aspects of the standard are required to be adopted prospectively. We plan on adopting this standard on January 1, 2018, and continue to evaluate the impacts the new guidance may have on our financial statements. As of March 31, 2017 we do not have significant equity investments that would be impacted by this standard.

ASU 2016-02, Leases

In February 2016, a new lease accounting standard was issued. This new standard supersedes the existing lease accounting model, and modifies both lessee and lessor accounting. The new standard will require a lessee to reflect most operating lease arrangements on the balance sheet by recording a right-of-use asset and a lease liability that will initially be measured at the present value of lease payments. Among other changes, the new standard also modifies the definition of a lease, and requires expanded lease disclosures. The new standard will be effective for us on January 1, 2019, with early application permitted. The standard must be adopted using a modified retrospective approach, with various optional practical expedients provided to facilitate transition. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

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

In June 2016, a new accounting standard was issued that amends the measurement of credit losses on certain financial instruments. The new standard will require entities to use a current expected credit loss model to measure impairment of certain investments in debt securities, trade accounts receivables, and other financial instruments. The new standard is effective for us on January 1, 2020 and must be adopted using a modified retrospective approach for certain aspects of the standard, and a prospective approach for other aspects of the standard. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

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

In January 2017, a new accounting standard was issued that clarifies the definition of a business. This standard is intended to assist entities with evaluating whether a transaction should be accounted for as an acquisition (or disposal) of assets or a business. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. The new standard is effective for us on January 1, 2018 using a prospective approach. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

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

In February 2017, a new accounting standard was issued intended to clarify the scope of accounting guidance pertaining to gains and losses from the derecognition of nonfinancial assets, and to add guidance for partial sales of nonfinancial assets. The new standard is effective for us on January 1, 2018. The guidance may be applied using either a retrospective or modified retrospective transition approach. We are currently evaluating this new accounting standard and the impacts it may have on our financial statements.

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

In March 2017, a new accounting standard was issued that modifies how plan sponsors present net periodic pension cost and net periodic postretirement benefit cost (net benefit costs). The presentation changes will require net benefit costs to be disaggregated on the income statement by the various components that comprise these costs. Specifically, only the service cost component will be eligible for presentation as an operating income item, and all other cost components will be presented as non-operating items. This presentation change must be applied retrospectively. Furthermore, the new standard only allows the service cost component to be eligible for capitalization. The change in capitalization requirements must be applied prospectively. The new guidance is effective for us on January 1, 2018. We are currently evaluating this new accounting standard and the impacts it will have on our financial statements. The adoption of this guidance will change our financial statement presentation of net benefit costs and amounts eligible for capitalization; however due to regulatory accounting we do not expect these changes will have a significant impact on our results of operations.

13. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in Pinnacle West's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three months ended March 31, 2017 and 2016 (dollars in thousands):

	Three Months Ended March 31,	
	2017	2016
Balance at beginning of period	$ (43,822)	$ (44,748)
Derivative Instruments		
OCI (loss) before reclassifications	(770)	(693)
Amounts reclassified from accumulated other comprehensive loss (a)	1,207	1,141
Net current period OCI (loss)	437	448
Pension and Other Postretirement Benefits		
Amounts reclassified from accumulated other comprehensive loss (b)	522	530
Net current period OCI (loss)	522	530
Balance at end of period	$ (42,863)	$ (43,770)

(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 6.
(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 4.

The following table shows the changes in APS's consolidated accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the three months ended March 31, 2017 and 2016 (dollars in thousands):

	Three Months Ended March 31,	
	2017	2016
Balance at beginning of period	$ (25,423)	$ (27,097)
Derivative Instruments		
OCI (loss) before reclassifications	(770)	(693)
Amounts reclassified from accumulated other comprehensive loss (a)	1,207	1,141
Net current period OCI (loss)	437	448
Pension and Other Postretirement Benefits		
Amounts reclassified from accumulated other comprehensive loss (b)	611	611
Net current period OCI (loss)	611	611
Balance at end of period	$ (24,375)	$ (26,038)

(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 6.
(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 Combined 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 2016 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. Palo Verde experienced strong performance during 2016, with the completion of two refueling outages. The fall refueling outage was completed in 28 days with the lowest collective radiation exposure dose for any pressurized water reactor outage.

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. (See Note 7 for information regarding challenges to the legality of the Clean Power Plan, a court-ordered stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations, and a recently-issued Executive Order requiring EPA to reevaluate the Clean Power Plan and consider whether to suspend, rescind or revise this regulation.)

EPA's nationwide CO_2 emissions reduction goal is 32% below 2005 emission levels. As finalized for the state of Arizona and the Navajo Nation, compliance with the Clean Power Plan could involve a shift in generation from coal to natural gas and renewable generation. If or until implementation plans for these jurisdictions are finalized, we are unable to determine the actual impacts to APS. APS continually analyzes its long-range capital management plans to assess the potential effects of these changes, understanding that any resulting regulation and legislation could impact the economic viability of certain plants, as well as the willingness or ability of power plant participants to continue participation in such plants.

Cholla

On September 11, 2014, APS announced that it would close its 260 MW Unit 2 at Cholla and cease burning coal at Units 1 and 3 by the mid-2020s if EPA approves a compromise proposal offered by APS to meet required air 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 7 for details of the proposal.) APS believes that the environmental benefits of this proposal are greater in the long-term than the benefits that would have resulted from adding emissions control equipment. APS closed Unit 2 on October 1, 2015.

On January 13, 2017, EPA approved a final rule incorporating APS's compromise proposal. Under the terms of an executive memorandum issued on January 20, 2017, this final rule was held back from publication in the Federal Register pending review by incoming EPA leadership. On March 16, 2017, the new EPA Administrator re-signed the final rule, thereby allowing for publication in the Federal Register, which occurred on March 27, 2017. Parties have until May 26, 2017 (60 days from publication in the Federal Register) to file a petition for review in the Ninth Circuit Court of Appeals. APS cannot predict whether such actions will be filed or if they will be successful.

Four Corners

Asset Purchase Agreement and Coal Supply Matters. On December 30, 2013, APS purchased SCE’s 48% interest in each of Units 4 and 5 of Four Corners. The final purchase price for the interest was approximately $182 million. In connection with APS’s prior retail rate case with the ACC, the ACC reserved the right to review the prudence of the Four Corners transaction for cost recovery purposes upon the closing of the transaction. On December 23, 2014, the ACC approved rate adjustments related to APS’s acquisition of SCE’s interest in Four Corners resulting in a revenue increase of $57.1 million on an annual basis. On February 23, 2015, the ACC decision approving the rate adjustments was appealed. APS has intervened and is actively participating in the proceeding. The Arizona Court of Appeals suspended the appeal pending the Arizona Supreme Court's decision in the SIB matter discussed below. On August 8, 2016, the Arizona Supreme Court issued its opinion in the SIB matter, and the Arizona Court of Appeals has now ordered supplemental briefing on how that SIB decision should affect the challenge to the Four Corners rate adjustment. We cannot predict when or how this matter will be resolved.

Concurrently with the closing of the SCE transaction described above, 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 NTEC, a company formed by the Navajo Nation to own the mine and develop other energy projects. BHP Billiton was retained by NTEC under contract as the mine manager and operator through 2016. Also occurring concurrently with the closing, the Four Corners’ co-owners executed the 2016 Coal Supply Agreement for the supply of coal to Four Corners from July 2016 through 2031. El Paso, a 7% owner in Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso’s 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Paso's reclamation and decommissioning obligations associated with the 7% interest.

NTEC has the option to purchase the 7% interest within a certain timeframe pursuant to an option granted to NTEC. On December 29, 2015, NTEC provided notice of its intent to exercise the option. The 2016 Coal Supply Agreement contains alternate pricing terms for the 7% shortfall obligations in the event NTEC does not purchase the interest.

Lease Extension. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process, and culminated in the issuance by DOI of a record of decision on July 17, 2015 justifying the agency action extending the life of the plant and the adjacent mine.

On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the ESA and NEPA in providing the federal approvals necessary to extend operations at the Four Corners Power Plant and the adjacent Navajo Mine past July 6, 2016. APS filed a motion to intervene in the proceedings, which was granted on August 3, 2016. Briefing on the merits of this litigation is expected to extend through May 2017. On September 15, 2016, NTEC filed a motion to intervene for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. Because the court has placed a stay on all litigation deadlines pending its decision regarding NTEC's motion to dismiss, the schedule for briefing and the anticipated timeline for completion of this litigation will likely be extended. We cannot predict the outcome of this matter or its potential effect on Four Corners.

Navajo Plant

On February 13, 2017, the co-owners of the Navajo Plant voted not to pursue continued operation of the plant beyond December 2019, the expiration of the current lease term, and to pursue a new lease or lease extension with the Navajo Nation that would allow decommissioning activities to begin after December 2019 instead of later this year. Various stakeholders including regulators, tribal representatives, the plant's coal supplier and the U.S. Department of the Interior have been meeting to determine if an alternate solution can be reached that would permit continued operation of the plant beyond 2019. We cannot predict whether any alternate solutions will be found that would be acceptable to all of the stakeholders and feasible to implement. APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant. APS will seek continued recovery in rates for the book value of its remaining investment in the plant (see Note 3 for additional details) plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material. While we believe such costs are probable of recovery, we cannot predict whether or to what degree APS would obtain such recovery.

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

Natural Gas. APS has six natural gas power plants located throughout Arizona, including Ocotillo. Ocotillo is a 330 MW 4-unit gas plant located in the metropolitan Phoenix area. In early 2014, APS announced a project to modernize the plant, which involves retiring two older 110 MW steam units, adding five 102 MW combustion turbines and maintaining two existing 55 MW combustion turbines. In total, this increases the capacity of the site by 290 MW, to 620 MW, with completion targeted by summer 2019. (See Note 3 for proposed rate recovery in our current retail rate case filing.) On September 9, 2016, Maricopa County issued a final permit decision that authorizes construction of the Ocotillo modernization project.

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 2019, along with other transmission costs for upgrades and replacements. APS is also working to establish and expand advanced grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better manage their energy usage, minimize system outage durations and frequency, enable customer choice for new customer sited technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain distribution functions.

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

Regulatory Matters

Rate Matters. APS needs timely recovery through rates of its capital and operating expenditures to maintain its financial health. APS's retail rates are regulated by the ACC and its wholesale electric rates (primarily for transmission) are regulated by FERC. See Note 3 for information on APS's FERC rates.

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

On March 1, 2017, the ACC Staff filed with the ACC a settlement term sheet. The settlement term sheet was agreed to by a majority of the formal stakeholders in the rate case, including the ACC Staff, the Residential Utility Consumer Office, limited income advocates and private rooftop solar organizations. The settlement term sheet was converted into the 2017 Settlement Agreement, was signed by the supporting parties and was filed with the ACC on March 27, 2017. (See Note 3 for details of the 2017 Settlement Agreement.)
The 2017 Settlement Agreement was submitted to the ALJ, whose decision regarding whether the settlement should be approved will be reviewed by the ACC. Hearings on the proposed settlement began on April 24, 2017.

In its original filing, the Company requested that the rate increase become effective July 1, 2017. In July 2016, the ALJ set a procedural schedule for the rate proceeding, which supported completing the case within 12 months. On January 13, 2017, the ALJ issued a procedural order delaying hearings on the case for approximately one month to allow parties to prepare testimony on the DG rate design issues addressed in the value and cost of DG decision. In light of this delay in the start of the hearings on the settlement, we currently expect a moderate delay in the scheduling of a final ACC vote on the settlement beyond the originally-anticipated July 1, 2017 date.

On April 27, 2017, Commissioner Burns filed a motion requesting that the ALJ suspend and continue the rate case proceedings and facilitate an investigation to determine whether certain commissioners should be disqualified from further participation in the matter.

APS cannot predict whether the 2017 Settlement Agreement will ultimately be approved by the ACC, or the exact timing of the ACC's consideration of the matter.

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

Renewable Energy. The ACC approved the RES in 2006. The renewable energy requirement is 7% of retail electric sales in 2017 and increases annually until it reaches 15% in 2025. In the 2009 Settlement Agreement, APS agreed to exceed the RES standards, committing to use APS's best efforts to obtain 1,700 GWh of new renewable resources to be in service by year-end 2015, in addition to its RES renewable resource commitments. APS met its settlement commitment and RES target for 2016. A component of the RES targets development of distributed energy systems.

On July 1, 2016, APS filed its 2017 RES Implementation Plan and proposed a budget of approximately $150 million. APS's budget request included additional funding to process the high volume of residential rooftop solar interconnection requests and also requested a permanent waiver of the residential distributed energy requirement for 2017 contained in the RES rules. On April 7, 2017, APS filed an amended 2017 RES Implementation Plan and updated budget request which includes the revenue neutral transfer of specific revenue requirements in accordance with the 2017 Settlement Agreement. The ACC has not yet ruled on the Company's 2017 RES Implementation Plan.

In September 2016, the ACC initiated a proceeding which will examine the possible modernization and expansion of the RES. The ACC noted that many of the provisions of the original rule may no longer be appropriate, and the underlying economic assumptions associated with the rule have changed dramatically. The proceeding will review such issues as the rapidly declining cost of solar generation, an increased interest in community solar projects, energy storage options, and the decline in fossil fuel generation due to stringent EPA regulations. The proceeding will also examine the feasibility of increasing the standard to 30% of retail sales by 2030, in contrast to the current standard of 15% of retail sales by 2025. APS cannot predict the outcome of this proceeding. See Note 3 for more information on the RES.

The following table summarizes renewable energy sources in APS's renewable portfolio that are in operation and under development as of May 2, 2017.

	Net Capacity in Operation (MW)	**Net Capacity Planned / Under Development (MW)**
Total APS Owned: Solar (a)	239	—
Purchased Power Agreements:		
Solar	310	—
Wind	289	—
Geothermal	10	—
Biomass	14	—
Biogas	6	—
Total Purchased Power Agreements	629	—
Total Distributed Energy: Solar (b)	607	45 (c)
Total Renewable Portfolio	1,475	45

(a) Included in the 239 MW number is 170 MW of solar resources procured through the Company's 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 has developed owned solar resources through the ACC-approved AZ Sun Program. APS has invested approximately $675 million in its AZ Sun Program.

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, 2016, the Company filed its 2017 DSM Implementation Plan, in which APS proposes programs and measures that specifically focus on reducing peak demand, shifting load to off-peak periods and educating customers about strategies to manage their energy and demand. The requested budget in the 2017 DSM Implementation Plan is $62.6 million. On January 27, 2017, APS filed an updated and modified 2017 DSM Implementation Plan that incorporated the proposed $4 million Residential Demand Response, Energy Storage and Load Management Program that was filed with the ACC on December 5, 2016 and the requested budget for the 2017 DSM Plan increased to $66.6 million. The ACC has not yet ruled on the Company's 2017 DSM Plan. See Note 3 for more information on demand side management.

Net Metering. In 2015, the ACC voted to conduct a generic evidentiary hearing on the value and cost of distributed generation to gather information that will inform the ACC on net metering issues and cost of service studies in upcoming utility rate cases. A hearing was held in April 2016. On October 7, 2016, an ALJ issued a recommendation in the docket concerning the value and cost of DG solar installations. On December 20, 2016, the ACC completed its open meeting to consider the recommended decision by the ALJ. After making several amendments, the ACC approved the recommended decision by a 4-1 vote. As a result of the ACC's action, effective following APS's pending rate case, the current net metering tariff that governs payments for energy exported to the grid from rooftop solar systems will be replaced by a more formula-driven approach that will utilize inputs from historical wholesale solar power costs and eventually an avoided cost methodology.

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

In addition, the ACC made the following determinations:

- Customers who have interconnected a DG system or submitted an application for interconnection for DG systems prior to the date new rates are effective based on APS's pending rate case will be grandfathered for a period of 20 years from the date of interconnection;

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

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

This decision of the ACC addresses policy determinations only. The decision states that its principles will be applied in future rate cases, and the policy determinations themselves may be subject to future change as are all ACC policies. The determination of the initial export energy price to be paid by APS will be made in APS's currently pending rate case, which is scheduled for hearing by the ACC in April 2017. APS cannot predict the outcome of this determination.

The ACC's decision did not make any policy determinations as to any specific costs to be charged to DG solar system customers for their use of the grid. The determination of any such costs will be made in APS's future rate cases.

On January 23, 2017, The Alliance for Solar Choice ("TASC") sought rehearing of the ACC's decision regarding the value and cost of DG. TASC asserts that the ACC improperly ignored the Administrative Procedure Act, failed to give adequate notice regarding the scope of the proceedings, and relied on information that was not submitted as evidence, among other alleged defects. Consistent with Arizona statute, TASC filed a Notice of Appeal in the Court of Appeals and filed a Complaint and Statutory Appeal in the Maricopa County Superior Court on March 10, 2017. In accordance with the Settlement Agreement described above, in the event the ACC approves the Settlement Agreement, these appeals will be withdrawn by TASC. The ACC's decision is expected to remain in effect during any legal challenge.

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

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

On February 7, 2017, Commissioner Burns opened a new ACC docket and indicated that its purpose is to study and rectify problems with transparency and disclosure regarding financial contributions from regulated monopolies or other stakeholders who may appear before the ACC that may directly or indirectly benefit an ACC Commissioner, a candidate for ACC Commissioner, or key ACC staff. As part of this docket, Commissioner Burns set March 24, 2017 as a deadline for APS to produce all information previously requested through the subpoenas. APS did not produce the information requested and instead objected to the subpoena. Also, as part of the docket a workshop was held on March 24, 2017. On March 10, 2017, Commissioner Burns filed suit against APS and PNW in an effort to enforce his subpoenas. On March 30, 2017, APS filed a motion to dismiss Commissioner Burns suit against APS and PNW. APS and Pinnacle West cannot predict the outcome of this matter.

FERC Matter. As part of APS's acquisition of SCE's interest in Four Corners Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS established a regulatory asset of $12 million in 2015 in connection with the payment required under the terms of the Transmission Agreement. On July 1, 2016, FERC issued an order denying APS's request to recover the regulatory asset through its FERC-jurisdictional rates. APS and SCE completed the termination of the Transmission Agreement on July 6, 2016. APS made the required payment to SCE and wrote-off the $12 million regulatory asset and charged operating revenues to reflect the effects of this order in the second quarter of 2016. On July 29, 2016, APS filed for a rehearing with FERC. In its order denying recovery, FERC also referred to its enforcement division a question of whether the agreement between APS and SCE relating to the settlement of obligations under the Transmission Agreement was a jurisdictional contract that should have been filed with FERC. APS cannot predict the outcome of either 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.

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

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

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

Key Financial Drivers

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

Electric Operating Revenues. For the years 2014 through 2016, retail electric revenues comprised approximately 94% 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.

Actual and Projected Customer and Sales Growth. Retail customers in APS's service territory increased 1.4% for the three-month period ended March 31, 2017 compared with the prior-year period. For the three years 2014 through 2016, APS's customer growth averaged 1.3% per year. We currently project annual customer growth to be 1.5-2.5% for 2017 and to average in the range of 2.0-3.0% for 2017 through 2019 based on our assessment of modestly improving economic conditions in Arizona.

Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, decreased 3.3% for the three-month period ended March 31, 2017 compared with the prior-year period. Improving economic conditions and customer growth were more than offset by energy savings driven by customer conservation, energy efficiency, distributed renewable generation initiatives and one fewer day of sales due to the leap year in 2016. For the three years 2014 through 2016, APS experienced annual increases in retail electricity sales averaging 0.2%, adjusted to exclude the effects of weather variations. We currently project that annual retail electricity sales in kWh will increase in the range of 0-1.0% for 2017 and increase on average in the range of 0.5-1.5% during 2017 through 2019, including the effects of customer conservation and energy efficiency and distributed renewable generation initiatives, but excluding the effects of weather variations. A slower recovery of the Arizona economy or acceleration of the expected effects of customer conservation, energy efficiency or distributed renewable generation initiatives could further impact these estimates.

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

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

Fuel and Purchased Power Costs. Fuel and purchased power costs included on our Consolidated Statements of Income are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market 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.

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.

Property Taxes. Taxes other than income taxes consist primarily of property taxes, which are affected by the value of property in-service and under construction, assessment ratios, and tax rates. The average property tax rate in Arizona for APS, which owns essentially all of our property, was 11.2% of the assessed value for 2016, 11.0% for 2015 and 10.7% for 2014. 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.

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. The prospects for broad-based federal tax reform have increased due to the results of the 2016 elections. Any such reform may impact the Company's effective tax rate, cash taxes paid and other financial results such as earnings per share, gross revenues and cash flows. Given the number of unknown variables and the lack of detailed legislative reform language, we are unable to predict any impacts to the Company at this time.

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 electric service to Native Load customers) and related activities and includes electricity generation, transmission and distribution.

Operating Results — Three-month period ended March 31, 2017 compared with three-month period ended March 31, 2016.

Our consolidated net income attributable to common shareholders for the three months ended March 31, 2017 was $23 million, compared with consolidated net income attributable to common shareholders of $4 million for the prior-year period. The results reflect an increase of approximately $18 million for the regulated electricity segment primarily due to lower operations and maintenance expenses related to fossil generation and employee benefit costs, higher lost fixed costs recovery and the effects of weather, partially offset by lower retail sales due to changes in customer usage patterns and related pricing.

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

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Net Change
	(dollars in millions)		
Regulated Electricity Segment:			
Operating revenues less fuel and purchased power expenses	$ 460	$ 455	$ 5
Operations and maintenance	(217)	(243)	26
Depreciation and amortization	(127)	(119)	(8)
Taxes other than income taxes	(44)	(43)	(1)
All other income and expenses, net	7	8	(1)
Interest charges, net of allowance for borrowed funds used during construction	(47)	(46)	(1)
Income taxes	(4)	(2)	(2)
Less income related to noncontrolling interests (Note 5)	(5)	(5)	—
Regulated electricity segment income	23	5	18
All other	—	(1)	1
Net Income Attributable to Common Shareholders	$ 23	$ 4	$ 19

Operating revenues less fuel and purchased power expenses. Regulated electricity segment operating revenues less fuel and purchased power expenses were $5 million higher for the three months ended March 31, 2017 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)		
Lost fixed cost recovery	$ 8	$ —	$ 8
Effects of weather	9	3	6
Lower retail sales due to changes in customer usage patterns and related pricing	(13)	(6)	(7)
Changes in net fuel and purchased power costs, including off-system sales margins and related deferrals	(3)	(4)	1
Miscellaneous items, net	(1)	2	(3)
Total	$ —	$ (5)	$ 5

Operations and maintenance. Operations and maintenance expenses decreased $26 million for the three months ended March 31, 2017 compared with the prior-year period primarily because of:

- A decrease of $18 million in fossil generation costs due to less planned outage activity in the current year period;

- A decrease of $7 million for employee benefit costs primarily related to the adoption of new stock compensation guidance in the fourth quarter of 2016;

- A decrease of $4 million for transmission, distribution, and customer service costs primarily due to decreased maintenance costs, partially offset by costs related to implementation of new systems;

- An increase of $6 million for costs primarily related to information technology and other corporate support; and

- A decrease of $3 million related to miscellaneous other factors.

Depreciation and amortization. Depreciation and amortization expenses were $8 million higher for the three months ended March 31, 2017 compared with the prior-year period primarily related to increased plant in service.

Income taxes. Income taxes were $2 million higher for the three months ended March 31, 2017 compared with the prior-year period primarily due to the effects of higher pretax income in the current year period, partially offset by a lower effective tax rate in the current year period primarily due to the adoption of new stock compensation guidance in 2016. The new guidance requires all excess income tax benefits and deficiencies arising from share-based payments to be recognized in earnings in the period they occur, which may cause effective tax rate fluctuations in future quarters when stock compensation payouts occur.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Our primary sources of cash are dividends from APS and external debt and equity issuances. An ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the related ACC order, the common equity ratio is defined as total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At March 31, 2017, APS's common equity ratio, as defined, was 52%. Its total shareholder equity was approximately $4.9 billion, and total capitalization was approximately $9.4 billion. Under this order, APS would be prohibited from paying dividends if such payment would reduce its total shareholder equity below approximately $3.8 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.

Many of APS's current capital expenditure projects qualify for bonus depreciation. On December 18, 2015, President Obama signed into law the Consolidated Appropriations Act, 2016 (H.R. 2029), which contained an extension of bonus depreciation through 2019. Enactment of this legislation is expected to generate approximately $300-$350 million of cash tax benefits over the next three years, which is expected to be fully realized by APS and Pinnacle West during this time frame. The cash generated by the extension of bonus depreciation is an acceleration of the tax benefits that APS would have otherwise received over 20 years and reduces rate base for ratemaking purposes. At Pinnacle West Consolidated, the extension of bonus depreciation will, in turn, delay until 2019 full cash realization of approximately $98 million of currently unrealized Investment Tax Credits, which are recorded as a deferred tax asset on the Condensed Consolidated Balance Sheet as of March 31, 2017.

Summary of Cash Flows

The following tables present net cash provided by (used for) operating, investing and financing activities for the three months ended March 31, 2017 and 2016 (dollars in millions):

Pinnacle West Consolidated

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Net Change
Net cash flow provided by operating activities	$ 140	$ 144	$ (4)
Net cash flow used for investing activities	(349)	(372)	23
Net cash flow provided by financing activities	203	203	—
Net decrease in cash and cash equivalents	$ (6)	$ (25)	$ 19

Arizona Public Service Company

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Net Change
Net cash flow provided by operating activities	$ 174	$ 154	$ 20
Net cash flow used for investing activities	(343)	(363)	20
Net cash flow provided by (used for) financing activities	163	192	(29)
Net decrease in cash and cash equivalents	$ (6)	$ (17)	$ 11

Operating Cash Flows

Three-month period ended March 31, 2017 compared with three-month period ended March 31, 2016. Pinnacle West's consolidated net cash provided by operating activities was $140 million in 2017 and $144 million in 2016. APS's variance from Pinnacle West is primarily due to the decrease of intercompany receivables.

Retirement plans and other postretirement benefits. Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. The requirements of the Employee Retirement Income Security Act of 1974 ("ERISA") require us to contribute a minimum amount to the qualified plan. We contribute at least the minimum amount required under ERISA regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of plan assets and our pension benefit obligations. Under ERISA, the qualified pension plan was 116% funded as of January 1, 2016 and 115% as of January 1, 2017. Under GAAP, the qualified pension plan was 88% funded as of January 1, 2016 and January 1, 2017. See Note 4 for additional details. The assets in the plan are comprised of fixed-income, equity, real estate, and short-term investments. Future year contribution amounts are dependent on plan asset performance and plan actuarial assumptions. We have made voluntary contributions of $60 million to our pension plan year-to-date in 2017. The minimum required contributions for the pension plan are zero for the next three years. We expect to make voluntary contributions up to a total of $300 million during the 2017-2019 period. We expect to make contributions of less than $1 million in total for the next three years to our other postretirement benefit plans.

Investing Cash Flows

Three-month period ended March 31, 2017 compared with three-month period ended March 31, 2016. Pinnacle West's consolidated net cash used for investing activities was $349 million in 2017, compared to $372 million in 2016, a decrease of $23 million in net cash used primarily related to decreased 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,		
	2017	**2018**	**2019**
APS			
Generation:			
Nuclear Fuel	$ 70	$ 71	$ 65
Renewables	4	17	16
Environmental	197	100	41
New Gas Generation	237	119	8
Other Generation	153	210	152
Distribution	398	415	491
Transmission	207	136	152
Other (a)	71	71	84
Total APS	$ 1,337	$ 1,139	$ 1,009

(a) Primarily information systems and facilities projects.

Generation capital expenditures are comprised of various improvements to APS's existing fossil, renewable 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. We have not included estimated costs for Cholla's compliance with EPA's regional haze rule. (See Note 7 for details regarding the status of the final rule for Cholla.) We are monitoring the status of other environmental matters, which, depending on their final outcome, could require modification to our planned environmental expenditures.

On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Paso's 7% interest in each of Units 4 and 5 of Four Corners. On December 29, 2015, NTEC notified APS of its intent to exercise its option to purchase the 7% interest in July 2017. 4CA purchased the El Paso interest on July 6, 2016. The table above does not include capital expenditures related to 4CA's interest in Four Corners Units 4 and 5 of approximately $27 million in 2017, $15 million in 2018 and $6 million in 2019, which will be assumed by the ultimate owner of the 7% interest.

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

Three-month period ended March 31, 2017 compared with three-month period ended March 31, 2016. Pinnacle West's consolidated net cash provided by financing activities was $203 million in 2017 and in 2016. The net cash provided by financing activities include $255 million higher issuances of long-term debt through March 31, 2017 offset by $232 million net decrease in short-term borrowings and $20 million primarily related to Pinnacle West's common stock for certain stock awards.

Significant Financing Activities. On April 19, 2017, the Pinnacle West Board of Directors declared a dividend of $0.655 per share of common stock, payable on June 1, 2017 to shareholders of record on May 1, 2017.

On March 21, 2017, APS issued an additional $250 million par amount of its outstanding 4.35% unsecured senior notes that mature on November 15, 2045. The net proceeds from the sale were used to refinance commercial paper borrowings and to replenish cash temporarily used to fund capital expenditures.

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

At March 31, 2017, Pinnacle West had a $200 million facility that matures in May 2021. Pinnacle West has the option to increase the amount of the facility up to a maximum of $300 million upon the satisfaction of certain conditions and with the consent of the lenders. At March 31, 2017, Pinnacle West had no outstanding borrowings under its credit facility, no letters of credit outstanding and $42.8 million of commercial paper borrowings.

At March 31, 2017, PNW had a $75 million 364-day unsecured revolving credit facility that matures in August 2017. PNW will use this facility to fund or otherwise support obligations related to 4CA, and borrowings under the facility will bear interest at LIBOR plus 0.80% per annum. At March 31, 2017, Pinnacle West had $48 million outstanding under the facility.

At March 31, 2017, APS had two revolving credit facilities totaling $1 billion, including a $500 million credit facility that matures in September 2020 and the $500 million facility that matures in May 2021. APS may increase the amount of each facility up to a maximum of $700 million, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS's senior unsecured debt credit ratings. These facilities are available to support APS's $500 million commercial paper program, for bank borrowings or for issuances of letters of credit. At March 31, 2017, APS had $116.5 million of commercial paper outstanding and no outstanding borrowings or letters of credit under its revolving credit facilities.

See "Financial Assurances" in Note 7 for a discussion of APS's separate outstanding letters of credit and surety bonds.

Other Financing Matters. See Note 6 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 March 31, 2017, the ratio was approximately 49% for Pinnacle West and 48% 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 6 for further discussions of liquidity matters.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of April 25, 2017 are shown below. We are disclosing these credit ratings to enhance understanding of our cost of short-term and long-term capital and our ability to access the markets for liquidity and long-term debt. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS's securities and/or result in an increase in the cost of, or limit access to, capital. Such revisions may also result in substantial additional cash or other collateral requirements related to certain derivative instruments, insurance policies, natural gas transportation, fuel supply, and other energy-related contracts. At this time, we believe we have sufficient available liquidity resources to respond to a downward revision to our credit ratings.

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

Off-Balance Sheet Arrangements

See Note 5 for a discussion of the impacts on our financial statements of consolidating certain VIEs.

Contractual Obligations

During the first quarter of 2017 our fuel and purchased power commitments decreased approximately $600 million primarily due to updated estimated renewable energy purchases. The majority of these changes relate to the years 2022 and thereafter.

Other than the items described above, there have been no material changes, as of March 31, 2017, outside the normal course of business in contractual obligations from the information provided in our 2016 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 2016 Form 10-K. See "Critical Accounting Policies" in Item 7 of the 2016 Form 10-K for further details about our critical accounting policies.

OTHER ACCOUNTING MATTERS

We are currently evaluating the impacts of adopting the following new accounting standards:

- Revenue recognition guidance, and related amendments, effective for us on January 1, 2018
- Financial instrument recognition and measurement guidance effective for us on January 1, 2018
- Presentation of net periodic pension costs and net periodic postretirement benefit costs, effective for us on January 1, 2018
- Business combination guidance, clarifying the definition of a business, effective for us on January 1, 2018
- Clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets, effective for us on January 1, 2018
- Lease accounting guidance effective for us on January 1, 2019
- Measurement of credit losses on financial instruments effective for us on January 1, 2020

See Note 12 for additional information related to accounting matters.

MARKET AND CREDIT RISKS

Market Risks

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

Interest Rate and Equity Risk

We have exposure to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and the market value of fixed income securities held by our nuclear decommissioning trust fund (see Note 10 and Note 11) 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 three months ended March 31, 2017 and 2016 (dollars in millions):

	Three Months Ended March 31,	
	2017	**2016**
Mark-to-market of net positions at beginning of year	$ (49)	$ (154)
Decrease (Increase) in regulatory asset/liability	(49)	(14)
Recognized in OCI:		
Mark-to-market losses realized during the period	1	1
Change in valuation techniques	—	—
Mark-to-market of net positions at end of period	$ (97)	$ (167)

The table below shows the fair value of maturities of our derivative contracts (dollars in millions) at March 31, 2017 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 2016 Form 10-K and Note 10 for more discussion of our valuation methods.

Source of Fair Value	**2017**	**2018**	**2019**	**2020**	**Total fair value**
Observable prices provided by other external sources	$ (22)	$ (27)	$ (5)	$ (1)	$ (55)
Prices based on unobservable inputs	(5)	(12)	(21)	(4)	(42)
Total by maturity	$ (27)	$ (39)	$ (26)	$ (5)	$ (97)

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 March 31, 2017 and December 31, 2016 (dollars in millions):

	March 31, 2017 Gain (Loss)		December 31, 2016 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)	$ 2	$ (2)
Natural gas	42	(42)	46	(46)
Total	$ 44	$ (44)	$ 48	$ (48)

(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 6 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 March 31, 2017. 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 March 31, 2017. 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 March 31, 2017 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 2016 Form 10-K with regard to pending or threatened litigation and other disputes.

See Note 3 for ACC and FERC-related matters.

See Note 7 for information regarding environmental matters and Superfund-related matters.

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 2016 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 2016 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.

Item 5. OTHER INFORMATION

Nuclear Waste Texas Lawsuit

On March 22, 2017, the State of Texas ("Texas") filed a lawsuit in the United States Court of Appeals for the Fifth Circuit ("Fifth Circuit") seeking various forms of equitable relief to address the federal government's responsibility to accept, transport and dispose of spent nuclear fuel and high level waste generated incident to the operation of the nation's commercial nuclear power plants. Texas has asked the Fifth Circuit to declare that the federal government has violated the Nuclear Waste Policy Act in two ways: (i) by conducting consent-based siting activities instead of pursuing the licensing of the Yucca Mountain, Nevada, repository; and (ii) by holding the Yucca Mountain adjudicatory licensing hearing in abeyance. Texas asks the Fifth Circuit to find that the government has violated the Nuclear Waste Policy Act; direct that the government's consent-based siting to cease and the Yucca Mountain adjudicatory licensing process to resume; and, if the government fails to do so, order other extraordinary measures, including restitution and disgorgement of funds that are maintained in the Nuclear Waste Fund by the government for carrying out its obligations pursuant to the Nuclear Waste Policy Act. The Nuclear Energy Institute, acting on behalf of the nation's commercial nuclear plants owners and operators, has filed a request to intervene in the lawsuit.

Westinghouse Bankruptcy

On March 29, 2017, Westinghouse Electric Company LLC filed for protection under Chapter 11 of the U.S. Bankruptcy Code. Toshiba Corporation, Westinghouse's parent company, cited significant losses arising from construction of four new nuclear generating units in Georgia and South Carolina as the reason to seek bankruptcy court protection. Westinghouse provides maintenance and engineering services, and nuclear fuel fabrication services to Palo Verde. Westinghouse has made representations in its bankruptcy court filings stating that the maintenance and engineering services, and fuel fabrication services business lines are profitable and will not be significantly impacted by the bankruptcy filing. We are unable to predict the outcome of this proceeding; however, we do not expect the outcome to have a material impact on our financial position, results of operations or cash flows.

Item 6. EXHIBITS

(a) Exhibits

Exhibit No.	Registrant(s)	Description
10.1	Pinnacle West APS	Proposed Settlement Agreement dated March 27, 2017 by and among APS and certain parties to its retail rate case
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 February 22, 2017	3.1 to Pinnacle West/APS February 28, 2017 Form 8-K Report, File Nos. 1-8962 and 1-4473	2/28/2017
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: May 2, 2017

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: May 2, 2017

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

DOCKET NOS. E-01345A-16-0036 and E-01345A-16-0123

SETTLEMENT AGREEMENT

MARCH 27 2017

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SETTLEMENT AGREEMENT
ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A RATE INCREASE (DOCKET NO. E-01345-A-0036) AND
THE FUEL AND PURCHASED POWER PROCUREMENT AUDIT OF APS
(DOCKET NO. E-01345A-16-0123)

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to Arizona Public Service Company's ("APS" or "Company") application to increase its rates (Docket No. E-01345A-16-0036) and the fuel and purchased power procurement audit of APS (Docket No. E-1345A-16-0123). This Agreement is entered into by the following entities:

Arizona Corporation Commission - Utilities Division Staff
Arizona Public Service Company
Residential Utility Consumer Office
Arizona Utility Ratepayer Alliance
Federal Executive Agencies
Arizona Solar Deployment Alliance
Arizona Solar Energy Industries Association
Vote Solar
Solar Energy Industries Association
Arizona School Boards Association and the Arizona Association of School Business Officials
Arizonans for Electric Choice and Competition
Western Resource Advocates
Wal-Mart Stores, Inc. and Sam's West, Inc.
Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO
Freeport Minerals Corporation
Arizona Community Action Association
The Kroger Co.
Arizona Investment Council
Property Owners & Residents Association, Sun City West

Sun City Home Owners Association
REP America d/b/a ConservAmerica
Constellation New Energy, LLC
Direct Energy Business, LLC
Calpine Energy Solutions, LLC
Arizona Competitive Power Alliance
Energy Freedom Coalition of America
City of Coolidge
Granite Creek Farms, LLC
Granite Creek Power & Gas, LLC

These entities shall be referred to collectively as Signing Parties; a single entity shall be referred to individually as a Signing Party.

I. RECITALS

1.1 APS filed the rate application underlying ACC Docket No. E-01345A-16-0036 on June 1, 2016. On August 6, 2016, the administrative law judge granted a motion to consolidate the Fuel and Purchased Power Procurement Audits, ACC Docket No. E-01345A-16-0123, with APS's rate case. Collectively, these dockets may be referred to herein as the Docket.

1.2 Subsequently, the Commission approved applications to intervene filed by Richard Gayer; Patricia Ferre; Warren Woodward; Arizona Solar Deployment Alliance ("ASDA"); IO Data Centers, LLC ("IO"); Freeport Minerals Corporation (Freeport) and Arizonans for Electric Choice and Competition (collectively, "AECC"); Sun City Home Owners Association ("Sun City HOA"); Western Resource Advocates ("WRA"); Arizona Investment Council ("AIC"); Arizona Utility Ratepayer Alliance ("AURA"), Property Owners and Residents Association, Sun City West ("PORA"); Arizona Solar Energy Industries Association ("AriSEIA"); Arizona School Boards Association ("ASBA") and Arizona Association of School Business Officials ("AASBO") (collectively, "ASBA/AASBO"); Cynthia Zwick, Arizona Community Action Association ("ACAA"); Southwest Energy Efficiency Project ("SWEEP"); the Residential Utility Consumer Office ("RUCO"); Vote Solar; Electrical District Number Eight and McMullen Valley Water Conservation & Drainage District (collectively, "ED8/McMullen"); The Kroger Co. ("Kroger"); Tucson

Electric Power Company (“TEP”); Pima County; Solar Energy Industries Association (“SEIA”); the Energy Freedom Coalition of America (“EFCA”); Wal-Mart Stores, Inc. and Sam’s West, Inc. (collectively, “Wal-Mart”); Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO (collectively, “the IBEW Locals”); Noble Americas Energy Solutions LLC (“Noble Solutions”); the Arizona Competitive Power Alliance (“the Alliance”); Electrical District Number Six, Pinal County, Arizona (“ED 6”); Electrical District Number Seven of the County of Maricopa, State of Arizona (“ED “7); Aguila Irrigation District (“AID”); Tonopah Irrigation District (“TID”); Harquahala Valley Power District (“HVPD”); and Maricopa County Municipal Water Conservation District Number One (“MWD”) (collectively, Districts); SunRun; the Federal Executive Agencies (“FEA”); Constellation New Energy, Inc. (“CNE”); Direct Energy, Inc. (“Direct Energy”); AARP; the City of Coolidge (“Coolidge”); REP America d/b/a ConservAmerica (“ConservAmerica”); and Granite Creek Power & Gas and Granite Creek Farms LLC (collectively, “Granite Creek”). SunRun subsequently withdrew its intervention.

1.3 APS filed a notice of revenue requirement settlement discussions on December 29, 2016. Revenue requirement settlement discussions began on January 12, 2017; rate design settlement discussions began on February 6, 2017. The settlement discussions were open, transparent, and inclusive of all parties to this Docket who desired to participate. All parties to this Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate.

1.4 The terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, establish just and reasonable rates for APS customers; promote the reliability of the electric system, as well as the convenience, comfort and safety, and the preservation of health, of the employees and customers of APS consistent with the Commission’s obligations under Arizona law; resolve the issues arising from this Docket; and avoid unnecessary litigation expense and delay.

1.5 The Signing Parties believe that this Agreement balances APS’s rate increase with benefits for customers. The Signing Parties agree that some of the significant provisions of the Agreement include:

a. A \$87.25 million non-fuel, non-depreciation revenue requirement increase, or a reduction of \$58.96 million from APS's original application.

b. An average 4.54% bill impact for residential customers compared to an average 7.96% bill impact for residential customers in APS's original application.

c. A refund to customers through the Demand Side Management Adjustor Clause ("DSMAC"), of \$15 million in collected, but unspent DSMAC funds to mitigate the first year bill impacts.

d. A rate case stay out, in which APS agrees not to file a new general rate case filing prior to June 1, 2019;

e. A program to expand access to utility owned rooftop solar for low and moderate income Arizonans, Title I Schools, and rural governments;

f. Continuation of a buy-through rate for Industrial and large General Service customers;

g. Continuation of crisis bill assistance for low income customers;

h. More off-peak hours and holidays for time-differentiated rates;

i. A moratorium on new self-build generation until January 1, 2022 and through December 31, 2027 for construction of combined-cycle generating units;

j. An experimental pilot technology rate initially available for up to 10,000 customers;

k. New updated rate designs with rate options for all customers.

l. An educational plan and concerted outreach effort by APS on its various rate plans with transitional rates in place until May 1, 2018 to allow for customer education;

m. Additional discounts for Schools and Military Customers;

n. Resolution of Solar Distributed Generation ("DG") issues for the term of the Settlement Agreement;

o. Agreement by Signing Parties to withdraw any appeals of the Commission's Value of Solar Decisions (Docket Nos. 75859 and 75932).

p. Agreement by Signing Parties to refrain from pursuing actions in any forum that are inconsistent with the provisions of the Settlement Agreement.

1.6 The Signing Parties request that the Commission find that the rates, terms and conditions of this Agreement are just, fair and reasonable and in the public interest in accordance with Article 15, Sections 3 and 14 of the Arizona Constitution and Arizona Revised Statutes Section 40-250 along with any and all other necessary findings, and to approve the Agreement and order that it and the rates contained herein become effective on July 1, 2017.

TERMS AND CONDITIONS

II. RATE CASE STABILITY PROVISION

2.1. APS will not file its next general rate case before June 1, 2019. The test year end date for the base rate increase filing contemplated in this section shall be no earlier than December 31, 2018.

II. RATE INCREASE

3.1. APS shall receive a $87.25 million non-fuel, non-depreciation revenue requirement increase. When the reduction for base fuel of $53.63 million and the increase for depreciation of $61.00 million is taken into account, the result is a net base rate increase of $94.624 million, exclusive of the adjustor transfer described below in Paragraph 3.2.

3.2 APS also requested to transfer amounts collected in adjustor mechanisms to base rates, which is revenue neutral since the adjustor balances will be reduced with the transfer to base rates. After including the transferred adjustor mechanism amount of $267.95 million, the Company's total base rate revenue requirement is $362.58 million ("revenue requirement"). This amount is comprised of: (1) a non-fuel base rate increase of $148.250 million, which includes a return on and of plant that is in service as of December 31, 2016 ("Post-Test Year Plant"), twelve (12) months beyond the test year ending December 31, 2015 (the "2015 Test Year"); (2) a base fuel rate decrease of $53.63 million; and (3) the transfer from adjustor mechanisms of $267.95 million to base rates described in Paragraph VIII herein. When these amounts are netted together, this amounts to a net base rate increase of $94.624 million.

3.3 The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is $9,990,561,000. APS's total adjusted Test Year revenue is $2,888,903,000.

3.4 In future rate cases, APS will agree to impute net revenue growth for any revenue producing plant included in post-test year plant.

III. BILL IMPACT

4.1 When new rates become effective, customers will have on average a 3.28% bill impact.

a. Residential customers will have on average a 4.54% bill impact.
b. General Service customers will have on average a 1.93% bill impact.

4.2 To mitigate the first year bill impacts, APS will refund to customers through the DSMAC $15 million in collected, but unspent DSMAC funds.

V. COST OF CAPITAL

5.1 An original cost of capital structure comprised of 44.2% debt and 55.8% common equity shall be adopted for ratemaking purposes for this Docket.

5.2 A return on common equity of 10.0% and an embedded cost of debt of 5.13% shall be adopted for ratemaking purposes for this Docket.

5.3 The Signing Parties agree to a fair value rate of return of 5.59% for this Docket, which includes a 0.8% return on the fair value increment.

5.4 The provisions set forth herein regarding the quantification of fair value rate base, fair value rate of return, and the revenue requirement are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to other or future cases.

VI. DEPRECIATION/AMORTIZATION AND DECOMMISSIONING

6.1 APS will lower its proposed annual depreciation expense pro forma on APS's as filed SFR C-2 by $20 million per year, resulting in a $61 million increase in depreciation expense (inclusive of the Cholla 2 Regulatory Asset Amortization), by adjusting its proposed lives/net salvage rates for its distribution accounts and by accelerating the amortization of the present excess depreciation reserves for Palo Verde.

6.2 The annual depreciation expense for the Palo Verde Nuclear Generating Station will be decreased by $21 million.

6.3 The decrease in Palo Verde depreciation not needed to fund the reduction in revenue requirements described in Section 6.1 above ("Excess Amount") will be offset by a more rapid amortization of the Cholla 2 regulatory asset such that there will be no additional impact on APS's revenue requirement in this case.

6.4 Should the Cholla 2 regulatory asset become fully amortized prior to APS's next general rate case, the Excess Amount will be used to accelerate the recovery of APS's remaining investment in the Navajo Generating Station.

6.5 For purposes of settling this rate case, APS's depreciation rates will be deemed to use the straight-line method, vintage group procedure, and remaining life technique.

6.6 In APS's next rate case, APS will file a depreciation rate study that includes alternative calculations for cost of removal and dismantlement (negative net salvage) using the "FAS 143" discounted net present value method, computed using a discount rate to be agreed upon.

6.7 A copy of APS's agreed upon depreciation rates is attached as Appendix A.

6.8 APS's annual nuclear decommissioning expense proposal will be adopted. A copy of the decommissioning contribution schedule is attached as Appendix B.

6.9 Subject to the discussion herein of Cholla 2, the Company shall use its proposed amortization rates for regulatory assets and liabilities as well as for other intangibles.

VII. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

7.1 The base fuel rate shall be lowered from $0.032071 per kWh as set in the Decision No. 73183 to $0.030168 per kWh. This change shall take effect on the effective date of the new rates contained in this Agreement, in accordance with the Plan of Administration for the Power Supply Adjustor ("PSA") to be approved in this case.

7.2 APS shall be permitted to include chemical costs for lime, ammonia and sulfur that are incurred in the generation process in the PSA.

7.3 APS shall be permitted to include third-party storage expenses in the PSA provided that APS files for approval to include any third-party storage contract with the Commission 90 days before it becomes effective.

7.4 The September 30 Preliminary Annual PSA Rate filing and the December 31 Final Annual PSA Rate calculation filing will be consolidated into one annual reset filing that will occur annually on or before November 30. Unless the Commission otherwise acts on the APS calculation by February 1, the PSA rate proposed by APS will go into effect with the first billing cycle in February.

7.5 The PSA Plan of Administration shall be amended as necessary to reflect the terms of this Agreement and shall be approved concurrent with the approval of this Agreement. The revised PSA Plan of Administration is attached as Appendix C.

VIII. TRANSFER OF ITEMS FROM ADJUSTMENT MECHANISMS TO BASE RATES

8.1 The Signing Parties agree that certain revenue requirements collected through the Renewable Energy Adjustor Clause ("REAC"), DSMAC Lost Fixed Cost Recovery ("LFCR"), Transmission Cost Adjustor ("TCA"), Environmental Impact Surcharge ("EIS"), Four Corners Rate Rider ("FCRR"), and the System Benefits Charge ("SBC") adjustment mechanisms shall be transferred to base rates and those adjustor rates will be zeroed out or reduced, as proposed by APS herein.

8.2 Adjustor transfers agreed to herein shall include the portion of transmission revenue requirements that was collected in the test year for the TCA, the portion of the lost fixed costs that was collected in the test year for the LFCR; the portion of environmental compliance revenue requirements that was collected in the test year for the EIS; an increase in the portion of energy efficiency expense to be collected in base rates from the DSMAC; the revenue requirement of Arizona Sun related renewable generation, the Schools and Governments Program and the Community Power Project will be transferred from the REAC into base rates; the portion of APS's acquisition of Southern California Edison's share of Four Corners currently collected in the Four Corners Rate Rider; and the portion of the System Benefits reduction that went into effect January 1, 2016 to reflect Palo Verde Unit 2 having been fully funded in the nuclear decommissioning trust. The specific amounts in each adjustor to be transferred to base rates pursuant to this Section are identified in Appendix D. The amounts transferred will be calculated using Staff's revenue conversion factor.

8.3 On the effective date of the new rates contained in this Agreement, the REAC, DSMAC, LFCR, TCA, EIS, FCRR and SBC rates shall be reduced to reflect the removal of the amounts identified in Appendix D.

IX. RATE TREATMENT RELATED TO THE INSTALLATION OF SELECTIVE CATALYTIC REDUCTIONS AT FOUR CORNERS UNITS 4 AND 5

9.1 The parties agree that this Docket shall remain open for the sole purpose of allowing APS to file a request that its rates be adjusted no later than January 1, 2019 to reflect the proposed addition of Selective Catalytic Reduction ("SCR") equipment at Four Corners, as requested in APS's application in this Docket.

9.2 APS shall be authorized by the Commission to defer for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating and maintaining the Selective Catalytic Reduction environmental controls at the Four Corners Power Plant from the date such controls go into service until the inclusion of such costs into rates. Nothing in this paragraph shall be construed in any way to limit this Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. The interest component of the SCR deferral will be set at APS's embedded cost of debt established in this Agreement.

9.3 Any filing seeking a rate adjustment pursuant to Section 9.1 shall include the following schedules: (1) the most current APS balance sheet at the time of filing; (2) the most current APS income statement at the time of filing; (3) an earnings schedule that demonstrates that the operating income resulting from the rate adjustment does not result in a return on rate base in excess of that authorized by this Agreement in the period after the rate adjustment becomes effective; (4) a revenue requirement calculation, including the amortization of any deferred costs; (5) an adjusted rate base schedule; and (6) a typical bill analysis under present and filed rates. The Signing Parties agree to use good faith efforts to process this rate adjustment request such that any resulting rate adjustment becomes effective no later than January 1, 2019, pursuant to Section 9.1.

9.4 The Signing Parties shall not present any issues in the rate adjustment proceeding other than those specifically described in this Section.

9.5 Section 9 is agreed to without prejudice to any position taken by a Signing Party in any other pending proceeding, including ASBA/AASBO v. ACC, 1 CA-CC-15-0001.

X. COST DEFERRAL RELATED TO THE OCOTILLO MODERNIZATION PROJECT

10.1 APS will be authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating, and maintaining the Ocotillo Modernization Project ("OMP") and retiring the existing steam generation at Ocotillo. Nothing in this paragraph shall be construed in any way to limit the Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. The interest component of the Ocotillo deferral will be set at APS's embedded cost of debt established in this Agreement.

10.2 The entire OMP will be in service before the rate effective date of APS's next general rate case, and the entire OMP investment will be addressed and resolved in that proceeding.

10.3 This agreement does not address the prudence of the OMP, and a deferral of the OMP costs does not guarantee recovery of those costs. Consideration of OMP in APS's next general rate case does not create any precedent, guarantee, or certainty regarding the consideration or treatment of post-test year plant.

XI. COST DEFERRAL RELATED TO CHANGES IN ARIZONA PROPERTY TAX RATE

11.1 APS shall be allowed to defer for future recovery (or credit to customers) the Arizona property tax expense above or below the test year caused by changes to the applicable Arizona composite property tax rate.

11.2 The property tax deferral will not accrue interest during the deferral period, unless it is negative, in which case, it will accrue interest in favor of APS's customers at APS's short term debt rate.

11.3 Beginning with the effective date of the Commission decision resulting from APS's next general rate case, any final property tax rate deferral that has a positive balance will be recovered from customers over 10 years, with a return at APS's short term debt rate, also with a return on any unrefunded negative balance at the same short term debt rate.

11.4 The Signing Parties reserve the right to review APS's property tax deferrals in APS's next general rate case for reasonableness and prudence.

11.5 Prior to the next APS general rate case, APS will meet and confer with Staff, RUCO and other stakeholders regarding the appropriate ratemaking treatment for the two year lag on payment of property taxes for post-test year plant.

XII. COST OF SERVICE STUDY

12.1 APS agrees in its next rate case to make available to parties its cost of service study in an Excel spreadsheet with inputs linked to outputs so that parties can change the inputs as necessary to reflect their position in the case. APS will meet and confer with stakeholders prior to filing to discuss the cost of service format.

12.2 In its next general rate case, APS agrees to perform the Average and Excess methodology to allocate production demand costs to residential and general service classes and then reallocate production demand within the residential sub-classes based on 4CP. This does not preclude APS or other stakeholders from proposing alternative allocation methods.

XIII. NAVAJO GENERATING STATION

13.1 APS will address any potential impacts of the closure of the Navajo Generating Station prior to the filing of APS's next rate case in Docket No. E-00000C-17-0039. To the extent it deems appropriate, APS may request that a separate Docket specific to APS be opened to address any issues pertaining to APS's interest in the Navajo Generating Station.

II. ANNUAL WORKFORCE PLANNING REPORT

14.1 APS shall file a workforce planning report with the Commission containing the following information: (i) the identification of each of the specific challenges or issues APS faces regarding workforce planning; (ii) the specific action(s) APS is taking to address each challenge or issue; and (iii) an update of the progress APS has made toward resolving each challenge or issue. The workforce planning report shall be filed on an annual basis, in this Docket, on or before May 31st, until the conclusion of the next APS general rate case, and shall be limited to the following job classifications: Electrician-Journeyman, Lineman-Journeyman, Technician-E&I, and Operator-Power Plant (a/k/a Auxiliary Operators and Control Operators). At a minimum, the workforce planning report shall set forth: (i) the number of employees then currently holding these positions; (ii) the present mean and median ages of APS's workforce with respect to these job classifications; (iii) the share of retirement-eligible employees, both as a percentage and in absolute terms, in each of these job classifications; and (iv) the anticipated hiring level and attrition level for each of these job classifications.

14.2 The obligation contained in this Section XIV for APS to file a workforce planning report supersedes any prior workforce planning reporting requirement including the requirement in Decision No. 73183.

III. SELF-BUILD MORATORIUM

15.1 APS will not pursue any new self-build generation option having an in-service date prior to January 1, 2022 unless expressly authorized by the Commission. Such restriction shall extend to December 31, 2027 with regard to the construction of combined-cycle generating units.

15.2 This self-build moratorium does not include any of the following: (1) the OMP; (2) the acquisition of a generating unit or an interest in a generating unit from a non-affiliated merchant or utility generator; (3) the acquisition of generation needed for system reliability when under the circumstances the seeking of prior Commission approval is impossible or impractical; (4) distributed generation or storage of less than 50 MW per location; (5) microgrids irrespective of size; (6) renewable generation; or (7) uprates or repowering of existing APS-owned generation.

15.3 As part of any APS request for Commission authorization to self-build generation, APS will address:

a. The Company's specific unmet needs for additional long-term resources.

b. The Company's efforts to secure adequate and reasonably-priced long-term resources from the competitive wholesale market to meet these needs.

c. The reasons why APS believes those efforts have been unsuccessful, either in whole or in part.

d. The extent to which the request to self-build generation is consistent with any applicable Company resource plans and competitive resource acquisition rules.

e. The anticipated cost of the proposed self-build option in comparison with suitable alternatives available from the competitive market for the relevant analysis period.

15.4 Nothing in this section shall be construed as relieving APS of its obligation to prudently acquire generating resources, including, but not limited to, seeking the above authorization to self-build a generating resource or resources.

15.5 The issuance of any RFP or the conduct of any other competitive solicitation in the future shall not, in and of itself, preclude APS from negotiating bilateral agreements with non-affiliated parties.

IV. TAX EXPENSE ADJUSTOR MECHANISM

16.1 In the event that significant Federal income tax reform legislation is enacted and becomes effective prior to the conclusion of APS's next general rate case, and such legislation materially impacts the

Company's annual revenue requirements, APS will create a rate adjustment mechanism to enable the pass-through of income tax effects to customers.

16.2 This adjustor mechanism has the following elements:

a. The change in revenue requirements due to Federal tax reform will be measured as the change in:

i. The Federal Income Tax Rate (currently 35%) applied to the Company's Adjusted 2015 Test Year;

ii. The annual amortization of any resulting excess deferred income tax regulatory account compared to the Company's Adjusted 2015 Test Year, and;

iii. Permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted 2015 Test Year.

b. The Company will change retail rates through the Tax Expense Adjustor Mechanism (TEAM).

i. The rate will be computed on a prospective basis each year based on the jurisdictional retail income tax change as compared to the income tax expense used to set rates in this proceeding combined with the Company's projection of jurisdictional retail sales for the coming year. The rate will be filed on December 1st and will become effective with the first billing cycle in March of each year.

ii. The adjustment will be assessed to each customer as an equal per kWh charge.

iii. The adjustor mechanism will include a balancing account such that any under- or over-collected balance will be recovered or refunded in the following year.

iv. Each year's under- or over-collected balance will accrue interest at the Company's applicable cost of short-term debt.

16.3 The TEAM will terminate with the effective date of APS's next general rate case.

16.4 The Plan of Administration for the TEAM is attached as Appendix E.

V. RESIDENTIAL RATE DESIGN

17.1 R-XS: Rate Schedule "R-XS" is available to customers without distributed generation using 600 or less kWh per month on average. The Basic Service Charge for R-XS is $10 for the average billing month, calculated at a daily rate of $0.329.

17.2 R-Basic: Rate Schedule "R-Basic" is available to customers without distributed generation using more than 600 kWh but less than 1,000 kWh per month on average. The Basic Service Charge for R-Basic is $15.00 for the average billing month, calculated at a daily rate of $0.493.

17.3 R-Basic Large: Rate Schedule "R-Basic Large" is available to customers without distributed generation using 1,000 kWh per month or more on average. The Basic Service Charge for R-Basic Large is $20.00 for the average billing month, calculated at a daily rate of $0.658.

17.4 TOU-E: Rate Schedule "TOU-E" is available to all customers. The Basic Service Charge for "TOU-E" is $13 for the average billing month, calculated at a daily rate of $0.427. Winter Super Off-peak hours are from 10:00am - 3:00pm. Customers currently on a Time Advantage rate plan will transition to this rate unless they select to voluntarily move to another rate for which they are eligible. For DG customers, the average off-set rate shall be inclusive of the Grid Access Charge described in Section 18.1.

17.5 R-2: Rate Schedule "R-2" is a three-part rate available to all customers. The Basic Service Charge for R-2 is $13 for the average billing month; calculated at a daily rate of $0.427.

17.6 R-3: Rate Schedule R-3 is a three-part rate available to all customers. The Basic Service Charge for R-3 is $13 for the average billing month; calculated at a daily rate of $0.427. Customers currently on the Combined Advantage rate plan will transition to this rate unless they select to voluntarily move to another rate for which they are eligible.

17.7 R-Tech: An Optional R-Tech Pilot Rate Program shall be created that will initially serve up to 10,000 customers. It is a three-part rate that is available to residential customers when the following criteria are met: (1) two or more qualifying primary on-site technologies were purchased within 90 days of the customer enrolling in the rate; or (2) one qualifying primary on-site technology was purchased within 90 days of the customer enrolling in the rate and two or more qualifying secondary on-site technologies. Qualifying technologies are set forth in Rate Schedule R-Tech attached hereto as Appendix F. The Basic Service Charge for R-Tech is $15 for the average billing month, calculated at a daily rate of $0.493.

a. Once 6,000 customers have signed up to take service under this program, and if such threshold has been reached prior to the Company's next general rate case filing, the Company shall provide notice and promptly convene a meeting of the interested parties to this Docket to discuss the future of the Pilot Program. If each of the parties to that discussion agree on a new customer participation level for the R-Tech Pilot Program that shall apply until the Commission determines the disposition of the R-Tech Pilot Program during the Company’s next general rate case the Company shall file a notice in this Docket to that effect and the program shall continue to be offered up to the new agreed upon customer participation level.

b. However, if all parties cannot agree to a new customer participation level, then APS shall file a report on the R-Tech Pilot Program and request that the Commission determine whether to continue, expand, or terminate the program in the Docket within 90 days of the date that 7,000 customers have begun taking service under this program. The Commission will then promptly review the program and determine if it should continue, terminate, or be adjusted.

c. The Signatories have agreed to a rate design for the R-Tech Pilot Rate Program as set forth in Appendix F.

17.8 The on-peak period will be 3:00 pm – 8:00 pm weekdays for TOU-E, R-2, R-3, and R-Tech, excluding holidays specified in Appendix F.

17.9 Attached as Appendix G is the Residential and Commercial rate summary.

VI. RESIDENTIAL RATE DESIGN FOR DISTRIBUTED GENERATION CUSTOMERS

18.1 DG customers are eligible for four different rate schedules including all proposed TOU and Demand rates. DG customers that select TOU-E will be subject to a Grid Access Charge as reflected in Appendix F.

18.2 The self-consumption offset rate for TOU-E will be $0.105/kWh, which is inclusive of the Grid Access Charge, but exclusive of taxes and adjustors. This is an approximately $0.120/kWh offset rate after these adjustments. The offset rate is based on the load profile and production profile of APS customers with DG during the test year. Individual customer offset will vary based on individual usage patterns and DG system size, orientation, and production.

18.3 The Resource Comparison Proxy Rate (“RCP”) for exported energy established in Decision No. 75859, as amended by Decision No. 75932, will be $0.129/kWh in year one, which is inclusive of undifferentiated transmission, distribution, and loss components. This export rate was calculated using a 2015 base year with an adjustment to achieve the final export rate. Attached as Appendix H is the RCP Rate Rider, POA and EPR-6 Legacy Rate Rider.

18.4 This first year export rate is the product of settlement negotiations and does not create any precedent, imply any change to the structure of or detail in the Resource Comparison Proxy, or otherwise change any aspect of Decision No. 75859.

18.5 DG customers that file a completed interconnection application before the rate effective date adopted in the Decision in this case shall be grandfathered consistent with Section 18.6 for a period of twenty years, with the twenty year period beginning from the date the system is interconnected with APS.

18.6 As contemplated in Decision No. 75859, grandfathered DG customers will continue to take service under full retail rate net metering and will continue to take service on their current tariff schedule for the length of the grandfathering period, which for APS are rate schedules E-12, ET-1, ET-2, ECT-1, or ECT-2. In its next rate case, APS will propose that the rates on each of these legacy tariffs will be updated with an equal percent increase applied to every rate component equal to the residential average base rate increase approved. In addition, grandfathered DG customers currently served on E-3 or E-4 will continue on the current E-3 or E-4 Rate Riders for as long as they meet the eligibility criteria and/or discontinue participation in the program.

VII. RESIDENTIAL RATE AVAILABILITY

19.1 All customers may select R-Basic, R-Basic Large, TOU-E, R-2, R-3, R-Tech or R-XS if they qualify until May 1, 2018, except to the extent grandfathered under other sections of this Settlement Agreement. Distributed Generation customers will not be eligible for R-XS, R-Basic or R-Basic Large. After May 1, 2018, R-Basic Large will no longer be available to new customers or customers who are on another rate. New customers after May 1, 2018 may choose TOU-E, R-2, R-3 or if they qualify, R-XS or R-Tech. After 90 days, new customers may opt-out of their current rate and select R-Basic if they qualify. Customers transitioning to R-Basic must stay on that rate for at least 12 months.

VIII. COMMERCIAL AND INDUSTRIAL RATE DESIGN

20.1 APS's General Service XS non-demand rate is adopted and attached as Appendix G.

20.2 APS's Aggregation feature and Extra High Load Factor Rate are as proposed by the Company. Copies of these Schedules are attached as Appendix I.

20.3 Economic Development Service Schedule 9 is approved as modified by Staff and is attached as Appendix J.

20.4 There will be no change to the current net metering structure for non-residential solar customers until addressed in a future Value of Solar or other proceeding.

20.5 The Signing Parties agree that issues related to the non-ratchet rate design alternative for C&I remain unresolved by this Agreement, and the Signing Parties agree they may present their respective positions in the hearing scheduled in this proceeding.

20.6 The on-peak period will be 3:00 pm – 8:00 pm weekdays for XS through E32-L, but will remain unchanged for E-35.

IX. E-32L RATE DESIGN

21.1 APS agrees to redesign E-32 L in a revenue neutral manner to recover an additional amount of $1.36 per kW in the unbundled generation charges.

X. SCHOOLS DISCOUNT RATE RIDER

22.1 All public schools and public school districts will be eligible for a new rate rider. If they apply for service under this rate rider they receive a discount of $0.0024/kWh.

XI. AG-X

23.1 The capacity reserve charge applicable to AG-X customers will be equal to $5.5398 per kW-month (60% of current FERC demand charge of $9.233 per kW), applied to 100% of the customer's billing demand.

23.2 This charge and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.

23.3 AG-X customers must provide 1-year notice to return to APS's cost-of-service rates. At APS's option, customers seeking to return with less notice must pay market-based rates until the 1-year notice period is attained.

23.4 The Administrative Management Fee for the program will be increased to $1.80 per MWh.

23.5 A retail energy imbalance protocol specifically designed to measure how well an AG-X Generation Service Provider ("GSP") is matching its retail buy-through customer load on an hourly basis will replace the FERC energy imbalance protocol. Energy Imbalance will be determined based on each GSP's aggregated hourly customer load.

a. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT, which now reflects the terms of the CAISO imbalance charges.

b. Greater than 15% each hour or +/- 2 MW, whichever is greater, in addition to the charges in a.above, GSPs would pay a penalty of $3 per MWh.

c. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again in a subsequent month, within 12 months from the date of the notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of GSP termination, the customer will be required to secure a replacement GSP within 60 days.

23.6 The PSA mitigation will remain in place. However the mitigation is modified such that the resale of capacity and energy displaced by AG-X is established at a flat $1,250,000 per month of off-system sales margins and excluded from the PSA rather than using a pro-rata share of such margins.

23.7 AG-X will remain at 200 MW but the prior restrictions as to 100 MW from each of the E-32L and E-34/35 rate schedules is eliminated; however, 100 MW would be allocated to 20 MW single-site customers with load factors above 70% unless not fully subscribed during the solicitation process.

23.8 Line losses for scheduling AG-X load will be modified to reflect transmission voltage service when applicable.

23.9 The 10 MW minimum aggregation level will be retained. Current provisions on the size of single site loads eligible for aggregation also will remain in place.

23.10 There will be a new lottery if the service is oversubscribed – otherwise, first come, first served. After the initial re-lottery, if necessary, customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

23.11 The AG-1 deferral will be recovered over 5 years from all non-residential customer classes, except the street and area lighting customer classes. The amount will be allocated to each class based on adjusted Test Year kWh. APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, nor propose the collection of unmitigated costs resulting from AG-X, if any, before or in its next rate case. Attached as Appendix K is the AG-X rate schedule.

XII. MILITARY CUSTOMERS

24.1 The unbundled delivery charge for service at military-primary voltage under rates E-34 and E-35 will be reduced to a level that results in any applicable military customer getting a net impact bill increase equal to the average for all retail customers.

XIII. REVENUE SPREAD

25.1 For the revised revenue requirement, APS will keep the same revenue spread between Residential and General Service classes. However, within General Service, because GS extra small and small customers originally had a near zero net bill impact, the reduction will be spread to all other GS customers proportionally to the original revenue spread. Attached as Appendix L is the revenue spread/targets summary.

XIV. EFFECTIVE DATE OF RATE PLANS AND TRANSITION PLAN

26.1 The rate increase will go into effect on the effective date of the Commission's Decision in this case using transition rates which for purposes of this Agreement are defined as existing Residential and extra small General Service rate schedules with updated revenue requirements. Customers will have the opportunity to select any rate which they qualify for, and APS will provide them information on options that would minimize their bill. Customers that do not select a different rate will transition to the updated rate plan most like their existing rate on or before May 1, 2018. At least 90 days before transitioning customers who have not selected a rate, APS will provide a report to the ACC indicating the total number of customers who have not made a selection.

XV. FIVE MILLION DSMAC ALLOCATION

27.1 APS will make a one-time allocation of $5 million from over-collected DSMAC funds to DSM programs for education and to help customers manage new rates and rate options including services and tools available to customers to help them manage their utility costs. APS shall file an outreach and education plan and shall provide stakeholders with an opportunity for review and comment on the draft plan prior to completing its final plan.

XVI. AZ SUN II

28.1 APS will implement a new program for utility-owned solar distributed generation. The purpose of this program is to expand access to rooftop solar for low and moderate income Arizonans. For this program, distributed generation will be defined as photovoltaic solar generation connected to the distribution system. APS will use third-party solar contractors to install the solar systems. The third-party solar contractors will be competitively selected through an RFP process. APS will own all the generation, renewable energy credits and other attributes from this program.

28.2 All reasonable and prudent costs incurred by APS pursuant to this program will be recoverable through the Renewable Energy Adjustment Clause until the next rate case.

a. Expenses eligible for recovery through the Renewable Energy Adjustment Clause include all O&M expenses, property taxes, marketing and advertising expenses, and the capital carrying costs of any capital investment by APS through this program (depreciation expenses at rates established by the Commission, and return on both debt and equity at the pre-tax weighted average cost of capital).

b. APS may request that the capital costs of the solar systems installed under this program be included in rate base in its next rate case.

c. APS's expenses under this program may be reviewed for prudence in each annual REST docket. Further, if APS includes any of these solar systems in rate base in the next rate case, those systems will be subject to a prudence review in that case.

d. APS will propose a program not less than $10 million per year, and not more than $15 million per year, in direct capital costs for the program. At least 65% of annual program will be dedicated to residential installations as defined in subsection 28.4.b. At the end of nine months of each program year, any unspent funds dedicated to low income residential installations can be used for other eligible customers.

e. Relation to annual REST docket. The program is approved in this Docket, and APS does not need to seek further approval in the REST Docket for the program or the spending authorized herein. However, APS shall report the number of installations, capital costs, and expenses in each annual REST docket. Further, recovery of the expenses through the Renewable Energy Adjustment Clause will be reviewed in the annual REST dockets as described herein.

28.3 This program will be available throughout APS's service area, including in rural Arizona.

28.4 This program is limited to low and moderate income residential APS customers as defined below, as well as non-profits that serve low or moderate income APS residential customers, Title I schools, and rural government customers. Rural government is defined as any state, local or tribal government entity in or serving a rural municipality. Rural Municipality means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area. Metro Area means a city with a population of 750,000 or more and its contiguous and surrounding communities.

a. Moderate income is defined as a household earning less than 100% of the median Arizona household income. APS will verify the income of each program participant.

b. Low income is defined as a household with income at or below 200% of the federal poverty level. APS will verify the income of each program participant.

28.5 APS may include any multi-family housing (such as apartment buildings) in the program.

28.6 Each residential APS customer participating in the program, upon installation of the solar system, will receive a bill credit of $10-50 per month applied to their APS bill. APS will work with stakeholders to discuss and determine the reasonable level of bill credit dependent upon type of installation. All other terms and conditions of the customer's rate option will continue to apply.

28.7 This program is approved for a period of three years from and after the date APS files a notice of program commencement in this Docket. APS will file the notice no later than three months after the effective date of the Commission's decision in this Docket. APS agrees to not implement any additional utility-owned residential solar distribution generation programs prior to APS's next general rate case beyond AZ Sun II, as outlined above.

28.8 APS will file a report with the Commission on the status of the program every quarter during the term of the program. The reporting will list the number of installs in each eligible category until the next APS rate case.

XVII. LIMITED INCOME PROGRAMS

29.1 The E-3 Energy Support Program for limited income customers will be revised to provide eligible customers with a flat 25% bill discount.

29.2 The E-4 Medical Support Program for limited income customers who have life sustaining medical equipment will be revised to provide eligible customers with a flat 35% bill discount.

29.3 APS agrees to fund $1.25 million annually the crisis bill program to assist customers whose incomes are less than or equal to 200% of the Federal Poverty Income Guidelines.

XVIII. AMI OPT-OUT/SCHEDULE 1

30.1 The AMI Opt-Out program will be approved as proposed by APS except the fees will be changed to reflect an upfront fee of $50 to change out a standard meter for a non-standard meter and monthly fee of $5. See Service Schedule 1, attached as Appendix M.

30.2 Changes to Schedule 1 are attached in Appendix M.

XIX. SCHEDULE 3

31.1 APS will create a new classification in Schedule 3: “Rural Municipal Business Developments” which means a tract of land that has (1) been divided into contiguous lots, (2) is owned and developed by a Rural Municipality and, (3) where the Rural Municipality will be the lease-holder for future, permanent lessee applicants.

31.2 Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of an application for service by permanent lessee applicants.

31.3 The refund eligibility period will be seven years (Rather than 5 years that applies to other classifications).

31.4 Advance payment of one-half of the project costs is due before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the refundable period. Any unrefunded advance balance paid at the start of the project plus the balance of project costs due at the end of the refund period will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement. (Rather than full advance required before start of construction). Changes to Schedule 3 are attached as Appendix N.

XXXII. LOST FIXED COST RECOVERY MECHANISM

32.1 The LFCR opt-out rate option approved in Decision 73183 will be removed.

32.2 The adjustment will no longer be applied to customer’s bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand.

32.3 APS shall submit its LFCR compliance filings on February 15th of each year. New LFCR rates shall take effect, upon Commission approval, with the first billing cycle in May of each year. The LFCR Plan of Administration is attached as Appendix O.

XXXIII. MODIFICATION TO ENVIRONMENTAL IMPROVEMENT SURCHARGE

33.1 APS shall be permitted to increase the cumulative per kWh cap rate for the Environmental Improvement Surcharge (“EIS”) from the current $0.00016 to a new rate of $0.00050 and include a balancing account.

33.2 A copy of the revised EIS Plan of Administration is attached as Appendix P.

XXXIII.TRANSMISSION COST ADJUSTMENT MECHANISM

34.1 APS shall be permitted to add a balancing account to the TCA.

34.2 Consistent with the Commission’s directive in Decision No. 72430, the annual TCA adjustment will become effective June 1 of each year without the need for affirmative Commission approval, consistent with the process approved by the Commission in Decision No. 72430.

34.3 A copy of the proposed TCA Plan of Administration is attached as Appendix Q.

XXXV. CHALLENGES TO DECISION NOS. 75859 AND 75932

35.1 Upon final approval of the Settlement Agreement by way of a final non-appealable Commission Order that includes no material changes to the terms of the Settlement Agreement, all Signing Parties will promptly take all necessary actions to (i) withdraw any challenge to Decision Nos. 75859 and 75932 they have filed. and (ii) refrain from pursuing any legal challenge to Decision Nos. 75859 and 75932 in any forum.

35.2 Prior to the issuance of a non-appealable Commission Order in this rate case, the Signing Parties agree to work together to secure a stay of any and all appeals that will suspend the filing of all pleadings, motions, briefings, or other court documents, until after the Commission issues its final Order in this case.

XXXVI. POWER SUPPLY ADJUSTOR AUDIT

36.1 Staff will docket the final audit report of APS's Power Supply Adjustor ("PSA") and the Signing Parties agree that any issues relating to the PSA audit report will be addressed in the hearing on this matter.

XXXVII. COMPLIANCE MATTERS

37.1 Staff's Recommendation for elimination or waiver of certain compliance requirements will be adopted. A list of the items to be eliminated or waived is attached as Appendix R.

37.2 Within ten days after the Commission issues an order in this matter, APS shall file compliance schedules associated with this Docket for Staff review. Subject to Staff review, such compliance schedules will become effective on the effective date of the new rates contained in this Agreement.

XXXVIII. FORCE MAJEURE PROVISION

38.1 Nothing in this Agreement shall prevent APS from requesting a change to its base rates in the event of conditions or circumstances that constitute an emergency. For the purposes of this Agreement, the term "emergency" is limited to an extraordinary event that, in the Commission's judgment, requires base rate relief in order to protect the public interest. This provision is not intended to preclude any party, including any Signing Party to this Agreement, from opposing an application for rate relief filed by APS pursuant to this paragraph. Nothing in this provision is intended to limit the Commission's ability to change rates at any time pursuant to its lawful authority.

XXXIX. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

39.1 All currently filed testimony and exhibits shall be offered into the Commission's record as evidence.

39.2 The Signing Parties recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

39.3 This Agreement shall serve as a procedural device by which the Signing Parties will submit their proposed settlement of APS's pending rate case, Docket No. E-01345A-16-0036 consolidated with Docket No. E-01345A-16-0123, to the Commission.

39.4 The Signing Parties recognize that the Commission will independently consider and evaluate the terms of this Agreement. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Signing Parties shall abide by the terms as approved by the Commission.

39.5 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Signing Parties may withdraw from this Agreement, and such Signing Party(ies) may pursue without prejudice their respective remedies at law. For the purposes of this Agreement, whether a term is material shall be left to the discretion of the Signing Party choosing to withdraw from the Agreement. If a Signing Party withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Signing Parties, whether or not the party has withdrawn from the Agreement, except for Staff, shall support the application for rehearing by filing a document with the Commission that supports approval of and future adherence to the Agreement in its entirety. Staff shall not be obligated to file any document or take any position regarding the withdrawing Signing Party's application for rehearing.

XL. MISCELLANEOUS PROVISIONS

40.1 This case has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because this Agreement, as a whole, is consistent with with the broad public interest. The acceptance by any Signing Party of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

40.2 No Signing Party is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signing Party shall offer evidence of conduct or statements made in the course of negotiating this Agreement before this Commission, any other regulatory agency, or any court, and no statement, communication or position of any party, their representatives, attorneys, or witnesses in the course of negotiations or in support of this Agreement shall be considered an admission or support for any position taken in any other forum or action.

40.3 Neither this Agreement nor any of the positions taken in this Agreement by any of the Signing Parties may be referred to, cited, or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except to secure approval of this Agreement and enforce its terms.

40.4 To the extent any provision of this Agreement is inconsistent with any existing Commission order, rule, or regulation, this Agreement shall control.

40.5 Each of the terms of this Agreement is in consideration of all other terms of this Agreement. Accordingly, the terms are not severable.

40.6 The Signing Parties shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signing Parties shall support and defend this Agreement before the Commission. Subject to subsection 40.5, if the Commission adopts an order approving all material terms of the Agreement, the Signing Parties will support and defend the Commission’s order before any court or regulatory agency in which it may be at issue.

40.7 This Agreement may be executed in any number of counterparts and by each Signing Party on separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement may also be executed electronically or by facsimile.

Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 and E-01345A-16-0123

SIGNATURE PAGE

ARIZONA CORPORATION COMMISSION

By: /s/ Elijah Abinah
Name: Elijah Abinah
Title: Acting Director, Utilities Division
Date: March 24, 2017

Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 and E-01345A-16-0123

SIGNATURE PAGE

Arizona Public Service Company

By: /s/ Barbara Lockwood
Name: Barbara Lockwood
Title: Vice President, Regulation
Date: March 24, 2017

Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 and E-01345A-16-0123

SIGNATURE PAGE

Residential Utlity Consumer Office

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Arizona Utility Ratepayer Alliance

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Federal Executive Agencies

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Arizona Public Service Company
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AriSEIA

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Vote Solar

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Energy Freedom Coalition of America

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Arizona School Board Association and the Arizona Association of School Business Officials

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Western resource Advocates

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Wal-Mart Stores, Inc. and Sam's West, Inc.

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Lubin & Enoch, P.C.

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The Kroger Co.

By: /s/ Kurt Boehm
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Property Owners & Residents Association (PORA) Sun City West

By: /s/ Al Gervenack
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Constellation New Energy, LLC

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Direct Energy Business, LLC

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Calpine Energy Solutions, LLC

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City of Coolidge

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Title: City of Coolidge Attorney
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Granite Creek Farms LLC
Granite Creek Power & Gas LLC

By: /s/ Thomas E. Stewart
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Title: General Manager
Date: March 24, 2017

Appendix F

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

AVAILABILITY

This rate schedule is available to residential Customers with the following:

1. Two or more qualifying primary on-site technologies were purchased within 90 days of the customer enrolling in the rate; or
2. One qualifying primary on-site technology was purchased within 90 days of the customer enrolling in the rate and two or more qualifying secondary on-site technologies.

This is a pilot rate schedule. This means this rate is associated with a specific program approved by the Arizona Corporation Commission, and is available only to those customers eligible to participate in the program. The R-Tech pilot program will test the ability and desire of participating residential customers to reduce On-Peak energy and demand usage through multiple behind-the-meter technologies.

Qualifying technologies for the R-Tech pilot program are as follows:

1. Primary technologies:
   a. A rooftop solar photovoltaic system. The size of the system cannot be smaller than 2 kW-dc. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).
   b. A chemical storage system. The size of the system cannot be smaller than 4 kWh. There is no maximum limitation for this technology.
   c. An electric vehicle. There are no limitations for this technology.

2. Secondary technologies:
   a. A device with a variable speed motor (such as a variable speed pool pump or a variable speed Heating, Ventilating, and Air Conditioning (HVAC) system).
   b. A grid-interactive water heating system.
   c. A smart thermostat.
   d. An automated load controller.

This rate schedule is initially limited to a maximum of 10,000 residential customers as outlined in Decision No. xxxxx.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the amount of demand (kW) averaged in a one hour period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will also vary by season (summer or winter) and time of day (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	$0.493	per day

		Summer	Winter	
On-Peak Demand Charge		$20.25	$14.25	per kW
Off-Peak Demand Charge	First 5 kW	$0.00	$0.00	per kW
	All remaining kW	$6.50	$6.50	

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RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

On-Peak Energy Charge	$0.05750	$0.04750	per kWh
Off-Peak Energy Charge	$0.04750	$0.04750	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	$0.125	per day
Metering Charge	$0.215	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Demand Charge Components

		Summer	Winter	
On-Peak Generation Charge		$13.750	$7.750	per kW
Off-Peak Generation Charge	First 5 kW	$0.000	$0.000	per kW
	All remaining kW	$1.000	$1.000	per kW
On-Peak Delivery Charge		$6.500	$6.500	per kW
Off-Peak Delivery Charge	First 5 kW	$0.000	$0.000	per kW
	All remaining kW	$5.500	$5.500	

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge for all kWh	$0.00210	per kWh

	Summer	Winter	
Generation On-Peak kWh Charge	$0.04167	$0.03167	per kWh
Generation Off-Peak kWh Charge	$0.03167	$0.03167	per kWh

The kW used to determine the On-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one hour On-Peak period for the month.

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

The kW used to determine the Off-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one hour Off-Peak period during the weekday (Monday through Friday), excluding holidays that may fall on a weekday.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

RCP	Resource Comparison Proxy
EPR-2	Partial Requirements
EPR-6	Partial Requirements – Net Metering (Residential Non-Solar)
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. This pilot rate schedule requires the Customer to have a standard AMI meter in place.

2. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.

3. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

4. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.

5. Electric service is supplied at a single point of delivery and measured through a single meter.

6. Direct Access customers are not eligible for this rate schedule.

Please note Appendix F also includes R-XS, R-Basic, R-Basic Large, TOU-E, R-2, and R-3 Rate Schedules which will be filed later.

Appendix H

RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR NEW ON-SITE SOLAR DISTRIBUTED GENERATION RESOURCE COMPARISON PROXY EXPORT RATE

AVAILABILITY

This rate rider is available to partial requirements customers with qualified on-site solar generation, served under an applicable residential rate. This rate rider may not be used in conjunction with a grandfathered residential Legacy rate schedule or Legacy rate rider.

DESCRIPTION

A Customer with solar generation exports power to the grid from time to time when their generation exceeds the load in their home. The Company will meter this export power on an instantaneous basis and provide a monthly bill credit based on the purchase rate in this schedule.

The purchase rates will be determined as follows:

a. An RCP rate will be determined for each annual tranche of new DG Customers, effective July 1 each year without proration. The RCP rate may not be reduced by more than 10% each year.

b. Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before July 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

c. Each Customer's initial RCP rate will be applicable for 10 years from the time of their interconnection.

d. After each Customer's initial 10 year period the bill credit will be based on the purchase rate in effect at that time, and may change from year to year.

Further details are provided in the Resource Comparison Proxy Plan of Administration and Arizona Corporation Commission Decisions No. 75859 and xxxxx.

PURCHASE RATES

The Company will provide a bill credit for the exported energy based on the following purchase rates:

Tranche 2017	July 1, 2017 through June 30, 2018	$0.1290	per kWh
Tranche 2018	July 1, 2018 through June 30, 2019	TBD	per kWh

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; however, if the outstanding credits exceed $25, the Company will automatically issue a check to the Customer. Otherwise, the bill credits will carry forward to the following year.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. Electricity must be generated using solar photovoltaic panels;

2. The generator must be interconnected to the Company's distribution grid;

3. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;

4. The facility's nameplate capacity cannot be larger than the following electrical service limits:
   a. For 200 Amp service, a maximum of 15 kW-dc.
   b. For 400 Amp service, a maximum of 30 kW-dc.
   c. For 600 Amp service, a maximum of 45 kW-dc.
   d. For 800 Amp service and above, a maximum of 60 kW-dc; and

5. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

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RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR NEW ON-SITE SOLAR DISTRIBUTED GENERATION RESOURCE COMPARISON PROXY EXPORT RATE

SPECIAL CASES

1. Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the Customer will not be eligible for an initial 10-year lock in the purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

2. Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this rate rider, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.

3. Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have a standard Advanced Metering Infrastructure (AMI) meter installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms an conditions may be included in a Customer's interconnection agreement.

4. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

Resource Comparison Proxy
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Resource Comparison Proxy purchase rate (RCP) approved for Arizona Public Service Company (APS or Company) in Arizona Corporation Commission (Commission) Decision No. 75859 (January 3, 2017), as modified by Decision No. 75932 (January 13, 2017) and implemented in Decision No. xxxxx (xxx x, 2017). The RCP is the price at which the Company purchases Exported Energy from residential Customers with qualified on-site solar distributed generation facilities. This price is provided in Rate Rider RCP.

The RCP is a proxy for the avoided cost of providing electrical service that results when a distributed generator exports power to the grid. The RCP is calculated using: (i) a rolling historical five-year weighted average cost of grid-scale solar photovoltaic facilities that the Company owns or has rights to through a solar photovoltaic Purchased Power Agreement (PPA); and (ii) applicable Avoided Transmission Capacity Cost, Avoided Distribution Capacity Cost, and Line Losses.

2. Customer Billing

The Company will provide the Customer a monthly bill credit for the Export Energy based on the applicable RCP.

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; if the outstanding credits exceed $25 a check will automatically be issued; otherwise the bill credits will carry forward to the following year.

3. Resource Comparison Proxy Purchase Rate

The RCP will be determined as follows:

- An RCP will be determined for each tranche of new DG Customers, effective July 1 each year without proration. The RCP may not be reduced by more than 10% each year.

- Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before July 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.

- Each Customer's initial RCP will be applicable for 10 years from the time of their interconnection.

- After each Customer's initial 10-year period the bill credit will be based on the purchase rate in effect at that time, and will change from year to year.

4. Definitions

Avoided Cost. In the context of this Plan of Administration, the additional cost APS would incur to acquire electric energy to serve its customers if electricity was not available from on-site distributed generation sources.

Avoided Distribution Capacity Cost. In the context of this Plan of Administration, the net cost of distribution grid equipment and facilities necessary to distribute electricity to APS customers if electricity from on-site distributed generation sources was not available.

Avoided Transmission Capacity Cost. In the context of this Plan of Administration, the additional cost of transmission grid equipment and facilities necessary to transmit electricity to APS customers if electricity from on-site distributed generation sources was not available.

Base Year. For the initial RCP calculation (effective July 1, 2017), the Company's most recent test year, calendar year ending December 31, 2015. Each subsequent annual calculation will use the immediately preceding calendar year as the Base Year. As an example, the RCP that will become effective with the first billing cycle of July 2018 will be calculated with the calendar year ending December 31, 2017 as the Base Year.

Customer(s). For purposes of this Plan of Administration, an APS Customer taking service under a Residential rate schedule.

Export(ed) Energy. Energy generated by an on-site interconnected solar photovoltaic distributed generation source that is greater than the Customer's electric load at any single point in time and flows into the Company's distribution grid.

Levelized Cost. For purposes of this Plan of Administration, the net present value of the overall cost of building and operating a grid-scale solar photovoltaic generating plant, or the net present value of the overall cost to APS of an executed solar photovoltaic PPA, over the economic life of the asset and converted to equal annual amounts.

Line Losses. Electric energy lost as it is transmitted from a supply source (i.e., an electric generation plant) to a delivery point (i.e., the Customer's residence or place of business).

Partial Requirements Service. Electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

Production Tax Credit. The income tax credit available in the State of Arizona for taxpayers that own a qualified renewable energy generator as defined in A.R.S. §43-1083.02 and §43-1164.03 that produces energy after December 31, 2010 and before January 1, 2021. The amount of Production Tax Credit available is limited by facility and by calendar year.

Revenue Requirement. For purposes of this Plan of Administration, the amount of revenue calculated to be recovered in rates for the APS-owned grid-scale solar facilities included in the RCP calculation. Revenue Requirement expenses include depreciation expense, income taxes, property taxes, deferred taxes and tax credits where appropriate, associated operation and maintenance expense, and an approved debt and equity return.

5. System Eligibility

A distributed generation facility must meet all of the following qualifications to be eligible for the RCP:

- Electricity must be generated using solar photovoltaic panels;
- The facility must be interconnected to the Company's distribution grid;
- The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;
- The facility's nameplate capacity cannot be larger than the following electrical service limits:
  a. For 200 Amp service, a maximum of 15 kW-dc,
  b. For 400 Amp service, a maximum of 30 kW-dc,
  c. For 600 Amp service, a maximum of 45 kW-dc,
  d. For 800 Amp service and above, a maximum of 60 kW-dc; and

- For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

SPECIAL CASES

Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the Customer will not be eligible for an initial 10-year lock in the purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this Plan of Administration, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.

Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

6. Calculation of Resource Comparison Proxy Purchase Rate

The RCP is calculated by developing a historical rolling five-year weighted average cost per kWh for all grid-scale renewable solar photovoltaic generating systems used by APS to serve its customers, both APS-owned facilities and facilities from which APS purchases power through an executed PPA. The calculation methodology is as follows:

The first RCP effective on July 1, 2017 is $0.12900/kWh, using 2015 as the Base Year inclusive of adjustments as provided for in Decision No. xxxxx. Subsequent RCPs derived from following the calculations in Steps 1 through 8 below will then be compared to the RCP in effect. If the calculated RCP results in a reduction in the purchase rate from the previous RCP, any such reduction will be no greater than 10% of the previous RCP.

1. Determine appropriate five-year period. The RCP will be calculated using the 5-year period with the Base Year as the final year of the five. Only those grid-scale solar facilities with an in-service date within this 5-year period will be included in the annual RCP calculation.

If there are no grid-scale solar photovoltaic projects in any particular year of the rolling five-year period described above, the rolling 5 year average will be calculated without a project for that particular year. Calculating the RCP without a project for a particular year (i) is the product of the settlement approved in Decision No. xxxx; (ii) is the product of compromise; (iii) does not establish a precedent for how the RCP should be calculated; and (iv) will be revisited in APS's next general rate case.

2. Develop/update annual Revenue Requirement for each APS-owned facility. The Company will calculate revenue requirements for each grid-scale solar photovoltaic generation facility owned by the Company that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual designed output of the facility, including degradation, will be used for this calculation. This step provides an annual revenue requirement cost in dollars for each year of the facility's depreciable life.

3. Incorporate applicable Production Tax Credit. All expected available annual Production Tax Credit tax savings (in dollars) for the above APS facilities will be calculated based on expected annual energy production and subtracted from the annual facility cost derived in Step 2 above for each year.

4. Develop/update annual cost of power from each PPA facility. The Company will calculate an annual cost of purchased power for each facility from which APS purchases power under an executed agreement that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual cost for each of these facilities will be calculated separately for the contract life of each PPA using the contract price and the designed output, including degradation, of the facilities, including contractual escalation factors, as appropriate.

5. Calculate individual facility Levelized Cost. The Levelized Cost for each of the facilities will then be calculated using the data derived in Steps 2 through 4 above. The net present value discount rate used in the Levelized Cost calculations will be calculated using the approved after-tax weighted average cost of capital as determined in the Company's most recent rate case. The result of this calculation step will be a Levelized Cost per MWh for each of the facilities.

6. Calculate weighted Levelized Cost for each facility. The weighted Levelized Cost is calculated by multiplying the cost per MWh derived for each facility in Step 5 by the actual Base year energy production in MWh for each Step 5 facility. The result of this step is an annual weighted cost in dollars for each included facility.

7. Calculate weighted average Levelized Cost for all facilities. The annual weighted average Levelized Cost is determined by dividing the total annual weighted costs for all included facilities by the total Base year energy production MWh. The result of this step is the rolling historical five-year weighted average Levelized Cost per MWh for grid-scale solar photovoltaic facilities on the APS system before any applicable adjustments.

8. Adjustments. An adjustment is then applied to the annual weighted average Levelized Cost per MWh for avoided transmission capacity cost, avoided distribution capacity cost, and line

losses as required in Decision No. 75859. For purposes of this Plan of Administration, and subject to future Commission proceedings, the combined adjustment for these three values is set at $0.02/kWh as provided for in Decision No. xxxxx. This amount is negotiated, does not reflect an actual calculation of system conditions, and establishes no precedent for any future RCP or avoided cost calculations. While future Commission proceedings may establish methodologies for calculation of the adjustments, no changes will be made to this value until the conclusion of the next APS general rate case.

7. Procedural Timeline

The Company will provide Commission Staff and other intervening parties with its annual RCP calculation no later than March 1 each year. Interested parties will file comments to the Company's RCP calculation by April 1. Commission Staff will file its Report by May 15 and request that Staff's Report be considered in the June Open Meeting and be approved so that the new RCP calculation is effective on July 1.

8. Confidential Data

Portions of the data used to calculate APS's annual RCP are competitively/highly confidential and cannot be released to the public. Competitively/highly confidential information will be made reasonably accessible to parties so that they may determine that such data supports the RCP calculation and that the RCP calculation complies with Commission orders. Competitively/highly confidential information includes cost and production data for facilities from which APS purchases energy under a PPA agreement.

9. Schedules

Templates of the spreadsheet used to calculate the RCP are attached:

Schedule 1:	Annual Resource Comparison Proxy Calculation Summary
Schedule 2:	Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost
Schedule 3:	Individual Plant Annual Cost ($/MWh)
Schedule 4:	Individual Plant Energy Production (MWh)
Schedule 5:	Individual Plant Revenue Requirement/PPA Annual Cost ($000)
Schedule 6:	Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits ($000)

Each of these schedules contains competitively/highly confidential PPA data as indicated.

Arizona Public Service Company
Schedule 1: Annual Resource Comparison Proxy Calculation Summary

Competitively/Highly Confidential
Page 1 of 6

= Competitively/Highly Confidential

			Competitively/Highly Confidential				Competitively/Highly Confidential
Year	Project #	Projects	Cost per MWh	1st Year Energy	Weight	Weighted Energy	Weighted Cost (1,000's)
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						

Weighted Cost	
Energy	
Average Cost per MWh	
Grid Scale Adjustment	
Cost per MWh after Grid-Scale Adjustment	
Trans, Dist, and Losses Adjustment	
Final Resource Comparison Proxy (RCP)	

Arizona Public Service Company
Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost

Competitively/Highly Confidential

Project	RFP Year	Start Date	Start Year	Levelized Cost (Base Year)	GWH (1st Year)

= Competitively/Highly Confidential

Arizona Public Service Company
Schedule 3: Individual Plant Annual Cost ($/MWh)

Project	Levelized Cost per MWh	BY YEAR: 2011 through 2046
		= Competitively/Highly Confidential

Arizona Public Service Company
Schedule 4: Individual Plant Energy Production (MWh)

Discount Rate		
		= Competitively/Highly Confidential
Project	Levelized Energy	BY YEAR: 2011 through 2046

Arizona Public Service Company

Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost ($000)

Discount Rate		
		= Competitively/Highly Confidential
Project	Levelized Cost	BY YEAR: 2011 through 2046

Arizona Public Service Company
Schedule 6: Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits ($000)

Discount Rate		
		= Competitively/Highly Confidential
Project	Levelized Cost	BY YEAR: 2011 through 2046

RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

AVAILABILITY

This rate rider is available to qualifying residential and non-residential partial requirements Customers with an on-site renewable distributed generation system. Residential Customers with an interconnected on-site solar photovoltaic system are not eligible for this rate rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program and exports energy through the Company's distribution grid. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods. On-peak export energy will be netted against on-peak energy from the Company and off-peak export energy will be netted against off-peak energy, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December bill, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

BILLING DETAILS

1. All terms and charges in the customer's rate schedule continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for any remaining export energy at the purchase price.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. The generator must be interconnected to the Company's distribution grid;

2. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;

3. For qualifying residential facilities, the nameplate capacity cannot be larger than the following electrical service limits:
   a. For 200 Amp service, a maximum of 15 kW-dc.
   b. For 400 Amp service, a maximum of 30 kW-dc.
   c. For 600 Amp service, a maximum of 45 kW-dc.
   d. For 800 Amp service and above, a maximum of 60 kW-dc; and

4. For all qualifying residential and non-residential facilities over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

   a. Provides part of the Customer's energy requirements at the site where the system is installed;

   b. Uses renewable resources, as defined by the Arizona Corporation Commission, including a fuel cell with the chemical reaction derived from renewable resources or a combined heat and power (CHP) facility as defined by A.A.C. R14-2-2302, to generate energy; and

c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

5. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

AVAILABILITY

This rate rider is available to Customers that qualify for the residential solar grandfathering program. It may be used in conjunction with the residential Legacy rate schedules for distributed generation systems.

This rate rider is frozen effective July 1, 2017. This means a residential Customer that is already taking service under this rate rider by that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider. Instead, the residential Customer will be served under an applicable retail rate of their choice and Rate Rider RCP, or a subsequent replacement rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program. A partial requirements Customer has on-site generation that serves some of their electrical requirements and relies on the Company for additional electrical services. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods, i.e. on-peak export energy will be netted against on-peak energy from the Company and vice-versa, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December billing cycle, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

$0.02895	per kWh

The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

aps

RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR ON-SITE RENEWABLE DISTRIBUTED GENERATION NET METERING

BILLING DETAILS

1. All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.

2. If the Customer terminates electric service, the Company will issue a check for the remaining export energy at the purchase price.

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to July 1, 2017 and otherwise qualify for this rate rider may continue service under the grandfathering program.

2. Customers who (i) submit a complete application for interconnection to the Company by July 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application, and otherwise qualify for this rate rider may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.

3. The grandfathering period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.

4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.

5. Customers may not move their solar generation unit to another site.

6. The grandfathering may be transferred to a new customer purchasing the home.

7. The Customer may remain on their current Legacy rate schedule but may not move between alternate grandfathered Legacy rate schedules.

8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.

9. Frozen Rate Rider Legacy LFCR-DG will continue to apply.

10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.

2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.

3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection or purchase agreement.

4. A Net Metering Facility is an on-site distributed generation system that:

   a. Provides part of the Customer's energy requirements at the site where the system is installed;

   b. Uses renewable resources, as defined by the Arizona Corporation Commission, to generate energy; and

   c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

Exhibit 12.1

PINNACLE WEST CAPITAL CORPORATION
RATIO OF EARNINGS TO FIXED CHARGES
(dollars in thousands)

	Three Months Ended March 31,	Twelve Months Ended December 31,				
	2017	2016	2015	2014	2013	2012
Earnings:						
Income from continuing operations attributable to common shareholders	$ 23,312	$ 442,034	$ 437,257	$ 397,595	$ 406,074	$ 387,380
Income taxes	4,211	236,411	237,720	220,705	230,591	237,317
Fixed charges	54,031	213,973	202,465	208,226	206,089	219,437
Total earnings	$ 81,554	$ 892,418	$ 877,442	$ 826,526	$ 842,754	$ 844,134
Fixed Charges:						
Interest expense	$ 51,864	$ 205,720	$ 194,964	$ 200,950	$ 201,888	$ 214,616
Estimated interest portion of annual rents	2,167	8,253	7,501	7,276	4,201	4,821
Total fixed charges	$ 54,031	$ 213,973	$ 202,465	$ 208,226	$ 206,089	$ 219,437
Ratio of Earnings to Fixed Charges (rounded down)	1.50	4.17	4.33	3.96	4.08	3.84

Exhibit 12.2

ARIZONA PUBLIC SERVICE COMPANY
RATIO OF EARNINGS TO FIXED CHARGES
(dollars in thousands)

	Three Months Ended March 31,	Twelve Months Ended December 31,				
	2017	2016	2015	2014	2013	2012
Earnings:						
Income from continuing operations attributable to common shareholders	$ 23,162	$ 462,141	$ 450,274	$ 421,219	$ 424,969	$ 395,497
Income taxes	8,648	245,842	245,841	237,360	245,095	244,396
Fixed charges	52,944	210,776	199,458	204,198	202,457	214,227
Total earnings	$ 84,754	$ 918,759	$ 895,573	$ 862,777	$ 872,521	$ 854,120
Fixed Charges:						
Interest charges	$ 49,619	$ 197,811	$ 187,499	$ 193,119	$ 194,616	$ 205,533
Amortization of debt discount	1,177	4,760	4,793	4,168	4,046	4,215
Estimated interest portion of annual rents	2,148	8,205	7,166	6,911	3,795	4,479
Total fixed charges	$ 52,944	$ 210,776	$ 199,458	$ 204,198	$ 202,457	$ 214,227
Ratio of Earnings to Fixed Charges (rounded down)	1.60	4.35	4.49	4.22	4.30	3.98

Exhibit 12.3

PINNACLE WEST CAPITAL CORPORATION
RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDEND REQUIREMENTS
(dollars in thousands)

	Three Months Ended March 31,	Twelve Months Ended December 31,				
	2017	2016	2015	2014	2013	2012
Earnings:						
Income from continuing operations attributable to common shareholders	$ 23,312	$ 442,034	$ 437,257	$ 397,595	$ 406,074	$ 387,380
Income taxes	4,211	236,411	237,720	220,705	230,591	237,317
Fixed charges	54,031	213,973	202,465	208,226	206,089	219,437
Total earnings	$ 81,554	$ 892,418	$ 877,442	$ 826,526	$ 842,754	$ 844,134
Fixed Charges:						
Interest expense	$ 51,864	$ 205,720	$ 194,964	$ 200,950	$ 201,888	$ 214,616
Estimated interest portion of annual rents	2,167	8,253	7,501	7,276	4,201	4,821
Total fixed charges	$ 54,031	$ 213,973	$ 202,465	$ 208,226	$ 206,089	$ 219,437
Preferred Stock Dividend Requirements:						
Income before income taxes attributable to common shareholders	$ 27,523	$ 678,445	$ 674,977	$ 618,300	$ 636,665	$ 624,697
Net income from continuing operations attributable to common shareholders	23,312	442,034	437,257	397,595	406,074	387,380
Ratio of income before income taxes to net income	1.18	1.53	1.54	1.56	1.57	1.61
Preferred stock dividends	—	—	—	—	—	—
Preferred stock dividend requirements — ratio (above) times preferred stock dividends	$ —	$ —	$ —	$ —	$ —	$ —
Fixed Charges and Preferred Stock Dividend Requirements:						
Fixed charges	$ 54,031	$ 213,973	$ 202,465	$ 208,226	$ 206,089	$ 219,437
Preferred stock dividend requirements	—	—	—	—	—	—
Total	$ 54,031	$ 213,973	$ 202,465	$ 208,226	$ 206,089	$ 219,437
Ratio of Earnings to Fixed Charges (rounded down)	1.50	4.17	4.33	3.96	4.08	3.84

Exhibit 31.1

CERTIFICATION

I, Donald E. Brandt, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2017

/s/ Donald E. Brandt

Donald E. Brandt

Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, James R. Hatfield, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2017

/s/ James R. Hatfield

James R. Hatfield
Executive Vice President and Chief Financial Officer

Exhibit 31.3

CERTIFICATION

I, Donald E. Brandt, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2017

/s/ Donald E. Brandt

Donald E. Brandt
Chairman, President and Chief Executive Officer

Exhibit 31.4

CERTIFICATION

I, James R. Hatfield, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Arizona Public Service Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 2, 2017

/s/ James R. Hatfield

James R. Hatfield

Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Donald E. Brandt, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the quarter ended March 31, 2017 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 2, 2017

/s/ Donald E. Brandt
Donald E. Brandt
Chairman, President and
Chief Executive Officer

I, James R. Hatfield, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Pinnacle West Capital Corporation for the quarter ended March 31, 2017 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pinnacle West Capital Corporation.

Date: May 2, 2017

/s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer

Exhibit 32.2

CERTIFICATION
OF
CHIEF EXECUTIVE OFFICER
AND
CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Donald E. Brandt, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Arizona Public Service Company for the quarter ended March 31, 2017 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: May 2, 2017

/s/ Donald E. Brandt
Donald E. Brandt
Chairman, President and
Chief Executive Officer

I, James R. Hatfield, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Quarterly Report on Form 10-Q of Arizona Public Service Company for the quarter ended March 31, 2017 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Quarterly Report on Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Arizona Public Service Company.

Date: May 2, 2017

/s/ James R. Hatfield
James R. Hatfield
Executive Vice President and
Chief Financial Officer