THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)

Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)

Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Arizona Public Service Company	**End of** 2015/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ____________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Arizona Public Service Company	02 Year/Period of Report End of 2015/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 400 North 5th Street, Phoenix, 85004	
05 Name of Contact Person Jeffrey B. Guldner	06 Title of Contact Person SVP Public Policy
07 Address of Contact Person *(Street, City, State, Zip Code)* 400 North 5th Street, Phoenix, 85004	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(602) 250-2952	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Denise R. Danner	03 Signature Denise R. Danner	04 Date Signed *(Mo, Da, Yr)* 03/17/2016
02 Title VP, Controller & Chief Acct Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

James R. Hatfield, Executive Vice President & Chief Financial Officer, 400 N. 5th Street, Phoenix, AZ 85004

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Arizona - February 6, 1920

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

State of Arizona - Class A Electric Utility

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

All of the outstanding shares of common stock of the Company are owned by Pinnacle West Capital Corporation (formerly AZP Group Inc.) which became the Company's corporate parent effective April 29, 1985 pursuant to a corporate restructuring. The corporate restructuring did not affect any of its outstanding debt securities, all of which remain obligations of the Company.

See Pinnacle West Capital Corporation's Annual Report on Form 10-K for the fiscal year ended December 31, 2015, as filed with the Securities and Exchange Commission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Bixco, Inc.	Inactive	100	
2				
3	APS Foundation, Inc.	A non-profit corporation	N/A	(1)
4		which makes distributions		
5		to charitable organizations		
6				
7	Axiom Power Solutions, Inc.	Inactive	100	
8				
9	PWENewco, Inc.	Inactive	100	
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 103   Line No.: 3   Column: d

(1) The APS Foundation is an Arizona non-profit corporation. The APS Foundation has no stockholders or members, and all voting power is held by the Board of Directors.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President & Chief Executive Officer	Donald E. Brandt	1,275,458
2			
3	Executive Vice President & Chief Operating Officer	Mark A. Schiavoni	638,333
4			
5	Executive Vice President & Chief Nuclear Officer	Randall K. Edington	1,048,542
6			
7	Executive Vice President & General Counsel	David P. Falck	543,083
8			
9	Executive Vice President & Chief Financial Officer	James R. Hatfield	592,042
10			
11	Senior Vice President, Site Operations	Robert S. Bement	404,583
12			
13	Senior Vice President, Transmission, Distribution &	Daniel T. Froetscher	341,771
14	Customers		
15			
16	Senior Vice President, Public Policy	Jeffrey B. Guldner	381,250
17			
18	Vice President, Controller & Chief Accounting Officer	Denise R. Danner	322,500
19			
20	Vice President, Transmission and Distribution Operations	Patrick Dinkel	284,625
21			
22	Vice President, Communications	John S. Hatfield	288,581
23			
24	Vice President, Resource Management	Tammy D. McLeod	281,967
25			
26	Vice President & Treasurer	Lee R. Nickloy	287,500
27			
28	Vice President, Human Resources	Barbara M. Gomez	335,000
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

Schedule Page: 104 Line No.: 1 Column: c

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

Schedule Page: 104 Line No.: 7 Column: c

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

Schedule Page: 104 Line No.: 9 Column: c

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

Schedule Page: 104 Line No.: 18 Column: c

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

Schedule Page: 104 Line No.: 26 Column: c

This amount represents the officer’s total salary, and (for purposes of this report) has not been adjusted to reflect an allocation of the officer’s total salary to any affiliated company where the person also serves as an officer.

Schedule Page: 104 Line No.: 28 Column: a

Designated as Section 16 Officer on May 20, 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Donald E. Brandt, Chairman, President and CEO	Phoenix, Arizona
2		
3	Susan Clark-Johnson	Paradise Valley, Arizona
4		
5	Denis A. Cortese	Fountain Hills, Arizona
6		
7	Richard P. Fox	Carefree, Arizona
8		
9	Michael L. Gallagher	Phoenix, Arizona
10		
11	Roy A. Herberger, Jr.	Phoenix, Arizona
12		
13	Dale E. Klein	Austin, Texas
14		
15	Humberto S. Lopez	Tucson, Arizona
16		
17	Kathryn L. Munro	La Jolla, California
18		
19	Bruce J. Nordstrom	Flagstaff, Arizona
20		
21	David P. Wagener	New York, New York
22		
23	Note: Currently there is no Executive	
24	Committee of the Board of Directors	
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 3 Column: b

Ms. Clark-Johnson passed away in January 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

INFORMATION ON FORMULA RATES

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff, Volume 2	ER11-3638
2	FERC Electric Tariff, Volume 5	ER09-1402
3	FERC Electric Rate Schedule No. 182	ER11-3926
4	WestConnect Point-to-Point Regional Transmission	ER13-1296
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 106 Line No.: 4 Column: a

The WestConnect Tariff does not have any direct FERC Form No. 1 inputs. However the relevant input to the WestConnect Tariff is APS's FERC Electric Tariff Volume 2 which does have FERC Form No. 1 inputs. Out of an abundance of caution, APS included the WestConnect Tariff on page 106 of the FERC Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20150515-5146	05/15/2015	ER11-3638	See Footnote	FERC Electric Tariff, Volume 2
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 1061 Line No.: 1 Column: d

Informational Filing - Annual Update of Formula Transmission Service Rates - Arizona Public Service Company under ER11-3638.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44		Page 106b intentionally left blank		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent Arizona Public Service Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. The town of Quartzsite franchise was approved on March 10, 2015. As with all of Arizona Public Service Company's ("APS") municipal franchises, the referenced franchises include a 2% franchise fee, which is collected from the customers in the same way that transaction privilege tax (sales tax) is collected, and are renewed for terms of 25 years. County franchises do not include the collection and payment of franchise fees.

2. None.

3. None.

4. None.

5. During second quarter 2015, the following transmission line construction was completed and energized:

Hassayampa-N.Gila 500kV:

Reason for addition: This project will increase the import capability for the Yuma area and export/scheduling capability from the Palo Verde area and to provide access to both solar and gas resources. This project will also allow the system to accommodate generation interconnection requests.
Voltage: 500kV
End Points: Hassayampa switchyard & North Gila substation
Construction Start: September 17, 2013
Line Construction Completed: April 30, 2015
Substation Construction Completed: May 23, 2015
HANG 2 Line Energization: May 26, 2015
Miles Constructed: 113

Arizona Corporation Commission Decision Information:
CEC #135 was originally authorized in Decision No. 70127 and modified in Decision No. 74206 (both in Docket No. L-00000D-07-0566-00135)

Palm Valley-Trilby Wash 230kV:

Reason for addition: This project will serve the need for electric energy in the western Phoenix Metropolitan area and additional import capability into the greater Phoenix Metro area. The Trilby Wash substation will be a new transmission source for the far northwestern part of the valley, which will provide improved system reliability for communities in the area; such as El Mirage, Surprise, Youngtown, Goodyear, and Buckeye.
Voltage: 230kV
End Points: Palm Valley substation and Trilby Wash substation
Construction Start: September 23, 2014
Line Construction Completed: May 8, 2015
Substation Construction Completed: May 21, 2015
Palm Valley – Trilby Wash Energization: May 26, 2015
Miles Constructed: 15 miles

Arizona Corporation Commission Decision Information:
CEC 122 (WVS) – Docket No. L-00000D-03-0122, Decision No. 66646
CEC 127 (WVN) – Docket No. L-00000D-04-0127, Decision No. 67828

No other important extension or reduction of the transmission or distribution system service territory occurred in 2015 for APS. Only our normal additions due to customer and load growth were experienced.

6. **Lines of Credit and Short-Term Borrowings**

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

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

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

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

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

Long-Term Debt

All of APS's debt is unsecured. The following table presents the components of long-term debt on the Comparative Balance Sheets outstanding at December 31, 2015 and 2014 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2015	December 31, 2014
APS				
Pollution control bonds:				
Variable	2029-2038	(b)	$ 92,405	$ 156,405
Fixed	2024-2034	1.75%-5.75%	211,150	249,300
Total pollution control bonds			303,555	405,705
Other long-term debt	2016-2045	1.02%-8.75%	3,453,695	2,902,578
Unamortized discount			(10,374)	(9,206)
Unamortized premium			4,686	4,866
Total Long-Term Debt			$ 3,751,562	$ 3,303,943

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.
(b) The weighted-average rate for the variable rate pollution control bonds was 0.01%-0.24% at December 31, 2015 and 0.03%-0.27% at December 31, 2014.

The following table shows principal payments due on APS's total long-term debt (dollars in thousands):

Year	APS
2016	$ 357,580
2017	—
2018	82,000
2019	500,000
2020	250,000
Thereafter	2,567,670
Total	$ 3,757,250

Credit Facilities and Debt Issuances

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

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

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

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

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

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A.

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

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

Contractual Obligations

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

	2016	2017-2018	2019-2020	Thereafter	Total
Long-term debt payments, including interest: (a)	$ 542	$ 414	$ 1,011	$ 4,422	$ 6,389
Fuel and purchased power commitments (b)	643	1,174	1,064	7,559	10,440
Renewable energy credits (c)	42	80	80	432	634
Purchase obligations (d)	233	512	37	213	995
Coal reclamation	15	34	39	262	350
Nuclear decommissioning funding requirements	2	4	4	62	72
Operating lease payments	32	61	57	290	440
Total contractual commitments	$ 1,509	$ 2,279	$ 2,292	$ 13,240	$19,320

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

(b) Our fuel and purchased power commitments include purchases of coal, electricity, natural gas, renewable energy, nuclear fuel, and natural gas transportation. These amounts include commitments incurred assuming an additional 7% in the 2016 Coal Supply Agreement.

(c) Contracts to purchase renewable energy credits in compliance with the Arizona Renewable Energy Standard and Tariff ("RES").

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

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

Financial Assurances

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

Authorizations

On February 6, 2013, the ACC issued a financing order (Decision No. 73659) in which it, subject to specified parameters and procedures, (a) approved APS's short-term debt authorization equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power), (b) approved an increase in APS's long-term debt authorization from $4.2 billion to $5.1 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs, and (c) authorized APS to enter into derivative financial instruments for the purpose of managing interest rate risk associated with its long- and short-term debt. This financing order is set to expire on December 31, 2017.

APS's issuances of short-term debt are authorized by the ACC in its Decision No. 73659 and/or by Arizona Revised Statutes Section 40-302.D and the issuances of long-term debt are authorized by the ACC in its Decision No. 73659.

7. None.

8. The union and non-union annualized wage scale increases during 2015 through December 31, 2015, were as follows:

	Type of Cost	Number of Increases	Annualized Costs
a.	Union Negotiated	1,455	$ 2,467,363
b.	Non-Union Base Salary Increases	3,783	10,879,983
c.	Special Increases	517	1,576,453
d.	Promotions	856	5,846,064
Total		6,611	$ 20,769,863

COMMENTS:

a. There were general wage increases for both the IBEW (averaging 2%) and the USPA (averaging approximately 2%) during second quarter.

b. The overall non-union employee merit budget was 3.0%. Actual merit adjustments ranged from 0% to 8% based upon an employee's performance and their pay position within the salary range. Merit pay awards were added to base pay.

c. Salary adjustments to base pay were awarded to non-union employees throughout the year in special instances.

d. Promotions were awarded to union and non-union employees due to changes in job functions or grade level changes.

9. **Legal Proceedings**

I. LITIGATION & ENVIRONMENTAL MATTERS UPDATE

Environmental Matters

Climate Change

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

(“CO_2”) equivalent emitted.

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

Regulatory Initiatives. In 2009, EPA determined that GHG emissions endanger public health and welfare. As a result of this “endangerment finding,” EPA determined that the Clean Air Act required new regulatory requirements for new and modified major GHG emitting sources, including power plants. APS will generally be required to consider the impact of GHG emissions as part of its traditional New Source Review ("NSR") analysis for new major sources and major modifications to existing plants.

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

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

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

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

The legality of the Clean Power Plan is being challenged in the U.S. Court of Appeals for the D.C. Circuit;

the parties raising this challenge include, among others, the ACC. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan pending judicial review of the rule, which temporarily delays compliance obligations under the Clean Power Plan. We cannot predict the extent of such delay.

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

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

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

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

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

Company Response to Climate Change Initiatives. We have undertaken a number of initiatives that address emission concerns, including renewable energy procurement and development, promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency. APS currently has a diverse portfolio of renewable resources, including solar, wind, geothermal, biogas, and biomass, and we expect the percentage of renewable energy in our resource portfolio to increase over the coming years.

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

EPA Environmental Regulation

Regional Haze Rules. In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal land, EPA) to determine what pollution control technologies constitute the best available retrofit technology ("BART") for certain older major stationary sources, including fossil-fired power plants. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis.

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

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

On December 5, 2012, EPA issued a final BART rule applicable to Cholla. EPA approved ADEQ's BART emissions limits for sulfur dioxide ("SO_2") and emissions of particulate matter ("PM"), but added a SO_2 removal efficiency requirement of 95%. In addition, EPA disapproved ADEQ's BART determinations for oxides of nitrogen ("NO_x") and promulgated a Federal Implementation Plan ("FIP") establishing a new, more stringent "bubbled" NO_x emission rate applicable to the two BART-eligible Cholla units owned by APS and the other BART-eligible unit owned by PacifiCorp.

APS believes that EPA's final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

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

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

Navajo Plant. On January 18, 2013, EPA issued a proposed BART rule for the Navajo Plant, which would require installation of SCR technology in order to achieve a new, more stringent plant-wide NO_X emission limit. In addition, EPA proposed a "better than BART" alternative and solicited comment on other options that could set longer time frames for installing pollution controls if the Navajo Plant can achieve additional emission reductions. On July 26, 2013, a group of stakeholders, including SRP, the operating agent for the Navajo Plant, submitted to EPA two suggested alternatives to BART, which would achieve greater NO_X emission reductions and result in greater reasonable progress toward the national visibility goal than EPA's proposed BART determination. On July 28, 2014, EPA issued a final Navajo Plant BART rule approving the alternative stakeholder plan. Depending on which alternate operating scenario the Navajo Plant participants ultimately select, the required NO_X emission reductions could be achieved by either closing one of the three 750 MW units at the plant or curtailing energy production across all three units, such that the emission reductions are commensurate with the closure of approximately one of the Navajo Plant units. APS estimates that its share of costs for upgrades at the Navajo Plant, based on EPA's FIP, could be up to approximately $200 million. In October 2014, a coalition of environmental groups, an Indian tribe, and others filed petitions for review in the United States Court of Appeals for the Ninth Circuit asking the Court to review EPA's final BART rule for the Navajo Plant. We cannot predict the outcome of this petition.

Mercury and other Hazardous Air Pollutants. In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excluding costs related to Cholla Unit 2, which was closed on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in *Michigan vs. EPA* reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

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

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

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

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

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

Clean Air Act Citizen Lawsuit. On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners participants alleging violations of the NSR provisions of the Clean Air Act. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the Clean Air Act's New Source Performance Standards ("NSPS") program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

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

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

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

Manufactured Gas Plant Sites. Certain properties which APS now owns or which were previously owned by it or its corporate predecessors were at one time sites of, or sites associated with, manufactured gas plants. APS is taking action to voluntarily remediate these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations or cash flows.

Navajo Nation Environmental Issues

Four Corners and the Navajo Plant are located on the Navajo Reservation and are held under easements granted by the federal government, as well as leases from the Navajo Nation.

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act, and the Navajo Nation Pesticide Act (collectively, the "Navajo Acts"). The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water, and pesticide activities, including those activities that occur at Four Corners and the Navajo Plant. On October 17, 1995, the Four Corners participants and the Navajo Plant participants each filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, challenging the applicability of the Navajo Acts as to Four Corners and the Navajo Plant. The Court has stayed these proceedings pursuant to a request by the parties, and the parties are seeking to negotiate a settlement.

In April 2000, the Navajo Nation Council approved operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. APS believes the Navajo Nation exceeded its authority when it adopted the operating permit regulations. On July 12, 2000, the Four Corners participants and the Navajo Plant participants each filed a petition with the Navajo Supreme Court for review of these regulations. Those proceedings have been stayed, pending the settlement negotiations mentioned above. APS cannot currently predict the outcome of this matter.

On May 18, 2005, APS, SRP, as the operating agent for the Navajo Plant, and the Navajo Nation executed a Voluntary Compliance Agreement to resolve their disputes regarding the Navajo Nation Air Pollution Prevention and Control Act. As a result of this agreement, APS sought, and the courts granted, dismissal of the pending litigation in the Navajo Nation Supreme Court and the Navajo Nation District Court, to the extent the claims relate to the Clean Air Act. The agreement does not address or resolve any dispute relating to other Navajo Acts. APS cannot currently predict the outcome of this matter.

Water Supply

Assured supplies of water are important for APS's generating plants. At the present time, APS has adequate water to meet its needs. However, the Four Corners region, in which Four Corners is located, has been experiencing drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future operations of the plant. The effect of the drought cannot be fully assessed at this time, and APS cannot predict the ultimate outcome, if any, of the drought or whether the drought will adversely affect the amount of power available, or the price thereof, from Four Corners.

Conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions, which, in addition to future supply conditions, have the potential to impact APS's operations.

San Juan River Adjudication. Both groundwater and surface water in areas important to APS's operations have been the subject of inquiries, claims, and legal proceedings, which will require a number of years to resolve. APS is one of a number of parties in a proceeding, filed March 13, 1975, before the Eleventh Judicial District Court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss. In addition, APS is a party to a water contract that allows the company to secure water for Four Corners in the event of a water shortage and is a party to a shortage sharing agreement, which provides for the apportionment of water supplies to Four Corners in the event of a water shortage in the San Juan River Basin.

Gila River Adjudication. A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Arizona Superior Court. Palo Verde is located within the geographic area subject to the summons. APS's rights and the rights of the other Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this action. As operating agent of Palo Verde, APS filed claims that dispute the court's jurisdiction over the Palo Verde participants' groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Several of APS's other power plants are also located within the geographic area subject to the summons. APS's claims dispute the court's jurisdiction over APS's groundwater rights with respect to these plants. Alternatively, APS seeks confirmation of such rights. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower court's criteria for resolving groundwater claims. Litigation on both of these issues has continued in the trial court. In December 2005, APS and other parties filed a petition with the Arizona Supreme Court requesting interlocutory review of a September 2005 trial court order regarding procedures for determining whether groundwater pumping is affecting surface water rights. The Arizona Supreme Court denied the petition in May 2007, and the trial court is now proceeding with implementation of its 2005 order. No trial date concerning APS's water rights claims has been set in this matter.

Little Colorado River Adjudication. APS has filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court, which was originally filed on September 5, 1985. APS's groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and, therefore, is potentially at issue in the case. APS's claims dispute the court's jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. Other claims have been identified as ready for litigation in motions filed with the court. No trial date concerning APS's water rights claims has been set in this matter.

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

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against DOE in the United States Court of Federal Claims ("Court of Federal Claims"). The lawsuit sought to recover damages incurred due to DOE's breach of the Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste ("Standard Contract") for failing to accept Palo Verde's spent nuclear fuel and high level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the Nuclear Waste Policy Act. On August 18, 2014, APS and DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of current reported net income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through 2016.

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

Southwest Power Outage

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

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

Notice of Intent to Sue Related to Four Corners

On December 21, 2015, several environmental groups filed a notice of intent to sue with the Office of Surface Mining Reclamation and Enforcement ("OSM") and other federal agencies under the Endangered Species

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

New Mexico Tax Matter

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

II. REGULATORY MATTERS

Retail Rate Case Filings with the Arizona Corporation Commission

Upcoming Rate Case Filing

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

Prior Rate Case Filing

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. APS requested that the increase become effective July 1, 2012. The request would have increased the average retail customer bill by approximately 6.6%. On January 6, 2012, APS and other parties to the general retail rate case entered into the 2012 Settlement Agreement detailing the terms upon which the parties agreed to settle the rate case. On May 15, 2012, the ACC approved the 2012 Settlement Agreement without material modifications.

Settlement Agreement

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

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

An authorized return on common equity of 10.0%;

A capital structure comprised of 46.1% debt and 53.9% common equity;

A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;

Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:

Deferral of increases in property taxes of 25% in 2012, 50% in 2013 and 75% for 2014 and subsequent years if Arizona property tax rates increase; and

Deferral of 100% in all years if Arizona property tax rates decrease;

A procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners (APS made its filing under this provision on December 30, 2013, see "Four Corners" below);

Implementation of a "Lost Fixed Cost Recovery" rate mechanism to support energy efficiency and distributed renewable generation;

Modifications to the Environmental Improvement Surcharge to allow for the recovery of carrying costs for capital expenditures associated with government-mandated environmental controls, subject to an existing cents per kWh cap on cost recovery that could produce up to approximately $5 million in revenues annually;

Modifications to the PSA, including the elimination of the 90/10 sharing provision;

A limitation on the use of the RES surcharge and the DSMAC to recoup capital expenditures not required under the terms of the 2009 Settlement Agreement;

Allowing a negative credit that existed in the PSA rate to continue until February 2013, rather than being reset on the anticipated July 1, 2012 rate effective date;

Modification of the TCA to streamline the process for future transmission-related rate changes; and

Implementation of various changes to rate schedules, including the adoption of an experimental "buy-through" rate that could allow certain large commercial and industrial customers to select alternative sources of generation to be supplied by APS.

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

Cost Recovery Mechanisms

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

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

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

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

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

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

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

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

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

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

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

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

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

PSA Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;

An adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;

The PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through January 31) (see the following bullet point);

The PSA rate includes (a) a “Forward Component,” under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a “Historical Component,” under which differences between actual fuel and purchased power costs and those recovered through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a “Transition Component,” under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and

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

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

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

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

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

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

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

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

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

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

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

Net Metering

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

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

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

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

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

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

Four Corners

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

As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third-parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

Cholla

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

10. None.

11. (RESERVED)

12. N/A

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

13. **Board and Officer Elections, Retirements, Resignations and Changes During 2015:**

Directors –

Susan Clark-Johnson, passed away on January 28, 2015.

Officers –

Brad Berryman, Vice President Site Operations and General Plant Manager, Palo Verde Nuclear Generating Station, resigned January 6, 2015.

Barbara Lockwood, formerly General Manager of Regulatory Policy and Compliance, became Vice President of Regulation on October 21, 2015.

14. N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	17,080,761,645	16,362,625,127
3	Construction Work in Progress (107)	200-201	713,287,335	591,741,133
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		17,794,048,980	16,954,366,260
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,402,411,202	6,173,810,334
6	Net Utility Plant (Enter Total of line 4 less 5)		11,391,637,778	10,780,555,926
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	99,557,610	91,065,520
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		845	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		269,365,593	268,754,495
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	146,227,544	143,553,701
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		222,696,504	216,266,314
14	Net Utility Plant (Enter Total of lines 6 and 13)		11,614,334,282	10,996,822,240
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,088,897	5,464,063
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,562,163	1,553,033
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	713,865,964
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		918,129,534	149,570,873
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		15,959,853	24,809,980
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		938,616,121	892,157,847
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		113,921	4,169,751
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		2,868,225	269,525
38	Temporary Cash Investments (136)		19,074,143	75,780
39	Notes Receivable (141)		4	924,992
40	Customer Accounts Receivable (142)		210,352,179	213,576,551
41	Other Accounts Receivable (143)		64,070,363	84,033,993
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,124,684	3,094,461
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		5,261	100,543
45	Fuel Stock (151)	227	38,345,560	32,263,222
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	232,937,102	219,554,841
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	7,351,348	4,833,925

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	1,296,535	-666,160
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		32,489,126	32,841,380
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		96,240,054	100,532,928
62	Miscellaneous Current and Accrued Assets (174)		51,231,500	78,019,463
63	Derivative Instrument Assets (175)		53,367,798	53,372,804
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		15,959,853	24,809,980
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		790,658,582	795,999,097
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		27,895,985	24,641,862
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,334,174,106	1,147,084,875
73	Prelim. Survey and Investigation Charges (Electric) (183)		5,982,037	6,170,684
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		214,803	311,939
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	122,124,425	121,840,013
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		17,890,348	17,845,003
82	Accumulated Deferred Income Taxes (190)	234	852,940,853	851,497,364
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,361,222,557	2,169,391,740
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		15,704,831,542	14,854,370,924

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	178,162,368	178,162,368
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		2,398,807,686	2,398,807,686
7	Other Paid-In Capital (208-211)	253	18,400,365	18,400,365
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	37,511,652	37,511,652
11	Retained Earnings (215, 215.1, 216)	118-119	2,148,493,189	1,968,719,143
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-27,097,083	-48,332,631
16	Total Proprietary Capital (lines 2 through 15)		4,679,254,873	4,478,245,279
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	303,555,000	405,705,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	3,453,695,075	2,902,577,791
22	Unamortized Premium on Long-Term Debt (225)		4,686,330	4,866,574
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		10,373,885	9,206,464
24	Total Long-Term Debt (lines 18 through 23)		3,751,562,520	3,303,942,901
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		186,209,060	193,313,000
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		515,308	873,663
29	Accumulated Provision for Pensions and Benefits (228.3)		505,338,198	467,078,279
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		294,496	359,288
32	Long-Term Portion of Derivative Instrument Liabilities		92,213,397	80,257,408
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		1,613,757	2,732,932
34	Asset Retirement Obligations (230)		443,576,528	390,749,875
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,229,760,744	1,135,364,445
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	147,400,000
38	Accounts Payable (232)		291,567,656	289,929,529
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		84,985,708	92,873,341
41	Customer Deposits (235)		73,072,613	72,306,606
42	Taxes Accrued (236)	262-263	154,011,438	142,296,215
43	Interest Accrued (237)		56,807,168	53,343,674
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		6,131	422
48	Miscellaneous Current and Accrued Liabilities (242)		169,328,681	147,671,684
49	Obligations Under Capital Leases-Current (243)		7,103,830	21,497,000
50	Derivative Instrument Liabilities (244)		204,130,617	164,873,458
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		92,213,397	80,257,408
52	Derivative Instrument Liabilities - Hedges (245)		3,268,559	4,178,126
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		1,613,757	2,732,932
54	Total Current and Accrued Liabilities (lines 37 through 53)		950,455,247	1,053,379,715
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		115,609,383	123,052,363
57	Accumulated Deferred Investment Tax Credits (255)	266-267	187,080,422	178,607,210
58	Deferred Gains from Disposition of Utility Plant (256)		12,760	4,586,550
59	Other Deferred Credits (253)	269	268,889,494	276,477,009
60	Other Regulatory Liabilities (254)	278	879,524,513	899,167,049
61	Unamortized Gain on Reaquired Debt (257)		328,382	371,685
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		3,032,795,795	2,877,990,083
64	Accum. Deferred Income Taxes-Other (283)		609,557,409	523,186,635
65	Total Deferred Credits (lines 56 through 64)		5,093,798,158	4,883,438,584
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		15,704,831,542	14,854,370,924

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,519,645,174	3,522,222,472		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,768,447,876	1,865,748,372		
5	Maintenance Expenses (402)	320-323	231,357,405	241,133,018		
6	Depreciation Expense (403)	336-337	385,402,361	367,155,333		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	70,077	-923,459		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	70,747,118	71,678,968		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	10,873,443	453,060		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		55,045	55,045		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		6,688,721	278,697		
13	(Less) Regulatory Credits (407.4)		-293,623	31,942,337		
14	Taxes Other Than Income Taxes (408.1)	262-263	197,728,627	198,164,185		
15	Income Taxes - Federal (409.1)	262-263	21,013,707	39,109,116		
16	- Other (409.1)	262-263	8,798,827	15,398,957		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	838,754,779	1,152,367,603		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	608,242,675	960,800,421		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		4,573,793	4,573,793		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		500,880	53,143		
23	Losses from Disposition of Allowances (411.9)		447,680	393,324		
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,927,361,941	2,953,642,525		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		592,283,233	568,579,947		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
3,519,645,174	3,522,222,472					2
						3
1,768,447,876	1,865,748,372					4
231,357,405	241,133,018					5
385,402,361	367,155,333					6
70,077	-923,459					7
70,747,118	71,678,968					8
10,873,443	453,060					9
55,045	55,045					10
						11
6,688,721	278,697					12
-293,623	31,942,337					13
197,728,627	198,164,185					14
21,013,707	39,109,116					15
8,798,827	15,398,957					16
838,754,779	1,152,367,603					17
608,242,675	960,800,421					18
						19
4,573,793	4,573,793					20
						21
500,880	53,143					22
447,680	393,324					23
						24
2,927,361,941	2,953,642,525					25
592,283,233	568,579,947					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		592,283,233	568,579,947		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,949,265	947,281		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,637,402	915,724		
33	Revenues From Nonutility Operations (417)		1,500	1,500		
34	(Less) Expenses of Nonutility Operations (417.1)		26,228	23,504		
35	Nonoperating Rental Income (418)		4,731	75,419		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		163,181	688,652		
38	Allowance for Other Funds Used During Construction (419.1)		35,214,865	30,789,970		
39	Miscellaneous Nonoperating Income (421)		100,695,289	98,193,348		
40	Gain on Disposition of Property (421.1)		715,765	1,196,300		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		137,080,966	130,953,242		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,219,096	615,446		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,277,953	1,998,442		
46	Life Insurance (426.2)					
47	Penalties (426.3)		-274,394	-2,492,000		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,147,962	2,883,694		
49	Other Deductions (426.5)		110,346,098	104,534,926		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		117,716,715	107,540,508		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	308,601	708,811		
53	Income Taxes-Federal (409.2)	262-263	-5,702,824	646,451		
54	Income Taxes-Other (409.2)	262-263	-985,426	199,519		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	722,200	268,954		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,718,654	2,844,230		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		6,617,182	5,946,124		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-13,993,285	-6,966,619		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		33,357,536	30,379,353		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		179,563,539	183,271,589		
63	Amort. of Debt Disc. and Expense (428)		3,574,447	2,955,733		
64	Amortization of Loss on Reaquired Debt (428.1)		1,441,956	1,435,287		
65	(Less) Amort. of Premium on Debt-Credit (429)		180,243	180,243		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		43,303	43,303		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		7,193,611	5,756,428		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		16,183,284	15,457,061		
70	Net Interest Charges (Total of lines 62 thru 69)		175,366,723	177,738,430		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		450,274,046	421,220,870		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		450,274,046	421,220,870		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,968,719,143	1,804,398,273
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		450,274,046	421,220,870
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-270,500,000	(256,900,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-270,500,000	(256,900,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,148,493,189	1,968,719,143
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,148,493,189	1,968,719,143
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	450,274,046	421,220,870
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	385,472,438	366,231,874
5	Amortization of UTL PLT; ACQ; ADJ; Prop Loss; Reg Study; Nuclear Fuel	165,899,295	119,652,444
6			
7	Deferred Fuel and Purchased Power	16,613,022	13,829,926
8	Deferred Income Taxes (Net)	225,814,123	164,038,909
9	Investment Tax Credit Adjustment (Net)	8,473,212	26,246,228
10	Net (Increase) Decrease in Receivables	-16,748,117	-56,202,973
11	Net (Increase) Decrease in Inventory	-21,427,295	7,127,553
12	Net (Increase) Decrease in Allowances Inventory	-2,517,423	-3,403,735
13	Net Increase (Decrease) in Payables and Accrued Expenses	-46,378,798	21,416,488
14	Net (Increase) Decrease in Other Regulatory Assets	-163,062,404	-74,694,494
15	Net Increase (Decrease) in Other Regulatory Liabilities	-27,989,767	66,971,000
16	(Less) Allowance for Other Funds Used During Construction	35,214,865	30,789,970
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
19	Other Current Assets	28,545,473	105,711,689
20	Other Current Liabilities	24,087,552	28,538,220
21	Other Long Term Assets/Liabilities Net	59,769,064	-97,657,825
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,051,609,556	1,078,236,204
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,024,915,891	-844,836,115
27	Gross Additions to Nuclear Fuel	-83,672,189	-76,296,155
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	16,183,284	15,457,061
31	Other (provide details in footnote):		
32	Contributions in Aid of Construction	46,546,059	20,325,000
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,078,225,305	-916,264,331
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Proceeds from Nuclear Decommissioning Trust and Sales (a)	478,813,436	356,194,667
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Investment in Nuclear Decommissioning Trust and Sales (a)	-496,062,379	-373,443,610
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	36,535,000	11,048,052
53	Other (provide details in footnote):		
54	Investments and Other Assets	-1,093,573	346,784
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,060,032,821	-922,118,438
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	842,414,500	606,126,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	842,414,500	606,126,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-402,150,000	-502,129,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-147,400,000	-5,725,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-266,900,000	-253,600,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	25,964,500	-155,328,000
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	17,541,235	789,766
87			
88	Cash and Cash Equivalents at Beginning of Period	4,515,054	3,725,288
89			
90	Cash and Cash Equivalents at End of period	22,056,289	4,515,054

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 19 Column: b

Risk Management	$	27,268,231
Notes Receivable		924,988
Prepaids		352,254
	$	28,545,473

Schedule Page: 120 Line No.: 19 Column: c

Prepaids	$	133,977,797
Risk Management		(28,266,108)
	$	105,711,689

Schedule Page: 120 Line No.: 20 Column: b

Transmission Termination Agreement	$	18,000,000
Accrued Taxes		11,715,223
Payroll Accrual		8,346,212
SCE Right of Way		6,593,895
Four Corners Take or Pay		4,601,788
Interest Accrued		3,463,494
Other		1,624,998
Customer Deposits		766,008
Palo Verde Sale Leaseback		(113,622)
Tolling Agreements		(1,814,786)
Exchange		(2,479,935)
Carbon Allowance		(2,644,370)
Risk Management		(3,063,764)
Employee Benefits		(6,514,419)
PVVIE Capital Lease		(14,393,170)
	$	24,087,552

Schedule Page: 120 Line No.: 20 Column: c

Interest Accrued	$	9,863,387
Accrued Taxes		9,787,678
Employee Benefits		9,502,694
Carbon Allowance		3,408,027
SCE Right of Way		2,279,271
Tolling Agreements		1,511,300
Exchange		1,484,640
Palo Verde Sale Leaseback		(4,634)
Risk Management		(75,000)
Other		(2,663,184)
Payroll Accrual		(2,761,795)
Customer Deposits		(3,794,164)
	$	28,538,220

Schedule Page: 120 Line No.: 21 Column: b

Post-Employment Benefits	$	114,608,409

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Risk Management		37,737,071
Nuclear Decommissioning Trust		17,248,943
Other		6,997,958
Carbon Allowances		5,189,847
Coal Reclamation		3,691,702
Transmission Debits		1,808,247
Software License Agreement		1,195,391
High Lonesome Wind Ranch Tax Credit		1,083,722
Information Systems Maintenance		682,660
Palo Verde Water Supply		421,224
Line of Credit		(101,516)
Superfund		(157,271)
Rouse Lease		(4,544,333)
Palo Verde Sale/Leaseback		(4,747,577)
Transmission Termination Agreement		(6,000,000)
Tolling Agreements		(6,721,746)
Customer Advances for Construction		(7,563,992)
Regulatory Asset Amortization		(8,377,665)
Depreciation Fund		(21,330,474)
Utility Plant		(27,245,454)
Deferred Fuel MTM		(44,106,082)
	$	59,769,064

Schedule Page: 120   Line No.: 21   Column: c

Depreciation Fund	$	(71,858,774)
Deferred Fuel MTM		(63,672,305)
Utility Plant		(37,590,372)
Post-Employment Benefits		(32,930,945)
Other		(19,674,727)
Coal Reclaimation		(9,161,037)
Tolling Agreements		(6,701,732)
Palo Verde Sale/Leaseback		(4,747,579)
Rouse Lease		(3,769,372)
Information Systems Maintenance		(2,495,797)
High Lonesome Wind Ranch Tax Credit		(1,083,722)
Superfund		(176,453)
Line of Credit		201,002
Palo Verde Water Supply		219,765
Transmission Termination Agreement		6,000,000
Customer Advances for Construction		10,095,245
Nuclear Decommissioning Trust		17,248,943
Regulatory Asset Amortization		30,234,588
OPEB		28,194,507
Risk Management		64,010,940
	$	(97,657,825)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 54 Column: b

Grant Street Land Purchase	$	(624,834)
Post-Employment Benefits		(480,267)
Other		11,528
	$	(1,093,573)

Schedule Page: 120 Line No.: 54 Column: c

Post-Employment Benefits	$	385,367
Other		(38,583)
	$	346,784

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

1. Other Comprehensive Basis of Accounting

The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. These differences include items, such as reporting certain derivatives in the income statement and balance sheet on a gross basis, reporting cost of removal in accumulated provision for depreciation, not separately reporting current accounts for deferred income taxes or long term debt, requiring deferred tax assets and liabilities to be shown gross on the balance sheet, classifying guidance on accounting for uncertainty in income tax liabilities on temporary differences as deferred income tax liabilities, including intangible assets in net utility plant, reclassification of certain risk management assets and liabilities, the non-consolidation of certain variable interest entities on the Comparative Balance Sheet, including prior year financial data for informational purposes only, including certain differences related to capital leases, not reporting debt issuance costs as reduction of long term debt, and certain other items.

APS' notes to financial statements have been combined with Pinnacle West Capital Corporation's financial statements and are prepared with generally accepted accounting principles, accordingly certain footnotes are not reflective of APS's financial statements contained herein.

2. Summary of Significant Accounting Policies

Nature of Operations

APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Regulatory Accounting

APS is regulated by the Arizona Corporation Commission and the Federal Energy Regulatory Commission. The accompanying financial statements reflect the rate-making policies of these commissions. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory environment and recent rate orders applicable to

APS or other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in Arizona and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

See Note 4 for additional information.

Electric Revenues

We derive electric revenues primarily from sales of electricity to our regulated Native Load customers. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated by applying an average revenue/kWh by customer class to the number of estimated kWhs delivered but not billed. Differences historically between the actual and estimated unbilled revenues are immaterial. We exclude sales taxes and franchise fees on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on APS's Comparative Statements of Income. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called a "book-out" and usually occurs for contracts that have the same terms (quantities and delivery points) and for which power does not flow. We report these book-outs on a gross basis, presenting both revenues and fuel and purchased power costs.

Some of our cost recovery mechanisms are alternative revenue programs. For alternative revenue programs that meet specified accounting criteria, we recognize revenues when the specific events permitting billing of the additional revenues have been completed.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents our best estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables, including accrued utility revenues. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment.

Property, Plant and Equipment

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

material and labor;
contractor costs;
capitalized leases;
construction overhead costs (where applicable); and
allowance for funds used during construction.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Liabilities associated with the retirement of tangible long-lived assets are recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense, and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 12.

APS records a regulatory liability for the difference between the amount that has been recovered in regulated rates and the amount calculated in accordance with guidance on accounting for asset retirement obligations. APS believes it can recover in regulated rates the costs calculated in accordance with this accounting guidance.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2015 were as follows:

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

Pursuant to an ACC order, we deferred operating costs in 2013 and 2014 related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners. See Note 4 for further discussion. These costs were deferred on the regulatory credits line and are now being amortized on the regulatory debits line of the Comparative Statements of Income.

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

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and an allowed return on the equity funds used for construction of regulated utility plant. Both the debt and equity components of AFUDC are non-cash amounts within the Comparative Statements of Income. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 8.02% for 2015, 8.47% for 2014, and 8.56% for 2013. APS compounds AFUDC semi-annually and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

Materials and Supplies

APS values materials, supplies and fossil fuel inventory using a weighted-average cost method. APS materials, supplies and fossil fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered.

Fair Value Measurements

We account for derivative instruments, investments held in our nuclear decommissioning trust, certain cash equivalents and plan assets held in our retirement and other benefit plans at fair value on a recurring basis. Due to the short-term nature of net accounts receivable, accounts payable, and short-term borrowings, the carrying values of these instruments approximate fair value. Fair value measurements may also be applied on a nonrecurring basis to other assets and liabilities in certain circumstances such as impairments. We also disclose fair value information for our long-term debt, which is carried at amortized cost (see Note 7).

Fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market which we can access for the asset or liability in an orderly transaction between willing market participants on the measurement date. Inputs to fair value may include observable and unobservable data. We maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

We determine fair market value using observable inputs such as actively-quoted prices for identical instruments when available. When actively quoted prices are not available for the identical instruments, we use other observable inputs, such as prices for similar instruments, other corroborative market information, or prices provided by other external sources. For options, long-term contracts and other contracts for which observable price data are not available, we use models and other valuation methods, which may incorporate unobservable inputs to determine fair market value.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods.

See Note 13 for additional information about fair value measurements.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and in interest rates. We manage risks associated with market volatility by utilizing various physical and financial instruments including futures, forwards, options and swaps. As part of our overall risk management program, we may use derivative instruments to hedge purchases and sales of electricity and fuels. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. We also enter into derivative instruments for economic hedging purposes. Contracts that have the same terms (quantities, delivery points and delivery periods) and for which power does not flow are netted, which reduces both revenues and fuel and purchased power expenses in our Comparative Statements of Income, but does not impact our financial condition, net income or cash flows.

We account for our derivative contracts in accordance with derivatives and hedging guidance, which requires all derivatives not qualifying for a scope exception to be measured at fair value on the balance sheet as either assets or liabilities. Transactions with counterparties that have master netting arrangements are reported gross on the balance sheet. See Note 15 for additional information about our derivative instruments.

Loss Contingencies and Environmental Liabilities

APS is involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses and environmental liabilities are recorded when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, APS records a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Retirement Plans and Other Postretirement Benefits

Pinnacle West sponsors a qualified defined benefit and account balance pension plan for the employees of Pinnacle West and its subsidiaries. Pinnacle West also sponsors another postretirement benefit plan for the employees of Pinnacle West and its subsidiaries that provides medical and life insurance benefits to retired employees. Pension and other postretirement benefit expense are determined by actuarial valuations, based on assumptions that are evaluated annually. See Note 8 for additional information on pension and other postretirement benefits.

Nuclear Fuel

APS amortizes nuclear fuel by using the unit-of-production method. The unit-of-production method is based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the interim storage and permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel and charged APS $0.001 per kWh of nuclear generation through May 2014, at which point the DOE suspended the fee. In accordance with a settlement agreement with the DOE in August 2014, we will now accrue a receivable for incurred claims and an offsetting regulatory liability through the settlement period ending December of 2016. See Note 11 for information on spent nuclear fuel disposal costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by guidance relating to accounting for income taxes. Pinnacle West Capital Corporation files the federal income tax return on a consolidated basis, and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each first-tier subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company.

Cash and Cash Equivalents

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

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

	Year ended December 31,	
	2015	**2014**
Cash paid (received) during the period for:		
Income taxes, net of refunds	$ 14,831	$ (86,054)
Interest, net of amounts capitalized	167,670	173,436
Significant non-cash investing and financing activities:		
Accrued capital expenditures	$ 83,798	$ 44,712
Dividends declared but not paid	69,400	65,800

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets, primarily software. The intangible assets are amortized over their finite useful lives. Amortization expense was $58 million in 2015, and $53 million in 2014. Estimated amortization expense on existing intangible assets over the next five years is $48 million in 2016, $36 million in 2017, $18 million in 2018, $9 million in 2019, and $3 million in 2020. At December 31, 2015, the weighted-average remaining amortization period for intangible assets was 5 years.

Investments

Our investments in the nuclear decommissioning trust fund are accounted for in accordance with guidance on accounting for certain investments in debt and equity securities. See Note 13 and Note 17 for more information on these investments.

Preferred Stock

At December 31, 2015, APS had 15,535,000 shares of various types of preferred stock authorized with $25, $50 and $100 par values, none of which was outstanding.

Subsequent Events

Management evaluates events or transactions that occur after the balance sheet date, but before the financial statements are issued or available to be issued for potential recognition or disclosures in the financial statements as required by GAAP. We have evaluated subsequent events for recognition in the financial statements through February 19, 2016, which is the date the financial statements, prepared in accordance with accounting principles generally accepted in the United States of America, were issued. Management updated such evaluation for disclosure purposes through March 17, 2016. The accompanying statements contain all adjustments and disclosures necessary for fair presentation.

3. New Accounting Standards

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

In February 2015, new consolidation accounting guidance was issued that amends many aspects of the guidance relating to the analysis and consolidation of variable interest entities. We do not expect the issuance of this guidance to have a material impact on our FERC financial statements.

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

4. Regulatory Matters

Retail Rate Case Filings with the Arizona Corporation Commission

Upcoming Rate Case Filing

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

Prior Rate Case Filing

On June 1, 2011, APS filed an application with the ACC for a net retail base rate increase of $95.5 million. APS requested that the increase become effective July 1, 2012. The request would have increased the average retail customer bill by approximately 6.6%. On January 6, 2012, APS and other parties to the general retail rate case entered into the 2012 Settlement Agreement detailing the terms upon which the parties agreed to settle the rate case. On May 15, 2012, the ACC approved the 2012 Settlement Agreement without material modifications.

Settlement Agreement

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

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

An authorized return on common equity of 10.0%;

A capital structure comprised of 46.1% debt and 53.9% common equity;

A test year ended December 31, 2010, adjusted to include plant that is in service as of March 31, 2012;

Deferral for future recovery or refund of property taxes above or below a specified 2010 test year level caused by changes to the Arizona property tax rate as follows:

Deferral of increases in property taxes of 25% in 2012, 50% in 2013 and 75% for 2014 and subsequent years if Arizona property tax rates increase; and

Deferral of 100% in all years if Arizona property tax rates decrease;

A procedure to allow APS to request rate adjustments prior to its next general rate case related to APS's acquisition of additional interests in Units 4 and 5 and the related closure of Units 1-3 of Four Corners (APS made its filing under this provision on December 30, 2013, see "Four Corners" below);

Implementation of a "Lost Fixed Cost Recovery" rate mechanism to support energy efficiency and distributed renewable generation;

Modifications to the Environmental Improvement Surcharge to allow for the recovery of carrying costs for capital expenditures associated with government-mandated environmental controls, subject to an existing cents per kWh cap on cost recovery that could produce up to approximately $5 million in revenues annually;

Modifications to the PSA, including the elimination of the 90/10 sharing provision;

A limitation on the use of the RES surcharge and the DSMAC to recoup capital expenditures not required under the terms of the 2009 Settlement Agreement;

Allowing a negative credit that existed in the PSA rate to continue until February 2013, rather than being reset on the anticipated July 1, 2012 rate effective date;

Modification of the TCA to streamline the process for future transmission-related rate changes; and

Implementation of various changes to rate schedules, including the adoption of an experimental "buy-through" rate that could allow certain large commercial and industrial customers to select alternative sources of generation to be supplied by APS.

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

Cost Recovery Mechanisms

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

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

In 2013, the ACC conducted a hearing to consider APS's proposal to establish compliance with distributed energy requirements by tracking and recording distributed energy, rather than acquiring and retiring renewable energy credits. On February 6, 2014, the ACC established a proceeding to modify the renewable energy rules to establish a process for compliance with the renewable energy requirement that is not based solely on the use of renewable energy credits. On September 9, 2014, the ACC authorized a rulemaking process to modify the RES rules. The proposed changes would permit the ACC to find that utilities have complied with the distributed energy requirement in light of all available information. The ACC adopted these changes on December 18, 2014. The revised rules went into effect on April 21, 2015.

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

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

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

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

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

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

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

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

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

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

PSA Mechanism and Balance. The PSA provides for the adjustment of retail rates to reflect variations in retail fuel and purchased power costs. The PSA is subject to specified parameters and procedures, including the following:

> APS records deferrals for recovery or refund to the extent actual retail fuel and purchased power costs vary from the Base Fuel Rate;
>
> An adjustment to the PSA rate is made annually each February 1 (unless otherwise approved by the ACC) and goes into effect automatically unless suspended by the ACC;
>
> The PSA uses a forward-looking estimate of fuel and purchased power costs to set the annual PSA rate, which is reconciled to actual costs experienced for each PSA Year (February 1 through

January 31) (see the following bullet point);

The PSA rate includes (a) a "Forward Component," under which APS recovers or refunds differences between expected fuel and purchased power costs for the upcoming calendar year and those embedded in the Base Fuel Rate; (b) a "Historical Component," under which differences between actual fuel and purchased power costs and those recovered through the combination of the Base Fuel Rate and the Forward Component are recovered during the next PSA Year; and (c) a "Transition Component," under which APS may seek mid-year PSA changes due to large variances between actual fuel and purchased power costs and the combination of the Base Fuel Rate and the Forward Component; and

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

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

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

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

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

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

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

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

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

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

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

Net Metering

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

In making its decision, the ACC determined that the current net metering program creates a cost shift, causing non-solar utility customers to pay higher rates to cover the costs of maintaining the electric grid. The ACC acknowledged that the $0.70 per kilowatt charge addresses only a portion of the cost shift.

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

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

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

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

Four Corners

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

As part of APS's acquisition of SCE's interest in Units 4 and 5, APS and SCE agreed, via a "Transmission Termination Agreement" that, upon closing of the acquisition, the companies would terminate an existing transmission agreement ("Transmission Agreement") between the parties that provides transmission capacity on a system (the "Arizona Transmission System") for SCE to transmit its portion of the output from Four Corners to California. APS previously submitted a request to FERC related to this termination, which resulted in a FERC order denying rate recovery of $40 million that APS agreed to pay SCE associated with the termination. APS and SCE negotiated an alternate arrangement under which SCE would assign its 1,555 MW capacity rights over the Arizona Transmission System to third-parties, including 300 MW to APS's marketing and trading group. However, this alternative arrangement was not approved by FERC. On December 22, 2015, APS and SCE agreed to terminate the Transmission Termination Agreement and allow for the Transmission Agreement to expire according to its terms, which includes settling obligations in accordance with the terms of the Transmission Agreement. APS has established a regulatory asset of $12 million at December 31, 2015 in connection with the expiration of the Transmission Agreement, which it expects to recover through its FERC-jurisdictional rates.

Cholla

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

Regulatory Assets and Liabilities

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

	December 31, 2015	December 31, 2014
Pension and other postretirement benefits (a)	$ 619,223	$ 485,037
Income taxes - AFUDC equity	139,207	123,209
Deferred fuel and purchased power — mark-to-market (Note 13)	141,549	97,442
Transmission vegetation management	4,543	13,629
Coal reclamation	6,503	6,921
Deferred compensation	34,751	34,162
Deferred fuel and purchased power (b) (c)	—	6,926
Tax expense of Medicare subsidy	13,683	15,284
Prior flow through of tax benefits	3,520	5,500
Income taxes — investment tax credit basis adjustment	50,228	47,916
Pension and other postretirement benefits deferral	—	4,238
Lost fixed cost recovery	45,507	37,612
Retired power plant costs	137,431	146,095
Four Corners cost deferral	70,271	77,253
Deferred property taxes	50,453	30,283
Mead - Phoenix Transmission Line CIAC	11,372	11,704
Other	5,933	3,874
Total regulatory assets (d)	$ 1,334,174	$ 1,147,085

(a) This asset represents the future recovery of pension benefit obligations through retail rates. If these costs are disallowed by the ACC, this regulatory asset would be charged to OCI and result in lower future revenues. See Note 8 for further discussion.

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

(c) Subject to a carrying charge.

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

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

	December 31, 2015	December 31, 2014
Asset retirement obligations	$ 277,554	$ 295,546
Renewable energy standard (a)	48,138	47,273
Income taxes - change in rates	76,553	75,844
Spent nuclear fuel	70,488	69,990
Deferred gains on utility property	8,063	10,000
Income taxes — deferred investment tax credit	100,779	96,232
Excess deferred taxes	3,520	5,500
Demand side management (a)	25,194	31,335
Other postretirement benefits	213,621	230,915
Four Corners coal reclamation	8,920	1,200
Sundance maintenance	13,678	12,069
Deferred fuel and purchased power	9,688	—
Other	23,328	23,263
Total regulatory liabilities	$ 879,524	$ 899,167

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

5. Income Taxes

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

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

In accordance with regulatory requirements, APS ITCs are deferred and are amortized over the life of the related property, with such amortization applied as a credit to reduce current income tax expense in the statement of income.

The components of APS's income tax expense are as follows (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Current:		
Federal	$ 15,311	$ 39,756
State	7,813	15,598
Total current	23,124	55,354
Deferred:		
Federal	199,681	166,426
State	23,217	16,620
Total deferred	222,898	183,046
Total income tax expense	$ 246,022	$ 238,400

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

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

	Year Ended December 31,	
	2015	2014
Federal income tax expense at 35% statutory rate	$ 243,640	$ 230,503
Increases (reductions) in tax expense resulting from:		
State income tax net of federal income tax benefit	20,433	21,148
Credits and favorable adjustments related to prior years resolved in current year	(1,710)	—
Medicare Subsidy Part-D	837	830
Allowance for equity funds used during construction (see Note 2)	(9,711)	(8,523)
Investment tax credit amortization	(5,527)	(4,928)
Other	(1,940)	(630)
Income tax expense	$ 246,022	$ 238,400

On February 17, 2011, Arizona enacted legislation (H.B. 2001) that included a four-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, APS has revised the tax rate applicable to reversing temporary items in Arizona. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2015, APS has recorded a regulatory liability of $75 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

On April 4, 2013, New Mexico enacted legislation (H.B. 641) that included a five-year phase-in of corporate income tax rate reductions beginning in 2014. As a result of these tax rate reductions, APS has revised the tax rate applicable to reversing temporary items in New Mexico. In accordance with accounting for regulated companies, the benefit of this rate reduction is substantially offset by a regulatory liability. As of December 31, 2015, APS has recorded a regulatory liability of $2 million, with a corresponding decrease in accumulated deferred income tax liabilities, to reflect the impact of this change in tax law.

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

	December 31,	
	2015	2014
DEFERRED TAX ASSETS		
Regulatory liabilities:		
Asset retirement obligation and removal costs	$ 107,885	$ 115,825
Unamortized investment tax credits	100,779	96,232
Other postretirement benefits	83,034	90,496
Other	61,868	61,604
Risk management activities	80,616	66,251
Pension liabilities	181,787	194,541
Renewable energy incentives	60,956	65,169
Other	176,016	161,379
Total deferred tax assets	852,941	851,497
DEFERRED TAX LIABILITIES		
Plant-related	(3,032,796)	(2,877,990)
Risk management activities	(20,744)	(20,917)
Other postretirement benefit assets	(70,986)	(58,495)
Regulatory assets:		
Allowance for equity funds used during construction	(54,110)	(48,286)
Deferred fuel and purchased power	—	(2,498)
Deferred fuel and purchased power — mark-to-market	(55,020)	(38,187)
Pension benefits	(240,692)	(191,747)
Retired power plant costs (see Note 4)	(53,420)	(57,255)
Other	(109,601)	(100,318)
Other	(4,984)	(5,484)
Total deferred tax liabilities	(3,642,353)	(3,401,777)
Deferred income taxes — net	$ (2,789,412)	$ (2,549,680)

6. Lines of Credit and Short-Term Borrowings

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

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

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

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

At December 31, 2015, APS had two credit facilities totaling $1 billion, including the $500 million credit facility that matures in September 2020 and a $500 million credit facility that matures in May 2019. APS may increase the amount of each facility up to a maximum of $700 million each, for a total of $1.4 billion, upon the satisfaction of certain conditions and with the consent of the lenders. Interest rates are based on APS’s senior unsecured debt credit ratings. These facilities are available to support APS’s $250 million commercial paper program, for bank borrowings or for issuances of letters of credit. At December 31, 2015, APS had no outstanding borrowings or letters of credit under its revolving credit facilities. See "Financial Assurances" in Note 11 for a discussion of APS's other outstanding letters of credit.

Debt Provisions

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

7. Long-Term Debt and Liquidity Matters

All of APS’s debt is unsecured. The following table presents the components of long-term debt on the Comparative Balance Sheets outstanding at December 31, 2015 and 2014 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2015	December 31, 2014
APS				
Pollution control bonds:				
Variable	2029-2038	(b)	$ 92,405	$ 156,405
Fixed	2024-2034	1.75%-5.75%	211,150	249,300
Total pollution control bonds			303,555	405,705
Other long-term debt	2016-2045	1.02%-8.75%	3,453,695	2,902,578
Unamortized discount			(10,374)	(9,206)
Unamortized premium			4,686	4,866
Total Long-Term Debt			$ 3,751,562	$ 3,303,943

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturities.
(b) The weighted-average rate for the variable rate pollution control bonds was 0.01%-0.24% at December 31, 2015 and 0.03%-0.27% at December 31, 2014.

The following table shows principal payments due on APS's total long-term debt (dollars in thousands):

Year	APS
2016	$ 357,580
2017	—
2018	82,000
2019	500,000
2020	250,000
Thereafter	2,567,670
Total	$ 3,757,250

Debt Fair Value

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

	As of December 31, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total	$ 3,694,971	$ 3,981,367	$ 3,265,143	$ 3,714,108

Credit Facilities and Debt Issuances

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

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

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

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

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

On November 17, 2015, APS redeemed at par and canceled all $38 million of the Navajo County, Arizona Pollution Control Corporation Revenue Refunding Bonds (Arizona Public Service Company Cholla Project), 2009 Series A.

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

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

See "Lines of Credit and Short-Term Borrowings" in Note 6 and "Financial Assurances" in Note 11 for discussion of APS's separate outstanding letters of credit.

Debt Provisions

APS's debt covenants related to its respective bank financing arrangements include maximum debt to capitalization ratios. APS complies with this covenant. For APS, this covenant requires that the ratio of debt to total capitalization not exceed 65%. At December 31, 2015, the ratio was approximately 46% for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants and could cross-default other debt. See further discussion of "cross-default" provisions below.

None of APS's financing agreements contain "rating triggers" that would result in an acceleration of the required interest and principal payments in the event of a rating downgrade. However, our bank credit agreements contain a pricing grid in which the interest rates we pay for borrowings thereunder are determined by our current credit ratings.

All of 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. APS does not have a material adverse change restriction for credit facility borrowings.

An existing ACC order requires APS to maintain a common equity ratio of at least 40%. As defined in the ACC order, the common equity ratio is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. At December 31, 2015, APS was in compliance with this common equity ratio requirement. Its total shareholder equity was approximately $4.7 billion, and total capitalization was approximately $8.6 billion. APS would be prohibited from paying dividends if the payment would reduce its total shareholder equity below approximately $3.4 billion, assuming APS's total capitalization remains the same.

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On February 6, 2013, the ACC issued a financing order in which, subject to specified parameters and procedures, it approved an increase in APS's long-term debt authorization from $4.2 billion to $5.1 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs, and authorized APS to enter into derivative financial instruments for the purpose of managing interest rate risk associated with its long- and short-term debt. This financing order is set to expire on December 31, 2017. See Note 6 for additional short-term debt provisions.

8. Retirement Plans and Other Postretirement Benefits

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

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

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

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

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

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

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

	Pension		Other Benefits	
	2015	2014	2015	2014
Service cost-benefits earned during the period	$ 59,627	$ 53,080	$ 16,827	$ 18,139
Interest cost on benefit obligation	123,983	129,194	28,102	41,243
Expected return on plan assets	(179,231)	(158,998)	(36,855)	(46,400)
Amortization of:				
Prior service cost (credit)	594	869	(37,968)	(9,626)
Net actuarial loss	31,056	10,963	4,881	1,175
Net periodic benefit cost	$ 36,029	$ 35,108	$ (25,013)	$ 4,531
Portion of cost charged to expense	$ 20,036	$ 21,985	$ (10,391)	$ 6,000

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Plan Assets

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

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

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

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

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

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

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

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

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

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

The plans' trustee provides valuation of our plan assets by using pricing services that utilize methodologies described to determine fair market value. We have internal control procedures to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes.

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) _ A Resubmission	03/17/2016	2015/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (b)	Balance at December 31, 2015
Pension Plan:					
Assets:					
Cash and cash equivalents	$ 1,893	$ —	$ —	$ —	$ 1,893
Fixed income securities:					
Corporate	—	1,108,736	—	—	1,108,736
U.S. Treasury	274,778	—	—	—	274,778
Other (a)	—	113,008	—	—	113,008
Equities:					
U.S. companies	233,021	—	—	—	233,021
International companies	14,680	—	—	—	14,680
Common and collective trusts:					
U.S. equities	—	130,097	—	—	130,097
International equities	—	185,892	—	—	185,892
Real estate	—	150,359	—	—	150,359
Partnerships	—	127,840	42,097	—	169,937
Mutual funds - International equities	116,307	—	—	—	116,307
Short-term investments and other	—	29,599	—	14,467	44,066
Total Pension Plan	$ 640,679	$ 1,845,531	$ 42,097	$ 14,467	$ 2,542,774
Other Benefits:					
Assets:					
Cash and cash equivalents	$ 240	$ —	$ —	$ —	$ 240
Fixed income securities:					
Corporate	—	217,026	—	—	217,026
U.S. Treasury	131,435	—	—	—	131,435
Other (a)	—	31,106	—	—	31,106
Equities:					
U.S. companies	253,193	—	—	—	253,193
International companies	12,390	—	—	—	12,390
Common and collective trusts:					
U.S. equities	—	81,516	—	—	81,516
International equities	—	28,539	—	—	28,539
Real estate	—	13,512	—	—	13,512
Mutual funds - International equities	52,568	—	—	—	52,568
Short-term investments and other	5,065	3,331	—	3,096	11,492
Total Other Benefits	$ 454,891	$ 375,030	$ —	$ 3,096	$ 833,017

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

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

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

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

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

Contributions

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

Estimated Future Benefit Payments

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

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

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

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and its subsidiaries. In 2015, costs related to APS's employees represented 99% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account, the Company's matching contributions and earnings or losses on their investments. Under this plan, the Company matches a percentage of the participants' contributions in cash which is then invested in the same investment mix as participants elect to invest their own future contributions. Pinnacle West recorded expenses for this plan of approximately $9 million for 2015, and $9 million for 2014.

9. Leases

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

APS's lease expense was $59 million in 2015, and $60 million in 2014.

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

Year	APS
2016	$ 31,797
2017	31,317
2018	29,880
2019	28,961
2020	27,680
Thereafter	290,101
Total future lease commitments	$ 439,736

In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back interests in Palo Verde Unit 2 and related common facilities.

10. Jointly-Owned Facilities

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

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

(a) See Note 16.
(b) Weighted-average of interests.
(c) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.

11. Commitments and Contingencies

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

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

DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment of $57.4 million by DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007 through June 30, 2011. APS's share of this amount is $16.7 million. Amounts recovered in the lawsuit and settlement were recorded as adjustments to a regulatory liability and had no impact on the amount of current reported net income. In addition, the settlement agreement provides APS with a method for submitting claims and getting recovery for costs incurred through 2016.

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

Nuclear Insurance

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

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

Fuel and Purchased Power Commitments and Purchase Obligations

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

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

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

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

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

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

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

Renewable Energy Credits

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

Coal Mine Reclamation Obligations

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

$19 million in 2019; $20 million in 2020; and $262 million thereafter. Any amendments to current coal supply agreements may change the timing of the contribution. Portions of these funds will be held in an escrow account and distributed to certain coal providers under the terms of the applicable coal supply agreements.

Superfund-Related Matters

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

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

Southwest Power Outage

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

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

Clean Air Act Citizen Lawsuit

On October 4, 2011, Earthjustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against APS and the other Four Corners participants alleging violations of the NSR provisions of the Clean Air Act. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the Clean Air Act's NSPS program. The case was held in abeyance while APS negotiated a settlement with DOJ and environmental plaintiffs. In March 2015, the parties agreed in principle to settle the case, and on June 24, 2015, DOJ lodged the proposed consent decree with the United States District Court for the District of New Mexico. On August 17, 2015, the consent decree was entered by the district court.

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

Environmental Matters

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

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

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

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

Cholla. APS believes that EPA's final rule as it applies to Cholla, which would require installation of SCR controls with a cost to APS of approximately $100 million (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015), is unsupported and that EPA had no basis for disapproving Arizona's SIP and promulgating a FIP that is inconsistent with the state's considered BART determinations under the regional haze program. Accordingly, on February 1, 2013, APS filed a Petition for Review of the final BART rule in the United States Court of Appeals for the Ninth Circuit. Briefing in the case was completed in February 2014.

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

Mercury and Air Toxic Standards ("MATS"). In 2011, EPA issued rules establishing maximum achievable control technology standards to regulate emissions of mercury and other hazardous air pollutants from fossil-fired plants. APS estimates that the cost for the remaining equipment necessary to meet these standards is approximately $8 million for Cholla (excludes costs related to Cholla Unit 2 which was closed on October 1, 2015). No additional equipment is needed for Four Corners Units 4 and 5 to comply with these rules. SRP, the operating agent for the Navajo Plant, estimates that APS's share of costs for equipment necessary to comply with the rules is approximately $1 million. The United States Supreme Court's recent decision in *Michigan vs. EPA* reversed and remanded the MATS proceeding back to the DC Circuit Court. The Circuit Court then remanded the MATS rule back to EPA to address rulemaking deficiencies identified by the Supreme Court. Further EPA action on the MATS rule is pending. This proceeding does not materially impact APS. Regardless of how EPA addresses the deficiencies in the MATS rulemaking, the Arizona State Mercury Rule, the stringency of which is roughly equivalent to that of MATS, would still apply to Cholla.

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

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

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

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

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

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

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

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

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

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

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

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

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

Notice of Intent to Sue Related to Four Corners

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

New Mexico Tax Matter

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

Financial Assurances

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

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

12. Asset Retirement Obligations

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

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

In 2015, a revision to the estimated cash flows for the decommissioning study was completed for the Four Corners coal-fired plant, which resulted in an increase to the ARO in the amount of $24 million. Also in 2015, Four Corners spent $32 million in actual decommissioning costs. In addition, APS recognized an ARO for Cholla as a result of new CCR environmental rules that were published in the Federal Register in the second quarter of 2015. See Note 11 for additional information related to the CCR environmental rules. This resulted in an increase to the ARO in the amount of $39 million, an increase in plant in service of $23 million and a reduction of the regulatory liability of $16 million. Finally, in 2015 there was a revision in estimated cash flows for the Cholla decommissioning, which resulted in a decrease of the ARO in the amount of $3 million.

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

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

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

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

In accordance with regulatory accounting, APS accrues removal costs for its regulated utility assets, even if there is no legal obligation for removal. See detail of regulatory liabilities in Note 4.

13. Fair Value Measurements

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

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

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

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

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Thus, a valuation may be classified in Level 3 even though the valuation may include significant inputs that are readily observable. We maximize the use of observable inputs and minimize the use of unobservable inputs. We rely primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities. If market data is not readily available, inputs may reflect our own assumptions about the inputs market participants would use. Our assessment of the inputs and the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities as well as their placement within the fair value hierarchy levels. We assess whether a market is active by obtaining observable broker quotes, reviewing actual market activity, and assessing the volume of transactions. We consider broker quotes observable inputs when the quote is binding on the broker, we can validate the quote with market activity, or we can determine that the inputs the broker used to arrive at the quoted price are observable.

Recurring Fair Value Measurements

We apply recurring fair value measurements to certain cash equivalents, derivative instruments, investments held in our nuclear decommissioning trust and plan assets held in our retirement and other benefit plans. See Note 8 for the fair value discussion of plan assets held in our retirement and other benefit plans.

Cash Equivalents

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

Risk Management Activities — Derivative Instruments

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

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

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

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

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

Investments Held in our Nuclear Decommissioning Trust

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

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

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

We price securities using information provided by our trustee for our nuclear decommissioning trust assets. Our trustee uses pricing services that utilize the valuation methodologies described to determine fair market value. We have internal control procedures designed to ensure this information is consistent with fair value accounting guidance. These procedures include assessing valuations using an independent pricing source, verifying that pricing can be supported by actual recent market transactions, assessing hierarchy classifications, comparing investment returns with benchmarks, and obtaining and reviewing independent audit reports on the trustee's internal operating controls and valuation processes. See Note 17 for additional discussion about our nuclear decommissioning trust.

Fair Value Tables

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

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (a) (Level 3)	Other	Balance at December 31, 2015
Assets					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ 22,992	$ 30,364	$ 12	$ 53,368
Nuclear decommissioning trust:					
U.S. commingled equity funds	—	314,957	—	—	314,957
Fixed income securities:					
Cash and cash equivalent funds	12,260	—	—	(335)	11,925
U.S. Treasury	117,245	—	—	—	117,245
Corporate debt	—	96,243	—	—	96,243
Mortgage-backed securities	—	99,065	—	—	99,065
Municipal bonds	—	72,206	—	—	72,206
Other	—	23,555	—	—	23,555
Subtotal nuclear decommissioning trust	129,505	606,026	—	(335)	735,196
Total	$ 129,505	$ 629,018	$ 30,364	$ (323)	$ 788,564
Liabilities					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ (144,044)	$ (63,343)	$ (12)	$ (207,399)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.

The following table presents the fair value at December 31, 2014 of our assets and liabilities that are measured at fair value on a recurring basis (dollars in 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, 2014
Assets					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ 20,769	$ 32,598	$ 6	$ 53,373
Nuclear decommissioning trust:					
U.S. commingled equity funds	—	309,620	—	—	309,620
Fixed income securities:					
U.S. Treasury	118,843	—	—	—	118,843
Cash and cash equivalent funds	—	11,453	—	(7,245)	4,208
Corporate debt	—	109,379	—	—	109,379
Mortgage-backed securities	—	88,465	—	—	88,465
Municipal bonds	—	69,139	—	—	69,139
Other	—	14,212	—	—	14,212
Subtotal nuclear decommissioning trust	118,843	602,268	—	(7,245)	713,866
Total	$ 118,843	$ 623,037	$ 32,598	$ (7,239)	$ 767,239
Liabilities					
Risk management activities — derivative instruments:					
Commodity contracts	$ —	$ (95,061)	$ (73,984)	$ (7)	$ (169,052)

(a) Primarily consists of heat rate options and other long-dated electricity contracts.

Fair Value Measurements Classified as Level 3

The significant unobservable inputs used in the fair value measurement of our energy derivative contracts include broker quotes that cannot be validated as an observable input primarily due to the long-term nature of the quote and option model inputs. Significant changes in these inputs in isolation would result in significantly higher or lower fair value measurements. Changes in our derivative contract fair values, including changes relating to unobservable inputs, typically will not impact net income due to regulatory accounting treatment (see Note 4).

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

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

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

The following tables provide information regarding our significant unobservable inputs used to value our risk management derivative Level 3 instruments at December 31, 2015 and December 31, 2014:

	December 31, 2015 Fair Value (millions)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ 24,543	$ 54,679	Discounted cash flows	Electricity forward price (per MWh)	$15.92 - $40.73	$ 26.86
Option Contracts (b)	—	5,628	Option model	Electricity forward price (per MWh)	$23.87 - $44.13	$ 33.91
				Electricity price volatilities	40% - 59%	52%
				Natural gas price volatilities	32% - 40%	35%
Natural Gas:						
Forward Contracts (a)	5,821	3,036	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.18 - $3.14	$ 2.61
Total	$30,364	$ 63,343				

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

	December 31, 2014 Fair Value (millions)					
Commodity Contracts	**Assets**	**Liabilities**	**Valuation Technique**	**Significant Unobservable Input**	**Range**	**Weighted-Average**
Electricity:						
Forward Contracts (a)	$ 29,471	$ 55,894	Discounted cash flows	Electricity forward price (per MWh)	$19.51 - $56.72	$ 35.27
Option Contracts (b)	—	15,035	Option model	Electricity forward price (per MWh)	$32.14 - $66.09	$ 45.83
				Natural gas forward price (per MMBtu)	$3.18 - $3.29	$ 3.25
				Electricity price volatilities	23% - 63%	41%
				Natural gas price volatilities	23% - 41%	31%
Natural Gas:						
Forward Contracts (a)	3,127	3,055	Discounted cash flows	Natural gas forward price (per MMBtu)	$2.98 - $4.13	$ 3.45
Total	$ 32,598	$ 73,984				

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

The following table shows the changes in fair value for our risk management activities' assets and liabilities that are measured at fair value on a recurring basis using Level 3 inputs for the years ended December 31, 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
Commodity Contracts	**2015**	**2014**
Net derivative balance at beginning of period	$ (41,386)	$ (49,165)
Total net gains (losses) realized/unrealized:		
Included in earnings	—	102
Included in OCI	(452)	(239)
Deferred as a regulatory asset or liability	(4,009)	(482)
Settlements	14,809	12,080
Transfers into Level 3 from Level 2	(6,256)	(2,090)
Transfers from Level 3 into Level 2	4,315	(1,592)
Net derivative balance at end of period	$ (32,979)	$ (41,386)
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 7 for our long-term debt fair values.

14. Stock-Based Compensation

Pinnacle West has incentive compensation plans under which stock-based compensation is granted to officers, key-employees, and non-officer members of the Board of Directors. Awards granted under the 2012 Long-Term Incentive Plan ("2012 Plan") may be in the form of stock grants, restricted stock units, stock units, performance shares, restricted stock, dividend equivalents, performance share units, performance cash, incentive and non-qualified stock options, and stock appreciation rights. The 2012 Plan authorizes up to 4.6 million common shares to be available for grant. As of December 31, 2015, 2.8 million common shares were available for issuance under the 2012 Plan. During 2015, 2014, and 2013, the Company has granted awards in the form of restricted stock units, stock units, stock grants, and performance shares. The Company has not granted stock options since 2004 and has no stock options outstanding. Awards granted from 2007 to 2011 were issued under the 2007 Long-Term Incentive Plan ("2007 Plan"), and no new awards may be granted under the 2007 Plan.

Stock-Based Compensation Expense and Activity

Compensation cost included in net income for stock-based compensation plans was $19 million in 2015, and $33 million in 2014. The compensation cost capitalized is immaterial for all years. Income tax benefits related to stock-based compensation arrangements were $7 million in 2015, and $13 million in 2014.

As of December 31, 2015, there were approximately $14 million of unrecognized compensation costs related to nonvested stock-based compensation arrangements. These costs are expected to be recognized over a weighted-average period of 2 years. The total fair value of shares vested was $21 million in 2015, and $20 million in 2014.

The following table is a summary of awards granted and the weighted-average fair value for the three years ended 2015, and 2014.

	Restricted Stock Units, Stock Grants, and Stock Units (a)		Performance Shares (b)	
	2015	2014	2015	2014
Units granted	152,651	179,291	151,430	166,244
Weighted-average grant date fair value	$ 64.12	$ 54.89	$ 64.97	$ 54.86

(a) Units granted includes awards that will be cash settled of 45,104 in 2015, and 49,018 in 2014.

(b) Reflects the target payout level.

The following table is a summary of the status of non-vested awards as of December 31, 2015 and changes during the year.

	Restricted Stock Units, Stock Grants, and Stock Units		Performance Shares	
	Shares	Weighted-Average Grant Date Fair Value	Shares (b)	Weighted-Average Grant Date Fair Value
Nonvested at January 1, 2015	480,933 (a)	$ 51.27	324,230	$ 54.92
Granted	152,651	64.12	151,430	64.97
Change in performance factor	—	—	40,496	54.98
Vested	(198,424)	49.20	(202,480)	54.98
Forfeited	(6,873)	56.78	(7,844)	57.89
Nonvested at December 31, 2015	428,287	56.69	305,832	59.78
Vested Awards Outstanding at December 31, 2015	106,712		202,480	

(a) Includes 127,634 of awards that will be cash settled and 353,299 of awards that will be settled in shares.

(b) Nonvested performance shares are reflected at target payout level. The increase or decrease in the number of shares from the target level to the estimated actual payout level is included in the increase for performance factor amounts in the year the award vests.

Share-based liabilities paid relating to restricted stock unit awards was $10 million, and $9 million in 2015, and 2014, respectively. This includes cash used to settle restricted stock units of $3 million, and $3 million in 2015, and 2014, respectively. Share-based liabilities paid relating to performance share awards was $16 million, and $12 million in 2015, and 2014, respectively.

Restricted Stock Units, Stock Grants, and Stock Units

Restricted stock units have been granted to officers and key employees. Restricted stock units typically vest and settle in equal annual installments over a 4-year period after the grant date. Vesting is typically dependent upon continuous service during the vesting period; however, awards granted to retirement-eligible employees will vest upon the employee's retirement. Awardees elect to receive payment in either 100% stock, or 50% in cash and 50%

in stock. Restricted stock unit awards typically include a dividend equivalent feature. This feature allows each award to accrue dividend rights, equal to the amount of dividends that they would have received had they directly owned stock, equal to the number of vested restricted stock units from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited the employee is not entitled to the dividends on those shares.

In December 2012, a retention award of 50,617 restricted stock units was granted to the Chairman of the Board, President, and Chief Executive Officer of Pinnacle West. This award will vest and will be paid in shares of common stock on December 31, 2016, provided that he remains employed with the Company until the vesting date. The award can be increased up to an additional 33,745 restricted stock units payable in stock if certain performance requirements are met.

Restricted stock unit awards are accounted for as liability awards, with compensation cost initially calculated on the date of grant using the Company's closing stock price, and remeasured at each balance sheet date.

Stock grants are issued to non-officer members of the Board of Directors. They may elect to receive the stock grant, or to defer receipt until a later date and receive stock units in lieu of the stock grant. The members of the Board of Directors who elect to defer may elect to receive payment in either 100% stock, or 50% in cash and 50% in stock. The stock units accrue dividend rights, equal to the amount of dividends the Directors would have received had they directly owned stock equal to the number of vested restricted stock units or stock units from the date of grant to the date of payment plus interest compounded quarterly. The dividends and interest are paid, based on the Director's election, in either stock, or 50% in cash and 50% in stock.

Performance Share Awards

Performance share awards have been granted to officers and key employees. Performance share awards contain two performance element criteria that affect the number of shares received after the end of a three-year performance period if performance criteria conditions are met. The performance share grant criteria is based 50% upon the percentile ranking of Pinnacle West's total shareholder return at the end of the three-year performance period, as compared with the total shareholder return of all relevant companies in a specified utility index and the other 50% is based upon six non-financial separate performance metrics. The exact number of shares issued will vary from 0% to 200% of the target award. Shares received include dividend rights paid in stock equal to the amount of dividends that they would have received had they directly owned stock, equal to the number of vested performance shares from the date of grant to the date of payment plus interest compounded quarterly. If the award is forfeited or if the performance criteria are not achieved the employee is not entitled to the dividends on those shares.

Performance share awards are accounted for as liability awards, with compensation cost initially calculated on the date of grant using the Company's closing stock price, and remeasured at each balance sheet date. Management evaluates the probability of meeting the performance criteria at each balance sheet date. If performance criteria are not achieved, no compensation cost is recognized and any previously recognized compensation cost is reversed.

15. 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 Comparative Statements of Income, but does not impact our financial condition, net income or cash flows.

On June 1, 2012, we elected to discontinue cash flow hedge accounting treatment for the significant majority of our contracts that had previously been designated as cash flow hedges. This discontinuation is due to changes in PSA recovery (see Note 4), which now allows for 100% deferral of the unrealized gains and losses relating to these contracts. For those contracts that were de-designated, all changes in fair value after May 31, 2012 are no longer recorded through OCI, but are deferred through the PSA. The amounts previously recorded in accumulated OCI relating to these instruments will remain in accumulated OCI, and will transfer to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if we determine it is probable that the forecasted transaction will not occur. Cash flow hedge accounting treatment will continue for a limited number of contracts that are not subject to PSA recovery.

Our derivative instruments, excluding those qualifying for a scope exception, are recorded on the balance sheet as an asset or liability and are measured at fair value. See Note 13 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 4). Gains and losses from derivatives in the following tables represent the amounts reflected in income before the effect of PSA deferrals.

As of December 31, 2015, we had the following outstanding gross notional volume of derivatives, which represent both purchases and sales (does not reflect net position):

Commodity	Quantity	
Power	2,487	GWh
Gas	182	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 years ended December 31, 2015, and 2014 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2015	Year Ended December 31, 2014
Loss recognized in OCI on derivative instruments (effective portion)	OCI — derivative instruments	$ (615)	$ (372)
Loss reclassified from accumulated OCI into income (effective portion realized) (a)	Fuel and purchased power (b)	(5,988)	(21,415)

(a) During the years ended December 31, 2015, and 2014, 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 $4 million before income taxes will be reclassified from accumulated OCI as an offset to the effect of market price changes for the related hedged transactions. In accordance with the PSA, most of these amounts will be recorded as either a regulatory asset or liability and have no immediate effect on earnings.

The following table provides information about gains and losses from derivative instruments not designated as accounting hedging instruments during the years ended December 31, 2015 and 2014 (dollars in thousands):

Commodity Contracts	Financial Statement Location	Year Ended December 31, 2015	Year Ended December 31, 2014
Net gain recognized in income	Operating revenues	$ 574	$ 324
Net loss recognized in income	Fuel and purchased power (a)	(108,973)	(66,367)
Total		$(108,399)	$ (66,043)

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

Derivative Instruments in the Comparative 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 gross on the Comparative Balance Sheets. Transactions that do not allow for offsetting of positive and negative positions are also reported gross on the Comparative Balance Sheets.

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

The significant majority of our derivative instruments are not currently designated as hedging instruments. The Comparative Balance Sheets as of December 31, 2015 and December 31, 2014, include gross liabilities of $3 million and $4 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 potential impacts of offsetting relating to transactions executed under master netting arrangements. While certain amounts may be eligible for offsetting, under master netting arrangements, for FERC reporting purposes we do not offset on the balance sheet. These amounts relate to commodity contracts and are located in the assets and liabilities from risk management activities lines of our Comparative Balance Sheets.

As of December 31, 2015: **(dollars in thousands)**	**Gross Recognized Derivatives (a)**	**Eligible for Offsetting**		**Net Derivatives After Impacts of Offsetting**
		Derivatives	**Cash Collateral (b)**	
Current Assets	$ 37,396	$ (22,163)	$ —	$ 15,233
Investments and Other Assets	15,960	(3,854)	—	12,106
Total Assets	53,356	(26,017)	—	27,339
Current Liabilities	(113,560)	22,163	18,060	(73,337)
Deferred Credits and Other	(93,827)	3,854	—	(89,973)
Total Liabilities	(207,387)	26,017	18,060	(163,310)
Total	$ (154,031)	$ —	$ 18,060	$ (135,971)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.
(b) We had total cash collateral and margin provided to counterparties of $18,060; this amount is reflected in miscellaneous current and deferred credits. We had total cash collateral received from counterparties of $4,379 and cash margin provided to counterparties of $672; this amount is reflected in miscellaneous current and accrued liabilities. Certain cash collateral is not eligible for offsetting as it does not relate to recognized derivatives.

As of December 31, 2014: **(dollars in thousands)**	**Gross Recognized Derivatives (a)**	**Eligible for Offsetting**		**Net Derivatives After Impacts of Offsetting**
		Derivatives	**Cash Collateral (b)**	
Current Assets	$ 28,562	$ (15,127)	$ —	$ 13,435
Investments and Other Assets	24,810	(7,190)	—	17,620
Total Assets	53,372	(22,317)	—	31,055
Current Liabilities	(86,062)	15,127	18,702	(52,233)
Deferred Credits and Other	(82,990)	7,190	25,198	(50,602)
Total Liabilities	(169,052)	22,317	43,900	(102,835)
Total	$ (115,680)	$ —	$ 43,900	$ (71,780)

(a) All of our gross recognized derivative instruments were subject to master netting arrangements.

(b) We had total cash collateral and margin provided to counterparties of $43,900; this amount is reflected in miscellaneous current and deferred credits. We had total cash collateral received from counterparties of $7,443 and cash margin provided to counterparties of $350; this amount is reflected in miscellaneous current and accrued liabilities. Certain cash collateral is not eligible for offsetting as it does not relate to recognized derivatives.

Credit Risk and Credit Related Contingent Features

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management contracts with many counterparties, including one counterparty for which our exposure represents approximately 87% of APS's $28 million of risk management assets as of December 31, 2015. This exposure relates to a long-term traditional wholesale contract with a counterparty that has a high credit quality. Our risk management process assesses and monitors the financial exposure of all counterparties. 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 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 December 31, 2015 (dollars in thousands):

	December 31, 2015
Aggregate fair value of derivative instruments in a liability position	$ 207,387
Cash collateral posted	18,060
Additional cash collateral in the event credit-risk related contingent features were fully triggered (a)	112,301

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

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

16. 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. The original lease was scheduled to end on December 31, 2015; however, the lease agreements include fixed rate renewal options which APS exercised on July 7, 2014. As a result, 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 for the period 2016 through 2023, and about $16 million annually for the period 2024 through 2033. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

For regulatory reporting purposes, APS accounts for the lease renewal as a capital lease on the balance sheet and an operating lease for income statement and cash flow statement purposes.

APS is exposed to losses relating to these VIEs upon the occurrence of certain events that APS does not consider 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 could 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 extension period, APS may be required to pay the noncontrolling equity participants approximately $288 million beginning in 2016, and up to $465 million over the lease extension term.

17. 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 Comparative Balance Sheets. See Note 13 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 December 31, 2015 and December 31, 2014 (dollars in thousands):

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2015			
Equity securities	$ 314,957	$ 157,098	$ (115)
Fixed income securities	420,574	11,955	(2,645)
Net payables (a)	(335)	—	—
Total	$ 735,196	$ 169,053	$ (2,760)

	Fair Value	Total Unrealized Gains	Total Unrealized Losses
December 31, 2014			
Equity securities	$ 309,620	$ 159,274	$ (15)
Fixed income securities	411,491	17,260	(1,073)
Net payables (a)	(7,245)	—	—
Total	$ 713,866	$ 176,534	$ (1,088)

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

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

	Year Ended December 31, 2015	2014
Realized gains	$ 5,189	$ 4,725
Realized losses	(6,225)	(4,525)
Proceeds from the sale of securities (a)	478,813	356,195

(a) Proceeds are reinvested in the trust.

The fair value of fixed income securities, summarized by contractual maturities, at December 31, 2015 is as follows (dollars in thousands):

	Fair Value
Less than one year	$ 14,001
1 year – 5 years	117,356
5 years – 10 years	114,769
Greater than 10 years	174,448
Total	$ 420,574

18. Changes in Accumulated Other Comprehensive Loss

The following table shows the changes in APS's accumulated other comprehensive loss, including reclassification adjustments, net of tax, by component for the years ended December 31, 2015 and 2014 (dollars in thousands):

	Year Ended December 31,	
	2015	2014
Balance at beginning of period	$ (48,333)	$ (53,372)
Derivative Instruments		
OCI (loss) before reclassifications	(957)	(809)
Amounts reclassified from accumulated other comprehensive loss (a)	4,187	13,483
Net current period OCI (loss)	3,230	12,674
Pension and Other Postretirement Benefits		
OCI (loss) before reclassifications	14,726	(10,415)
Amounts reclassified from accumulated other comprehensive loss (b)	3,280	2,780
Net current period OCI (loss)	18,006	(7,635)
Balance at end of period	$ (27,097)	$ (48,333)

(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 15.

(b) These amounts primarily represent amortization of actuarial loss, and are included in the computation of net periodic pension cost. See Note 8.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(30,313,461)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,780,792
3	Preceding Quarter/Year to Date Changes in Fair Value				(10,414,982)
4	Total (lines 2 and 3)				(7,634,190)
5	Balance of Account 219 at End of Preceding Quarter/Year				(37,947,651)
6	Balance of Account 219 at Beginning of Current Year				(37,947,651)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				3,279,529
8	Current Quarter/Year to Date Changes in Fair Value				14,726,301
9	Total (lines 7 and 8)				18,005,830
10	Balance of Account 219 at End of Current Quarter/Year				(19,941,821)

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1		(23,058,959)	(53,372,420)		
2		13,483,153	16,263,945		
3		(809,174)	(11,224,156)		
4		12,673,979	5,039,789	421,220,870	426,260,659
5		(10,384,980)	(48,332,631)		
6		(10,384,980)	(48,332,631)		
7		4,187,494	7,467,023		
8		(957,776)	13,768,525		
9		3,229,718	21,235,548	450,274,046	471,509,594
10		(7,155,262)	(27,097,083)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	16,119,467,895	16,119,467,895
4	Property Under Capital Leases	193,312,890	193,312,890
5	Plant Purchased or Sold		
6	Completed Construction not Classified	460,983,004	460,983,004
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	16,773,763,789	16,773,763,789
9	Leased to Others		
10	Held for Future Use	51,471,935	51,471,935
11	Construction Work in Progress	713,287,335	713,287,335
12	Acquisition Adjustments	255,525,921	255,525,921
13	Total Utility Plant (8 thru 12)	17,794,048,980	17,794,048,980
14	Accum Prov for Depr, Amort, & Depl	6,402,411,202	6,402,411,202
15	Net Utility Plant (13 less 14)	11,391,637,778	11,391,637,778
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,678,404,960	5,678,404,960
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	712,679,738	712,679,738
22	Total In Service (18 thru 21)	6,391,084,698	6,391,084,698
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	11,326,504	11,326,504
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,402,411,202	6,402,411,202

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	15,977,379	36,095,177
3	Nuclear Materials	66,073,042	39,673,667
4	Allowance for Funds Used during Construction	9,170,405	6,100,955
5	(Other Overhead Construction Costs, provide details in footnote)	-155,306	1,801,051
6	SUBTOTAL (Total 2 thru 5)	91,065,520	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		75,276,604
9	In Reactor (120.3)	268,754,495	75,178,760
10	SUBTOTAL (Total 8 & 9)	268,754,495	
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	143,553,701	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	216,266,314	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	34,454,952	17,617,604	2
	31,856,733	73,889,976	3
	7,083,060	8,188,300	4
	1,784,015	-138,270	5
		99,557,610	6
			7
	75,275,759	845	8
	74,567,662	269,365,593	9
		269,366,438	10
			11
			12
-77,241,505	74,567,662	146,227,544	13
		222,696,504	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 202 Line No.: 2 Column: e

Transfer of Fuel in Process to Fuel in Stock

Schedule Page: 202 Line No.: 3 Column: e

Transfer of Fuel in Process to Fuel in Stock

Schedule Page: 202 Line No.: 4 Column: c

Increase relates to AFUDC for material previously charged to FERC acct. 120.2

Schedule Page: 202 Line No.: 4 Column: e

Transfer related to AFUDC cost from Fuel in Process to Fuel in Stock

Schedule Page: 202 Line No.: 5 Column: e

Transfer Use Tax Cost form Fuel in Process to Fuel in Stock

Schedule Page: 202 Line No.: 8 Column: e

Transfer of Fuel in Stock to Fuel in Reactor

Schedule Page: 202 Line No.: 9 Column: e

Amortization/Retirement of Fuel in Reactor

Schedule Page: 202 Line No.: 13 Column: e

Amortization/Retirement of Fuel in Reactor

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	3,493,100	23,889
4	(303) Miscellaneous Intangible Plant	648,478,838	39,775,729
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	651,971,938	39,799,618
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	5,793,509	
9	(311) Structures and Improvements	159,820,125	14,768,454
10	(312) Boiler Plant Equipment	1,176,686,374	-13,414,111
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	211,794,966	895,990
13	(315) Accessory Electric Equipment	123,412,173	5,143,357
14	(316) Misc. Power Plant Equipment	94,239,796	1,960,089
15	(317) Asset Retirement Costs for Steam Production	4,877,201	37,810,094
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,776,624,144	47,163,873
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	4,417,789	
19	(321) Structures and Improvements	789,134,431	30,893,093
20	(322) Reactor Plant Equipment	1,257,374,596	-14,095,883
21	(323) Turbogenerator Units	382,538,957	22,638,882
22	(324) Accessory Electric Equipment	282,962,874	7,499,150
23	(325) Misc. Power Plant Equipment	166,807,494	30,730,377
24	(326) Asset Retirement Costs for Nuclear Production	-53,660,218	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	2,829,575,923	77,665,619
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	15,722,863	43,806
38	(341) Structures and Improvements	107,546,244	7,945,779
39	(342) Fuel Holders, Products, and Accessories	54,831,437	817,542
40	(343) Prime Movers	667,231,770	2,928,422
41	(344) Generators	1,229,504,103	180,869,002
42	(345) Accessory Electric Equipment	190,761,332	19,763,086
43	(346) Misc. Power Plant Equipment	25,353,749	3,259,414
44	(347) Asset Retirement Costs for Other Production	6,052,254	2,803,813
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,297,003,752	218,430,864
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	6,903,203,819	343,260,356

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	153,274,790	959,119
49	(352) Structures and Improvements	91,126,916	24,191,083
50	(353) Station Equipment	978,521,546	68,379,251
51	(354) Towers and Fixtures	105,328,472	46,093,765
52	(355) Poles and Fixtures	459,350,543	21,489,714
53	(356) Overhead Conductors and Devices	358,514,688	95,909,657
54	(357) Underground Conduit	20,946,613	370,485
55	(358) Underground Conductors and Devices	34,517,731	88,633
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,201,581,299	257,481,707
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	59,259,475	4,422,088
61	(361) Structures and Improvements	80,064,756	2,506,907
62	(362) Station Equipment	466,810,726	32,581,012
63	(363) Storage Battery Equipment	2,123,630	
64	(364) Poles, Towers, and Fixtures	569,327,832	28,661,792
65	(365) Overhead Conductors and Devices	322,336,816	35,110,452
66	(366) Underground Conduit	668,639,083	18,667,497
67	(367) Underground Conductors and Devices	1,587,078,882	69,029,324
68	(368) Line Transformers	812,216,956	27,184,306
69	(369) Services	361,472,932	14,847,014
70	(370) Meters	290,728,809	8,489,415
71	(371) Installations on Customer Premises	42,798,825	918,159
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	73,537,459	1,466,691
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,336,396,181	243,884,657
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	14,645,315	
87	(390) Structures and Improvements	201,571,791	20,644,837
88	(391) Office Furniture and Equipment	185,271,545	45,822,474
89	(392) Transportation Equipment	41,894,156	3,814,969
90	(393) Stores Equipment	237,097	29,297
91	(394) Tools, Shop and Garage Equipment	36,166,224	2,589,474
92	(395) Laboratory Equipment	810,563	
93	(396) Power Operated Equipment	10,681,536	438,030
94	(397) Communication Equipment	231,171,743	32,989,614
95	(398) Miscellaneous Equipment	25,345,405	-7,984,149
96	SUBTOTAL (Enter Total of lines 86 thru 95)	747,795,375	98,344,546
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	747,795,375	98,344,546
100	TOTAL (Accounts 101 and 106)	15,840,948,612	982,770,884
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	15,840,948,612	982,770,884

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			3,516,989		3
1,303,909		1,062,387	688,013,045		4
1,303,909		1,062,387	691,530,034		5
					6
					7
			5,793,509		8
4,629,074			169,959,505		9
6,690,641			1,156,581,622		10
					11
396,443			212,294,513		12
1,408,431			127,147,099		13
1,142,254			95,057,631		14
			42,687,295		15
14,266,843			1,809,521,174		16
					17
			4,417,789		18
3,241,035			816,786,489		19
3,281,236			1,239,997,477		20
4,946,911			400,230,928		21
571,116			289,890,908		22
3,101,078			194,436,793		23
			-53,660,218		24
15,141,376			2,892,100,166		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			15,766,669		37
231,262			115,260,761		38
427,691			55,221,288		39
17,497,704			652,662,488		40
115,114,718			1,295,258,387		41
1,127,095			209,397,323		42
205,628		-1,062,387	27,345,148		43
			8,856,067		44
134,604,098		-1,062,387	2,379,768,131		45
164,012,317		-1,062,387	7,081,389,471		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
1,764,699			152,469,210		48
97,251			115,220,748		49
6,319,306			1,040,581,491		50
1,478			151,420,759		51
1,655,361			479,184,896		52
340,460			454,083,885		53
			21,317,098		54
			34,606,364		55
					56
					57
10,178,555			2,448,884,451		58
					59
1,148,643			62,532,920		60
105,002			82,466,661		61
4,620,455			494,771,283		62
			2,123,630		63
4,881,033			593,108,591		64
2,329,727			355,117,541		65
1,792,910			685,513,670		66
9,727,135			1,646,381,071		67
5,946,179			833,455,083		68
675,204			375,644,742		69
7,854,895			291,363,329		70
161,881			43,555,103		71
					72
402,364			74,601,786		73
					74
39,645,428			5,540,635,410		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
44,688		-554	14,600,073		86
5,980,472		-114,182	216,121,974		87
2,884,897			228,209,122		88
4,930,166		64,167	40,843,126		89
23,879			242,515		90
1,550,861		-64,167	37,140,670		91
			810,563		92
968,369			10,151,197		93
11,715,300			252,446,057		94
29,201		114,182	17,446,237		95
28,127,833		-554	818,011,534		96
					97
					98
28,127,833		-554	818,011,534		99
243,268,042		-554	16,580,450,900		100
					101
					102
					103
243,268,042		-554	16,580,450,900		104

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Roanoke Substation	12/31/1991	12/31/2025	282,772
3	35th Ave. & Roanoke Ave., Phoenix, AZ			
4	Prescott Service Center Office	11/30/2005	12/31/2017	2,004,206
5	Prescott, AZ			
6	Madison Substation	12/31/1993	12/31/2025	592,651
7	11th St. & Jackson St., Phoenix, AZ			
8	Paradise Substation	10/31/2006	12/31/2025	401,192
9	15021 N. 33rd Place, Phoenix, AZ			
10	Punkin Center Substation	12/31/2014	12/31/2025	320,827
11	146 E. Purtill Trail, Tonto Basin, AZ			
12	Sun Valley (TS5) to Trilby Wash (TS1) Transmission	12/31/2008	3/31/2016	14,677,520
13	Township 040N 040W Sec 29; Maricopa, AZ			
14	Palm Valley (TS3) to Trilby Wash (TS1) Transmission	12/31/2008	12/31/2016	18,696,646
15	Township 040N 020W Sec 20; Surprise, AZ			
16	Palo Verde to Sun Valley (TS5) 500KV Transmission Ln	12/31/2008	6/01/2016	4,020,354
17	Township 030N 070W Sec 28; Maricopa, AZ			
18	Buckeye to Elianto (SV4) Transmission Line	5/31/2008	12/31/2017	653,352
19	Township 010N 030W Sec 7; Buckeye, AZ			
20				
21	Other Property:			
22	Other General Parcels (2)	12/31/1999	12/31/2025	281,561
23				
24	Other Transmission Parcels (2)	12/31/1999	12/31/2025	92,023
25				
26	Other Distribution Parcels (4)	12/31/1999	12/31/2025	556,005
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			51,471,935

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Delaney Substation	9/30/2008	6/01/2016	964,987
3	Thomas & 451st Ave.; Maricopa, AZ			
4	Payson Substation	12/31/2008	12/31/2016	746,020
5	Township100N 100E Sec2; Payson, AZ			
6	Sun Valley (TS5) Substation	12/31/2008	6/01/2016	4,825,172
7	Township 04N 04E Sec29; Buckeye, AZ			
8	Via Dona (NE2) Substation	10/31/2008	12/31/2020	1,929,113
9	118th Place & Via Dona Rd; Scottsdale, AZ			
10	Citrus (WS4) Substation	5/01/2009	12/31/2025	427,534
11	Parcel 502-40-267 /T01NR02W.S10/ 2.633 acres			
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			51,471,935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Palo Verde Nuclear Plant Improvements	90,439,655
2	Cholla Plant Improvements	7,960,080
3	Four Corners Plant Improvements	79,006,717
4	Navajo Plant Improvements	4,460,358
5	Gas & Oil Plant Improvements	100,532,030
6	Solar Additions	9,723,027
7		
8	Transmission Land and Land Rights	5,839,397
9	Transmission Substations - Add/Improvements	16,992,140
10	Overhead Transmission Lines - Add/Improvements	42,747,198
11	Underground Transmission Lines - Add/Improvements	11,493,433
12	Other Transmission	686,526
13	ANPP 500 KV Transmission System	1,594,148
14	Navajo Southern Transmission System	396,602
15	PV/YUMA 500 KV Transmission System	133,034
16	Morgan - Pinnacle Peak Transmission System	2,591,729
17	Palo Verde - Morgan 500kV Transmission System	133,813,037
18	Phoenix - Mead Transmission System	150,908
19		
20	Distribution Land and Land Rights	327,572
21	Distribution Substation - Add/Improvements	9,420,141
22	Overhead Distribution Lines - Add/Improvements	25,876,619
23	Underground Distribution Lines - Add/Improvements	19,746,477
24	Other Distribution	7,587,737
25		
26	General Computer/Communications	113,594,914
27	Buildings & Equip/Land & Land Rights	28,173,856
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	713,287,335

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	5,520,859,057	5,520,859,057		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	385,402,361	385,402,361		
4	(403.1) Depreciation Expense for Asset Retirement Costs	70,077	70,077		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,852,644	1,852,644		
7	Other Clearing Accounts	506,214	506,214		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	387,831,296	387,831,296		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	232,771,289	232,771,289		
13	Cost of Removal	33,160,314	33,160,314		
14	Salvage (Credit)	68,094,492	68,094,492		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	197,837,111	197,837,111		
16	Other Debit or Cr. Items (Describe, details in footnote):	-32,448,282	-32,448,282		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,678,404,960	5,678,404,960		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,126,134,742	1,126,134,742		
21	Nuclear Production	1,532,908,333	1,532,908,333		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	567,646,629	567,646,629		
25	Transmission	722,951,477	722,951,477		
26	Distribution	1,526,576,630	1,526,576,630		
27	Regional Transmission and Market Operation				
28	General	202,187,149	202,187,149		
29	TOTAL (Enter Total of lines 20 thru 28)	5,678,404,960	5,678,404,960		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 12 Column: b

FERC Page 219 Column (b), Line 12	**232,771,289**
Cholla Unit 2 - NBV of Retirement moved to Regulatory Asset (182.3)	491,054
Gain/(Loss) on Disposition of Assets	(493,858)
FERC Page 204-207 Column (d), Line 5	1,303,909
FERC Page 204-207 Column (d), Line 48	1,764,699
FERC Page 204-207 Column (d), Line 60	1,148,643
General Plant Retirements	6,256,596
Other	25,710
FERC Page 204-207 Column (d), Line 104	**243,268,042**

Schedule Page: 219 Line No.: 16 Column: c

Palo Verde Decommissioning	(15,663,590)
Asset Retirement Obligation in Reg. Liability	(3,880,699)
Accelerated CIAC to Regulatory Assets	(332,041)
Childs Irving Decommissioning	441,067
SCE Four Corners U4-5 - Accretion	(2,791,073)
Cholla Unit 2 Regulatory Asset/Liability	(7,417,361)
Saguaro Steam Regulatory Asset Amortization	(2,936,533)
Reserve Transfers-- Accounts 1110,1112, & 1220 & Other Entities	131,948
	(32,448,282)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
				42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	32,263,222	38,345,560	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	114,840,074	120,438,920	
8	Transmission Plant (Estimated)	30,450,516	34,331,669	
9	Distribution Plant (Estimated)	73,808,775	77,675,882	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	455,476	490,631	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	219,554,841	232,937,102	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	-666,160	1,296,535	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	251,151,903	272,579,197	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 7 Column: b

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

Schedule Page: 227 Line No.: 7 Column: c

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

Schedule Page: 227 Line No.: 8 Column: b

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

Schedule Page: 227 Line No.: 8 Column: c

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

Schedule Page: 227 Line No.: 9 Column: b

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

Schedule Page: 227 Line No.: 9 Column: c

The method used to allocate the materials and supplies to production including intangible and general, transmission and distribution is to allocate the total materials and supplies inventory, after the amount assigned to other, based on a plant allocator as derived from the applicable plant to total electric plant in service as found on page 207.

Schedule Page: 227 Line No.: 11 Column: b

Assigned to - Other. General Plant expenses for communication and garage equipment.

Schedule Page: 227 Line No.: 11 Column: c

Assigned to - Other. General Plant expenses for communication and garage equipment.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	209,943.00		48,487.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	7,366.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	202,577.00		48,487.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	533.00		533.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA	533.00			
39	Cost of Sales				
40	Balance-End of Year			533.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	533.00	62		
45	Gains		62		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
48,487.00		48,487.00		1,260,662.00		1,616,066.00		1
								2
								3
				48,487.00		48,487.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						7,366.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
48,487.00		48,487.00		1,309,149.00		1,657,187.00		29
								30
								31
								32
								33
								34
								35
533.00		533.00		26,091.00		28,223.00		36
				1,066.00		1,066.00		37
				533.00		1,066.00		38
								39
533.00		533.00		26,624.00		28,223.00		40
								41
								42
								43
				533.00	17	1,066.00	79	44
					17		79	45
								46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 228   Line No.: 29   Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding line item on page 110. The difference is due to ending balance of $7,351,348 in CO2 allowances issued by the California Air Resources Board (CARB).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	FACIL STDY,WA131362	(2)	143		143
23	FACIL STDY,WA144239	(45)	143		143
24	FACIL STDY,WA183634	730	143		143
25	SMG FESSTD,WA310886	431	143	(1,000)	143
26	SMG SISSTD,WA310005	193	143	(50,000)	143
27	SYSIMPTSTD,W502466	(3)	143		143
28	SYSIMPTSTD,WA158156	(10)	143		143
29	SYSIMPTSTD,WA173723	(702)	143		143
30	SYSIMPTSTD,WA201230	938	143		143
31	SYSIMPTSTD,WA205085	109	143		143
32	SYSIMPTSTD,WA223536	362	143		143
33	SYSIMPTSTD,WA305310	(3,475)	143		143
34	SYSIMPTSTD,WA307280	2,114	143		143
35	SYSIMPTSTD,WA307466	(203)	143		143
36	SYSIMPTSTD,WA309370	781	143	(160,000)	143
37	SYSIMPTSTD,WA309377	(164)	143	(250,000)	143
38	SYSIMPTSTD,WA85636	(1)	143		143
39	SYSIMPTSTD,WA92332	(10)	143		143
40	SYSIMPTSTD,WA95638	(13)	143		143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Compensation	34,162,184	588,664			34,750,848
2	Amortize through 2036					
3						
4	Capital Contribution on Phoenix-Mead Transmission	11,704,442		108	332,042	11,372,400
5	U-1345-90-269 Amortize through 2050					
6						
7	Income Taxes - AFUDC Equity	123,209,269	20,745,899	283, 410.1	4,748,533	139,206,635
8	E-01345A-03-0437 Amortize through 2045					
9						
10	Palo Verde Rent Levelization	762,791		525	762,791	
11	E-01345A-03-0437 Amortize through 2015					
12						
13	Decontamination	60,331		407	55,045	5,286
14	E-01345A-03-0437 Amortize through 2016					
15						
16	Prior Flow Through of Tax Benefits	5,499,900		190	1,979,901	3,519,999
17	Amortize through 2019					
18						
19	Deferred Fuel and Purchased Power	6,925,515		various	6,925,515	
20	E-01345A-03-0437, E-01345A-05-0816, -0826, -0827					
21	Amortize through 2015					
22						
23	Deferred Fuel and Purchased Power Mark-to-Market	97,442,048	44,106,082			141,548,130
24	E-01345A-03-0437, E-01345A-05-0816, -0826, -0827					
25	Amortize through 2018					
26						
27	Navajo Coal Reclamation	6,920,553		501	417,890	6,502,663
28	E-01345A-08-0172 Amortize through 2026					
29						
30	Transmission Vegetation Management	13,629,492		571	9,086,328	4,543,164
31	ER11-3468-000 Amortize through 2016					
32						
33	Pension Benefits	485,036,791	160,069,622	421, 908	25,883,494	619,222,919
34	E-01345A-08-0172					
35						
36	Pension and Other Postretirement Benefits Deferral	4,237,507		926	4,237,507	
37	E-01345A-08-0172					
38	Amortize through 2015					
39						
40	Income Taxes - Change in Rates	3,049,996		283, 410.1	64,132	2,985,864
41	Amortize through 2045					
42						
43	Income Taxes - Medicare Subsidy	15,284,238		283, 410.1	1,600,431	13,683,807
44	TOTAL	1,147,084,875	299,630,604		112,541,373	1,334,174,106

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Amortize through 2024					
2						
3	Income Taxes - Investment Tax Credit Basis Adjustmt	47,916,218	4,062,799	283	1,750,604	50,228,413
4	Amortize through 2045					
5						
6	Property Tax Deferral	30,282,583	20,169,839			50,452,422
7	E-01345A-11-0224					
8						
9	Lost Fixed Cost Recovery	37,612,494	45,987,954	142	38,093,998	45,506,450
10	Amortize through 2016					
11	E-01345A-11-0224					
12						
13	FERC Transmission Cost Adjustor		2,942,299			2,942,299
14	Amortize through 2017					
15	E-01345A-11-0224					
16						
17	Retired Power Plant Costs	146,095,252	1,251,069	403	9,914,441	137,431,880
18	Amortize through 2033					
19						
20	Four Corners Cost Deferral	77,253,271	(293,623)	407	6,688,721	70,270,927
21	Amortize through 2024					
22	E-01345A-11-0224					
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,147,084,875	299,630,604		112,541,373	1,334,174,106

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 19 Column: d

411.8, 426.5, 555

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Rouse Promissory Note	77,085	154,166	131	231,251	
2	(01/2015)					
3						
4	Rouse Deferred Lease Payments	89,280,343	8,064,846	931	3,443,429	93,901,760
5	(Through 2045)					
6						
7	Redhawk Effluent Water	200,000	143,750	232	143,750	200,000
8						
9	Information Sys Leases & Maint.	7,941,626	88,635,308	165	89,317,968	7,258,966
10						
11	Unamortized Arrangement Fees	3,691,195	2,855,461	431, 525	2,884,228	3,662,428
12						
13	Prepaid Training	48,250		232	48,250	
14	(03/2011 to 03/2016)					
15						
16	High Lonesome Wind Ranch Tax Cr	1,083,722		142	1,083,722	
17						
18	Transmission Debits	9,350,838	2,630,788	565	4,439,035	7,542,591
19	(11/2014 to 03/2016)					
20						
21	Prepaid Payroll Agreements	294,601				294,601
22						
23	Prepaid Water Supply Agreements	7,689,648		165	421,224	7,268,424
24	Through 2050					
25						
26	Debt Shelf Registration	290,349	115,899	various	406,248	
27						
28	Freight in Transit	837,424	1,057,611	232	1,810,802	84,233
29						
30	Prepaid Monitoring Services	757,985		165	44,388	713,597
31	(2014 to 2023)					
32						
33	Long Term Prepaid Insurance	-8	5,672,931	165	5,672,923	
34						
35	Rapid Response Center Equipment		790,494	232		790,494
36						
37	Minor Items	296,955	396,052	various	285,676	407,331
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	121,840,013				122,124,425

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 26 Column: d

181, 428, 431

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Risk Management Activities	66,251,274	80,616,150
3	Pension and Other Post Retirement Liabilities	194,541,344	181,786,916
4	Regulated Liabilities - Asset Retirement Obligation	115,824,489	107,885,455
5	Regulated Liabilities - Other	248,332,195	245,681,167
6	Other	226,548,062	236,971,165
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	851,497,364	852,940,853
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	851,497,364	852,940,853

Notes

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	100,000,000	2.50	
2				
3	Total Common Stock	100,000,000		
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
71,264,947	178,162,368					1
						2
71,264,947	178,162,368					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Gain on Resale or Cancellation of Capital Stock - Account 210	1,505,626
2	Balance at Beginning of Year: $1,505,626	
3	Credits	
4	Debits	
5	Balance at End of Year: $1,505,626	
6		
7	Misc Paid in Capital - Account 211	
8	Transfer of Contract from Pinnacle West Marketing & Trading LLC	12,323,739
9	Balance at Beginning of Year: $12,323,739	
10	Credit	
11	Debit	
12	Balance at End of Year: $12,323,739	
13		
14	El Dorado transfer of Aegis software to APS	4,571,000
15	Balance at Beginning of Year: $4,571,000	
16	Credit	
17	Debit	
18	Balance at End of Year: $4,571,000	
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	18,400,365

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 253 Line No.: 8 Column: a

Pinnacle West Marketing & Trading LLC is a subsidiary of Pinnacle West Capital Corporation, parent to Arizona Public Service Company.

Schedule Page: 253 Line No.: 14 Column: a

El Dorado is a subsidiary of Pinnacle West Capital Corporation, parent to Arizona Public Service Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense	37,461,284
2	Shelf Registration	50,368
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	37,511,652

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Pollution Control Bonds Account 221		
2	Farmington, NM Pollution Control Revenue Refunding Bonds. 1994 Series A	49,400,000	1,062,971
3	Farmington, NM Pollution Control Revenue Refunding Bonds. 1994 Series B	65,750,000	1,314,678
4	Coconino County, AZ Pollution Cntrl Corp Polllution Cntrl Rev Bonds. Series 1998	16,870,000	538,817
5	Coconino County, AZ Pollution Cntrl Corp Polllution Cntrl Rev Bonds. 2009 Series A	12,850,000	544,829
6	Coconino County, AZ Pollution Cntrl Corp Polllution Cntrl Rev Bonds. 2009 Series B	26,710,000	653,379
7	Navajo County, AZ Pollution Cntrl Corp Polllution Cntrl Rev Bonds. 2009 Series A	38,150,000	749,617
8	Navajo County, AZ Pollution Cntrl Corp Polllution Cntrl Rev Bonds. 2009 Series C	32,000,000	282,336
9	Navajo County, AZ Pollution Cntrl Corp Polllution Cntrl Rev Bonds. 2009 Series D	32,000,000	411,777
10	Navajo County, AZ Pollution Cntrl Corp Polllution Cntrl Rev Bonds. 2009 Series E	32,000,000	391,683
11	Maricopa County, AZ Pollution Cntrl Corp Pollution Cntrl Rev Bonds. 2009 Series A	35,975,000	576,013
12	Maricopa County, AZ Pollution Cntrl Corp Pollution Cntrl Rev Bonds. 2009 Series B	32,000,000	758,122
13	Maricopa County, AZ Pollution Cntrl Corp Pollution Cntrl Rev Bonds. 2009 Series C	32,000,000	445,268
14	Subtotal	405,705,000	7,729,490
15			
16	Other Long Term Debt Account 224		
17	5.625% Unsecured Senior Note	200,000,000	2,049,339
18			2,288,000 D
19	4.650% Unsecured Senior Note	300,000,000	2,529,839
20			2,208,000 D
21	5.500% Unsecured Senior Note	250,000,000	2,362,692
22			2,147,500 D
23	6.250% Unsecured Senior Note	250,000,000	1,659,703
24			1,355,000 D
25	6.875% Unsecured Senior Note	150,000,000	1,333,769
26			226,500 D
27	8.750% Unsecured Senior Note	500,000,000	4,301,413
28			275,000 D
29	5.05% Unsecured Senior Note	300,000,000	3,096,550
30			2,022,000 D
31	4.50% Unsecured Senior Note	325,000,000	3,321,373
32			3,074,500 D
33	TOTAL	4,159,400,075	52,724,392

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.50% Unsecured Senior Note	100,000,000	1,148,640
2			-5,182,000 P
3	4.7% Unsecured Senior Note	250,000,000	2,501,050
4			1,000,000 D
5	3.35% Unsecured Senior Note	250,000,000	2,080,950
6			230,000 D
7	2.20% Unsecured Senior Note	250,000,000	2,103,800
8			35,000
9	3.15% Unsecured Senior Note	300,000,000	2,384,360
10			1,578,000
11	4.35% Unsecured Senior Note	250,000,000	2,518,924
12			335,000
13			
14	APS Term Loan	50,000,000	10,000
15			
16	COLI LOANS (Option II Benefits)	28,695,075	
17			
18	Subtotal	3,753,695,075	44,994,902
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	4,159,400,075	52,724,392

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
5/25/94	5/01/24	5/25/94	5/01/24	49,400,000	2,321,800	2
9/14/94	9/01/24	9/14/94	9/01/24	65,750,000	3,090,250	3
11/16/98	11/01/33	11/16/98	11/01/33	16,870,000	166,729	4
5/28/09	6/01/34	5/28/09	6/01/34	12,850,000	39,014	5
9/22/09	4/01/38	9/22/09	4/01/38	26,710,000	263,169	6
5/28/09	6/01/34	5/28/09	6/01/34		149,739	7
5/28/09	6/01/34	5/28/09	6/01/34		232,669	8
5/28/09	6/01/34	5/28/09	6/01/34	32,000,000	1,840,000	9
5/28/09	6/01/34	5/28/09	6/01/34	32,000,000	1,840,000	10
6/26/09	5/01/29	6/26/09	5/01/29	35,975,000	120,632	11
6/26/09	5/01/29	6/26/09	5/01/29		87,980	12
6/26/09	5/01/29	6/26/09	5/01/29	32,000,000	560,000	13
				303,555,000	10,711,982	14
						15
						16
5/07/03	5/15/33	5/07/03	5/15/33	200,000,000	11,250,000	17
						18
5/07/03	5/15/15	5/07/03	5/15/15		5,231,250	19
						20
8/22/05	9/01/35	8/22/05	9/01/35	250,000,000	13,750,000	21
						22
8/03/06	8/01/16	8/03/06	8/01/16	250,000,000	15,625,000	23
						24
8/03/06	8/01/36	8/03/06	8/01/36	150,000,000	10,312,500	25
						26
2/26/09	3/01/19	2/26/09	3/01/19	500,000,000	43,750,000	27
						28
8/25/11	9/01/41	8/25/11	9/01/41	300,000,000	15,150,000	29
						30
1/13/12	4/01/42	1/13/12	4/01/42	325,000,000	14,625,000	31
						32
				3,757,250,075	178,395,658	33

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
1/13/12	4/01/42	1/13/12	4/01/42	100,000,000	4,500,000	1
						2
1/10/14	1/15/44	1/10/14	1/15/44	250,000,000	11,750,000	3
						4
6/18/14	6/15/24	6/18/14	6/15/24	250,000,000	8,375,000	5
						6
1/12/15	1/15/20	1/12/15	1/15/20	250,000,000	5,500,000	7
						8
5/19/15	5/15/25	5/19/15	5/15/25	300,000,000	5,880,000	9
						10
11/06/15	11/15/45	11/06/15	11/15/45	250,000,000	1,776,250	11
						12
						13
6/26/15	6/26/18	6/26/15	6/26/18	50,000,000	208,676	14
						15
				28,695,075		16
						17
				3,453,695,075	167,683,676	18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				3,757,250,075	178,395,658	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 1 Column: a

Although provisions in APS's articles of incorporation and ACC financing orders establish maximum amounts of preferred stock and debt that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements. On February 6, 2013, the ACC issued a financing order in which it, subject to specified parameters and procedures, (a) approved APS's short-term debt authorization equal to a sum of (i) 7% of APS's capitalization, and (ii) $500 million (which is required to be used for costs relating to purchases of natural gas and power), (b) approved an increase in APS's long-term debt authorization from $4.2 billion to $5.1 billion in light of the projected growth of APS and its customer base and the resulting projected financing needs, and (c) authorized APS to enter into derivative financial instruments for the purpose of managing interest rate risk associated with its long- and short-term debt. This financing order is set to expire on December 31, 2017.

Schedule Page: 256.1 Line No.: 16 Column: h

The change in the loan balance for the Coli Loan is as follows:

Total outstanding balance @ 12/31/14	$ 27,577,791
2015 death repayments	(539,091)
2015 net premiums	521,842
2015 net interest	1,134,533
Balance outstanding @ 12/31/15	$ 28,695,075

Schedule Page: 256.1 Line No.: 18 Column: i

The difference between the total column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies is as follow:

Total interest in 427 and 430	$ 179,563,539
Less:	
Navajo ROW – Past Obligation	(1,060,365)
Letter of Credit Fees	(97,515)
Other	(10,000)
Total long term interest	$ 178,395,659

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	450,274,046
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	43,468,266
6	Tax Gain/Loss on Sale of Business Property	-29,603,211
7	Other Taxable Income Not Reported on Books	12,412,514
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	552,712,170
11	Income Tax Per Books	246,022,753
12	Pension and Other Post-Retirement Benefits	-516,615
13	Other Deductions Recorded on Books Not Deducted for Return	226,907,566
14	Income Recorded on Books Not Included in Return	
15	Book Gain/Loss on Sale of Business Property	1,503,253
16	Mark-to-Market Adjustments	-380,716
17	Cash Surrender Value	-1,134,553
18	Other Income Recorded on Books Not Included in Return	-1,493,647
19	Deductions on Return Not Charged Against Book Income	
20	Tax Depreciation and Amortization	-820,958,164
21	Expenditures Capitalized for Book Not Tax	-260,341,446
22	Other Deductions on Return Not Charged Against Book Income	-312,163,353
23		
24		
25		
26		
27	Federal Tax Net Income	106,708,863
28	Show Computation of Tax:	
29	($106,708,863) * 35%	37,348,102
30		
31	Tax Attributes Utilized	-18,648,856
32		
33	Net Current Year Federal Tax Expense	18,699,246
34		
35	Other (includes 2014 Return-to-Provision)	-3,388,363
36		
37	Net Federal Tax Expense per Income Statement	15,310,883
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 13 Column: b

Other Deductions Recorded on Books Not Deducted for Return consists of the following:

Book Accrued Expenses - End of Year	$	198,115,157
Regulatory Accounting Adjustments		18,320,277
Other		10,472,132
Total	$	226,907,566

Schedule Page: 261 Line No.: 22 Column: b

Other Deductions on Return Not Charged Against Book Income consists of the following:

Book Accrued Expenses - Beginning of Year	$	(172,957,792)
Pension and Other Post Retirement Benefits		(74,442,645)
Regulatory Accounting Adjustments		(34,203,283)
Contributions to Qualified Decomissioning Fund		(17,248,943)
State Taxes		(5,086,351)
Other		(8,224,339)
Total	$	(312,163,353)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal Income	13,485,795		15,310,883	7,841,954	
2	FICA			50,166,332	50,166,332	
3	Unemployment			295,018	295,018	
4	Heavy Vehicle Use	-37,340		73,727	86,762	
5	Fuel Tax	-24,415			1,759	
6	Subtotal	13,424,040		65,845,960	58,391,825	
7						
8	New Mexico: State and Local					
9	Real and Personal Property	7,803,549		16,448,738	15,875,295	
10	Income	21,791		477,477	180,622	
11	Unemployment			53,494	53,494	
12	Sales	3,288		146,668	164,409	
13	Use	-95		11,179	11,370	
14	Subtotal	7,828,533		17,137,556	16,285,190	
15						
16	Arizona: State and Local					
17	Real and Personal Property	87,638,164		178,162,090	176,766,037	
18	Income	444,418		6,794,954	6,200,000	
19	Diesel Fuel					
20	State and City Sales	16,767,805		264,154,556	263,920,314	
21	State and City Use	965,091		17,201,515	16,653,984	
22	State and City Tax Reserve	5,977,153		1,435,134	766,302	-190,000
23	Unemployment			1,479,763	1,479,763	
24	Subtotal	111,792,631		469,228,012	465,786,400	-190,000
25						
26	NV Real and Personal	30,202		117,105	147,306	
27	Unemployment					
28	Subtotal	30,202		117,105	147,306	
29						
30	California: State and Local					
31	Real and Personal Property	13,940		28,269	42,210	
32	Income	69,601		540,970	608,083	
33	Unemployement					
34	Subtotal	83,541		569,239	650,293	
35						
36	Utah: State					
37	Income					
38	Subtotal					
39						
40						
41	TOTAL	142,296,215		552,897,872	541,261,014	78,223

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Texas: State					
2	Income					
3	Unemployment					
4	Subtotal					
5						
6	Sales Tax - Palo Verde Lease					
7	Payroll - other					
8	Sales Tax - Unbilled Revenue	9,137,268				268,223
9	Subtotal	9,137,268				268,223
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	142,296,215		552,897,872	541,261,014	78,223

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
20,954,724		21,013,707			-5,702,824	1
		26,229,310			23,937,022	2
					295,018	3
-50,375					73,727	4
-26,174						5
20,878,175		47,243,017			18,602,943	6
						7
						8
8,376,992		16,448,738				9
318,646		511,574			-34,097	10
					53,494	11
-14,453					146,668	12
-286					11,179	13
8,680,899		16,960,312			177,244	14
						15
						16
89,034,216		155,002,981			23,159,110	17
1,039,372		7,734,403			-939,449	18
						19
17,002,047					264,154,556	20
1,512,753					17,201,515	21
6,455,985		-97,776			1,342,909	22
					1,479,763	23
115,044,373		162,639,608			306,398,404	24
						25
		117,105				26
						27
		117,105				28
						29
						30
		28,269				31
2,488		552,850			-11,880	32
						33
2,488		581,119			-11,880	34
						35
						36
						37
						38
						39
						40
154,011,438		227,541,161			325,434,934	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
						4
						5
						6
						7
9,405,503					268,223	8
9,405,503					268,223	9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
154,011,438		227,541,161			325,434,934	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	265,395	255		420	81,816	
6	30%	178,341,815	255	15,090,394	420	6,535,366	
7							
8	TOTAL	178,607,210		15,090,394		6,617,182	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
183,579	2.2 years		5
186,896,843	27.3 years		6
			7
187,080,422			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 266 Line No.: 8 Column: b

$33,587 is associated with transmission investments.

Schedule Page: 266 Line No.: 8 Column: h

$23,099 is associated with transmission investments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Compensation	5,906,506	182.3	1,148,634	49,083	4,806,955
2						
3	Palo Verde Unit II Rent					
4	Levelization (1/2000 to 12/2015	4,747,577	242, 411.6	4,747,577		
5						
6	Coal Reclamation	190,307,870	232	1,470,235	5,475,749	194,313,384
7						
8	Navajo Retiree Health Care Costs	7,984,308	182.3, 501	313,811		7,670,497
9						
10	Legal Reserves	6,631,850	131	1,006,524	354,253	5,979,579
11						
12	Construction Advances	4,534,314	143	22,403,053	23,141,284	5,272,545
13						
14	Land Lease Obligations	522,091	165, 555		179,547	701,638
15	Through 2048					
16						
17	Transmission Termination Agreemnts	6,000,000	242	6,000,000		
18						
19	License Fees	1,182,716	930.2		1,195,391	2,378,107
20						
21	Leasehold Improvements	85,444	131	205,124	171,011	51,331
22						
23	Escheated Funds	50,875	131	42,223	37,338	45,990
24						
25	SCE Right of Way	19,960,113	232, 567	290,640		19,669,473
26						
27	Tolling Agreements	26,641,345	232	26,194,533	19,472,788	19,919,600
28						
29	Coal Severance Surtax Reserve	1,922,000	501			1,922,000
30						
31	Carbon Allowance		509, 242	493,655	5,683,502	5,189,847
32						
33	OCC Modernization Overland Retentn		107		268,548	268,548
34	Through 2018					
35						
36	House Warranty Program		456	50,000	750,000	700,000
37	Through 2020					
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	276,477,009		64,366,009	56,778,494	268,889,494

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	2,844,422,368	601,832,113	438,382,734
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,844,422,368	601,832,113	438,382,734
6				
7				
8	UTP recorded in ADIT for FERC	33,567,715	-8,643,667	
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,877,990,083	593,188,446	438,382,734
10	Classification of TOTAL			
11	Federal Income Tax	2,404,272,915	566,006,339	277,694,051
12	State Income Tax	473,717,168	27,182,107	160,688,683
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						3,007,871,747	2
							3
							4
						3,007,871,747	5
							6
							7
						24,924,048	8
						3,032,795,795	9
							10
						2,692,585,203	11
						340,210,592	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Reg. Assets - AFUDC	48,285,714	10,356,261	4,532,356
4	Reg Assets - Mark to Market	38,187,540	18,346,292	1,514,074
5	Reg Assets - Pension and Other	191,746,602	54,628,463	5,683,116
6	Reg Assets - Other	160,071,551	95,322,271	82,808,594
7	Mark to Market	20,916,759	8,952,993	5,895,753
8	Other	63,978,469	17,632,203	15,204,098
9	TOTAL Electric (Total of lines 3 thru 8)	523,186,635	205,238,483	115,637,991
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	523,186,635	205,238,483	115,637,991
20	Classification of TOTAL			
21	Federal Income Tax	437,070,114	177,797,974	84,435,911
22	State Income Tax	86,116,521	27,440,509	31,202,080
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						54,109,619	3
						55,019,758	4
						240,691,949	5
						172,585,228	6
		219	3,229,718			20,744,281	7
						66,406,574	8
			3,229,718			609,557,409	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			3,229,718			609,557,409	19
							20
			2,908,159			527,524,018	21
			321,559			82,033,391	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	PacifiCorp CT Deferred Gain	10,000,000	456	2,000,000		8,000,000
2	U-1345-90-269 Amortize through 2019					
3						
4	Asset Retirement Obligation	295,546,022	230	17,991,469		277,554,553
5	FERC Order #552 Amortize through 2057					
6						
7	Spent Nuclear Fuel Storage	69,990,113	518	842,083	1,340,275	70,488,305
8	E-01345A-03-0437, E-01345A-05-0816, -0826,					
9	-0827 Amortize through 2047					
10						
11	Income Taxes - Unamortized Investment Tax Credit	96,231,975	190	3,573,590	8,120,830	100,779,215
12	E-01345A-05-0816,-0826,-0827					
13	Amortize through 2045					
14						
15	Sundance Maintenance	12,069,000			1,609,200	13,678,200
16	E-01345A-05-0816,-0826,-0827					
17	Amortize through 2030					
18						
19	Income Tax - Change in Rates	75,844,021	283	1,163,806	1,872,696	76,552,911
20	Amortize through 2045					
21						
22	Amonix Promissory Note	6,161,929				6,161,929
23						
24	Renewable Energy Standard	45,975,945	549	126,253,481	127,615,209	47,337,673
25	E-01345A-03-0437,E-01345A-05-0816,-0826,					
26	-0827 Amortize through 2017					
27						
28	Star Center Patent Rights	1,125,393				1,125,393
29	E-01345A-09-0357					
30						
31	AZ Sun Program	1,296,595	400	496,465		800,130
32	E-01345A-09-0338 Amortize through 2016					
33						
34	Excess Deferred Taxes	5,499,900	190	1,979,900		3,520,000
35	Amortize through 2019					
36						
37	Demand Side Management	31,334,718	908	56,912,075	50,770,665	25,193,308
38	E-01345A-03-0437, E-01345A-05-0816, -0826, -0827					
39	Amortize through 2017					
40						
41	TOTAL	899,167,049		253,649,996	234,007,460	879,524,513

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Other Postretirement Benefits	230,915,494	228.3	33,008,940	15,713,896	213,620,450
2	E-01345A-08-0172					
3						
4	FERC Transmission True Up	2,266,649	400	4,119,219	3,495,000	1,642,430
5	Amortize through 2016					
6						
7	Removal costs Cholla	13,102,784			439,873	13,542,657
8	Amortize through 2033					
9						
10	Power Supply Adjuster		various	5,308,968	14,996,475	9,687,507
11	Amortize through 2016					
12	E-01345A-05-0816,-0826,-0827					
13						
14	Power Supply Adjuster Interest	551,028			312,978	864,006
15	Amortize through 2016					
16	E-01345A-05-0816,-0826,-0827					
17						
18	Four Corners Coal Reclamation	1,200,127			7,719,624	8,919,751
19	E-013454A-05-0816, -0826, -0827					
20	Amortize through 2031					
21						
22	Minor Items	55,356			739	56,095
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	899,167,049		253,649,996	234,007,460	879,524,513

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 278.1 Line No.: 10 Column: c

411.8, 426.5, 555

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,701,967,569	1,639,833,740
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,375,003,302	1,349,585,933
5	Large (or Ind.) (See Instr. 4)	186,410,252	187,964,502
6	(444) Public Street and Highway Lighting	22,444,231	21,012,878
7	(445) Other Sales to Public Authorities	187,560	182,742
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,286,012,914	3,198,579,795
11	(447) Sales for Resale	176,840,127	258,829,659
12	TOTAL Sales of Electricity	3,462,853,041	3,457,409,454
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	3,462,853,041	3,457,409,454
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,400,013	8,113,649
17	(451) Miscellaneous Service Revenues	9,290,021	9,321,356
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	-1,185,197	10,564,649
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	5,519,062	5,882,123
22	(456.1) Revenues from Transmission of Electricity of Others	34,768,234	30,931,241
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	56,792,133	64,813,018
27	TOTAL Electric Operating Revenues	3,519,645,174	3,522,222,472

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
13,159,754	12,837,752	1,046,989	1,033,728	2
				3
12,364,153	12,337,218	125,579	124,460	4
2,275,533	2,269,263	3,744	3,728	5
148,229	137,571	1,028	1,007	6
2,822	2,729	154	156	7
				8
				9
27,950,491	27,584,533	1,177,494	1,163,079	10
5,678,363	5,366,855	47	55	11
33,628,854	32,951,388	1,177,541	1,163,134	12
				13
33,628,854	32,951,388	1,177,541	1,163,134	14

Line 12, column (b) includes $ -4,300,886 of unbilled revenues.

Line 12, column (d) includes 1,648 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 4 Column: b

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

Schedule Page: 300 Line No.: 4 Column: c

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Includes unmetered sales such as traffic lights, bus stop lighting, and public irrigation systems.

Schedule Page: 300 Line No.: 5 Column: b

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Schedule Page: 300 Line No.: 5 Column: c

Basis of classification for small or large commercial and industrial sales is customer's NAICS code.

Schedule Page: 300 Line No.: 17 Column: b

Connection Charges	$	9,287,522
Other		$2,499
Total	$	9,290,021

Schedule Page: 300 Line No.: 17 Column: c

Connection Charges	$	9,186,485
Other		134,871
Total	$	9,321,356

Schedule Page: 300 Line No.: 21 Column: b

PCS Project	$	2,596,707
PacifiCorp CT Deferred Gain Amortization		2,000,000
Fuel Loading		985,646
Facility Charges		946,676
Effluent Water Rights Fee		682,764
Management/Administration Fees		650,822
Other		269,874
Call Center Referrals		218,840
Participant Station Power Revenue		124,722
Home Warranty Program		50,084
Redhawk Miscellaneous Revenue		(9,426)
Risk Management		(1,446,105)
Surepay and Autopay Discount		(1,551,542)
Total	$	5,519,062

Schedule Page: 300 Line No.: 21 Column: c

PCS Project	$	2,629,500
PacifiCorp CT Deferred Gain Amortization		2,000,000
Facility Charges		710,904
Fuel Loading		976,120
Management/Administration Fees		727,288
Participant Station Power Revenue		136,363

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Surepay and Autopay Discount		(1,509,350)
Risk Management		(802,409)
Renewable Energy Misc Revenue		50,000
Effluent Water Rights Fee		646,001
Other		317,706
Total	$	5,882,123

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential					
2	E-12	3,679,589	519,663,383	466,329	7,891	0.1412
3	ET-1	2,129,322	272,689,926	133,692	15,927	0.1281
4	ET-2	4,299,349	555,257,808	293,586	14,644	0.1291
5	ECT-2	2,130,107	246,471,622	92,478	23,034	0.1157
6	ECT-1R	667,386	77,430,213	26,272	25,403	0.1160
7	ECT-SP	22,584	2,871,559	1,559	14,486	0.1272
8	E-12 EPR-2,6	33,613	5,548,405	12,018	2,797	0.1651
9	ET-1 EPR-2,6	40,462	4,789,604	5,584	7,246	0.1184
10	ET-2 EPR-2,6	114,735	13,736,332	14,019	8,184	0.1197
11	ECT-2 EPR-2,6	12,285	1,751,250	883	13,913	0.1426
12	ECT-1R EPR-2,6	5,856	824,707	351	16,684	0.1408
13	ET-EV	5,287	609,890	218	24,252	0.1154
14	E-47	1,702	540,066			0.3173
15	Green Power		144,757			
16	Total Residential	13,142,277	1,702,329,522	1,046,989	12,552	0.1295
17						
18	442 Commercial					
19	E-20	38,617	4,939,546	393	98,262	0.1279
20	E-30	4,972	1,281,885	4,348	1,144	0.2578
21	E-32 XS	1,444,763	235,430,207	97,331	14,844	0.1630
22	E-32 S	2,500,461	333,409,187	16,128	155,039	0.1333
23	E-32 M	2,842,734	306,934,665	3,636	781,830	0.1080
24	E-32 L	2,287,045	208,334,549	618	3,700,720	0.0911
25	E-32 TOU XS	5,605	857,946	239	23,452	0.1531
26	E-32 TOU S	29,184	3,654,592	124	235,355	0.1252
27	E-32 TOU M	68,203	7,083,445	69	988,449	0.1039
28	E-32 TOU L	175,275	15,507,244	39	4,494,231	0.0885
29	SCHOOL TOU RATE M	40,800	5,095,290	59	691,525	0.1249
30	SCHOOL TOU RATE L	27,051	3,139,659	20	1,352,550	0.1161
31	E-34	413,609	33,443,264	16	25,850,563	0.0809
32	E-35	831,971	57,936,625	19	43,787,947	0.0696
33	E-36 M	6,615	723,094	9	735,000	0.1093
34	E-47	20,552	8,396,353			0.4085
35	E-56	1,056	749,249	1	1,056,000	0.7095
36	E-221	323,537	33,315,122	1,357	238,421	0.1030
37	EPR-2	7,442	764,258	24	310,083	0.1027
38	EPR-6	369,588	45,313,330	954	387,409	0.1226
39	Green Power		637,987			
40	E-56R	307,007	24,562,721	45	6,822,378	0.0800
41	TOTAL Billed	27,948,843	3,290,313,800	1,172,568	23,836	0.1177
42	Total Unbilled Rev.(See Instr. 6)	1,648	-4,300,886	4,926	335	-2.6098
43	TOTAL	27,950,491	3,286,012,914	1,177,494	23,737	0.1176

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	AG-1 M & L	451,707	34,800,506	143	3,158,790	0.0770
2	AG-1 M & L TOU	11,958	724,277	1	11,958,000	0.0606
3	AG-1 XL	121,391	8,066,118	4	30,347,750	0.0664
4	AG-1 XL TOU	41,350	2,720,799	2	20,675,000	0.0658
5	Total Commercial	12,372,493	1,377,821,918	125,579	98,524	0.1114
6						
7	442 Industrial and Irrigation					
8	E-30	58	17,486	72	806	0.3015
9	E-32 XS	43,615	7,736,718	2,654	16,434	0.1774
10	E-32 S	75,484	10,956,507	440	171,555	0.1452
11	E-32 M	189,644	23,108,491	297	638,532	0.1219
12	E-32 L	427,586	39,181,624	102	4,192,020	0.0916
13	E-32 TOU XS	249	34,230	8	31,125	0.1375
14	E-32 TOU S	1,295	145,811	3	431,667	0.1126
15	E-32 TOU M	2,420	333,330	4	605,000	0.1377
16	E-32 TOU L	45,278	4,601,325	11	4,116,182	0.1016
17	E-34	156,022	11,831,910	6	26,003,667	0.0758
18	E-35	723,288	50,411,801	14	51,663,429	0.0697
19	E-36 M	2,051	213,055	1	2,051,000	0.1039
20	E-36 XL	78,745	5,703,259	5	15,749,000	0.0724
21	E-47	714	176,844			0.2477
22	E-221	9,997	1,054,511	95	105,232	0.1055
23	EPR-6	23,619	2,784,845	23	1,026,913	0.1179
24	AG-1 M & L	1,020	121,712	2	510,000	0.1193
25	AG-1 XL TOU	413,900	21,527,240	2	206,950,000	0.0520
26	Special Contracts	88,052	7,590,089	5	17,610,400	0.0862
27	Total Industrial & Irrigation	2,283,037	187,530,788	3,744	609,786	0.0821
28						
29	444 Public Street Lighting	148,213	2,244,017	1,028	144,176	0.0151
30	Total Public Street Lighting	148,213	2,244,017	1,028	144,176	0.0151
31						
32	445 Other Public Authorities	2,822	187,560	154	18,325	0.0665
33	Total Other Public Authorities	2,822	187,560	154	18,325	0.0665
34						
35	Unbilled MWh & Revenue					
36	Residential Unbilled	17,477	-361,953			-0.0207
37	Commercial Unbilled	-8,340	-2,818,613			0.3380
38	Ind & Irrig. Unbilled	-7,505	-1,120,534			0.1493
39	Public Str Lighting Unbilled	16	214			0.0134
40	Other Public Auth Unbilled					
41	TOTAL Billed	27,948,843	3,290,313,800	1,172,568	23,836	0.1177
42	Total Unbilled Rev.(See Instr. 6)	1,648	-4,300,886	4,926	335	-2.6098
43	TOTAL	27,950,491	3,286,012,914	1,177,494	23,737	0.1176

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Total Unbilled Mwh & Revenue	1,648	-4,300,886			-2.6098
2						
3	449.1 Provision for Rate Refunds					
4	Residential PRR					
5	Commercial PRR					
6	Industrial & Irrigation PRR					
7	Public Street Lighting PRR					
8	Sales For Resale - Traditional					
9	Other Public Authorities PRR					
10	Total Provision for Rate Refunds					
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	27,948,843	3,290,313,800	1,172,568	23,836	0.1177
42	Total Unbilled Rev.(See Instr. 6)	1,648	-4,300,886	4,926	335	-2.6098
43	TOTAL	27,950,491	3,286,012,914	1,177,494	23,737	0.1176

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Aguila Irrigation District	RQ	86308	0.343	0.343	0.342
2	Buckeye Irrigation District	RQ	86306	0.214	0.214	0.214
3	City of Williams	RQ	MRT Vol 1	5.603	5.566	4.671
4	Electrical District No. 6	RQ	86307	0.000	0.000	0.000
5	Electrical District No. 7	RQ	86304	0.230	0.230	0.230
6	Electrical District No. 8	RQ	86310	3.971	3.971	3.971
7	Harquahala Valley Irrigation District	RQ	86309	1.447	1.447	1.447
8	Maricopa County Municipal Water Conser	RQ	86058	0.058	0.058	0.058
9	McMullen Valley Irrigiation District	RQ	86311	1.582	1.582	1.582
10	Roosevelt Irrigation District	RQ	86305	0.133	0.133	0.132
11	Tohono O'Odham Utility Authority	RQ	87975	8.571	8.571	6.974
12	Tonopah Irrigation District	RQ	86312	0.067	0.067	0.067
13	Town of Wickenburg	RQ	85726	0.001	0.001	0.001
14	Valley Electric Association	IF	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Overton Power District #5	LF	MRT Vol 3			
2	Arizona Electric Power Cooperative	SF	WSPP			
3	BP Energy Company	SF	WSPP			
4	Brookfield Energy Marketing LP	SF	WSPP			
5	California Independent Systems Operator	SF	MRT Vol 3			
6	Cargill Power Markets, LLC	SF	WSPP			
7	Citigroup Energy Inc.	SF	MRT Vol 3			
8	ConocoPhillips Company	SF	WSPP			
9	Constellation NewEnergy, Inc.	SF	WSPP			
10	Direct Energy Business, LLC	SF	WSPP			
11	EDF Trading North America LLC	SF	WSPP			
12	El Paso Electric Company	SF	WSPP			
13	Exelon Generation Company, LLC	SF	WSPP			
14	Freeport-McMoRan Copper & Gold Energy	SF	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Guzman Power Markets, LLC	SF	WSPP			
2	IBERDROLA Renewables, Inc.	SF	MRT Vol 3			
3	Idaho Power Company	SF	WSPP			
4	Imperial Irrigation District	SF	WSPP			
5	J. Aron & Company	SF	WSPP			
6	Los Angeles Dept of Water and Power	SF	WSPP			
7	Macquarie Energy LLC	SF	MRT Vol 3			
8	Morgan Stanley Capital Group, Inc.	SF	MRT Vol 3			
9	Nevada Power Company	SF	WSPP			
10	NextEra Energy Power Marketing, LLC	SF	WSPP			
11	Noble Americas Energy Solutions LLC	SF	WSPP			
12	PacifiCorp	SF	MRT Vol 3			
13	Powerex Corp.	SF	WSPP			
14	Public Service Co of New Mexico	SF	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Rainbow Energy Marketing Corporation	SF	WSPP			
2	Salt River Project	SF	WSPP			
3	Sempra Generation	SF	WSPP			
4	Shell Energy North America (US), L.P.	SF	MRT Vol 3			
5	Southern California Edison Company	SF	WSPP			
6	Talen Energy Marketing, LLC	SF	WSPP			
7	Tenaska Power Services Company	SF	WSPP			
8	TransAlta Energy Marketing, US, Inc.	SF	WSPP			
9	TransCanada Energy Sales, LTD	SF	WSPP			
10	Tri-State Generation and Transmission	SF	WSPP			
11	Tucson Electric Power Co.	SF	WSPP			
12	Twin Eagle Resource Management, LLC	SF	WSPP			
13	UNS Electric, Inc.	SF	WSPP			
14	WAPA, Colorado River Storage Project	SF	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	WAPA, Desert Southwest Region	SF	WSPP			
2	California Independent System Operator	OS	MRT Vol 3			
3	Direct Energy Business, LLC	OS	WSPP			
4	PacifiCorp Supplemental Coal	OS	RS # 182			
5	PacifiCorp Supplemental Other	OS	RS # 182			
6	Southwest Reserve Sharing Group	OS	SRSG1			
7	Transmission Losses	AD				
8	Change in Estimate	AD				
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,999	41,642	101,865	346,838	490,345	1
1,875	26,026	63,942	245,642	335,610	2
36,794	951,912	772,682	39,600	1,764,194	3
			30,361	30,361	4
2,014	27,971	67,851	392,575	488,397	5
33,991	471,189	1,155,691	1,806,896	3,433,776	6
12,583	175,886	430,887	688,336	1,295,109	7
499	7,018	16,809	404,150	427,977	8
13,970	196,119	476,859	688,285	1,361,263	9
1,165	16,102	39,238	404,975	460,315	10
43,851		2,596,322	491,710	3,088,032	11
575	8,091	19,373	165,783	193,247	12
12	172	406	154,901	155,479	13
15		1,050		1,050	14
150,328	1,922,128	5,741,925	5,860,052	13,524,105	
5,528,035	0	158,144,038	5,171,984	163,316,022	
5,678,363	**1,922,128**	**163,885,963**	**11,032,036**	**176,840,127**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
339,845		21,206,328		21,206,328	1
115,378		2,660,772		2,660,772	2
232,742		6,488,734		6,488,734	3
6,650		154,870		154,870	4
1,647,211		46,101,195		46,101,195	5
186,440		5,292,099		5,292,099	6
35,027		762,335		762,335	7
2,000		54,200		54,200	8
12		324		324	9
8		202		202	10
28,118		948,318		948,318	11
5,400		178,185		178,185	12
170,858		4,479,551		4,479,551	13
622		20,072		20,072	14
150,328	1,922,128	5,741,925	5,860,052	13,524,105	
5,528,035	0	158,144,038	5,171,984	163,316,022	
5,678,363	**1,922,128**	**163,885,963**	**11,032,036**	**176,840,127**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
6,313		209,484		209,484	1
45,200		1,403,316		1,403,316	2
33,846		1,045,016		1,045,016	3
65,764		1,854,518		1,854,518	4
188,400		4,668,088		4,668,088	5
1,408		43,646		43,646	6
42,203		1,103,427		1,103,427	7
483,865		11,959,537		11,959,537	8
14,780		418,690		418,690	9
4,810		112,690		112,690	10
174		4,338		4,338	11
274,397		6,381,655		6,381,655	12
63,110		1,466,077		1,466,077	13
45,713		1,322,081		1,322,081	14
150,328	1,922,128	5,741,925	5,860,052	13,524,105	
5,528,035	0	158,144,038	5,171,984	163,316,022	
5,678,363	**1,922,128**	**163,885,963**	**11,032,036**	**176,840,127**	

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
600		15,400		15,400	1
111,410		2,678,409		2,678,409	2
142,708		3,209,377		3,209,377	3
47,040		1,335,249		1,335,249	4
109,275		2,564,800		2,564,800	5
6,227		189,510		189,510	6
332,778		8,004,057		8,004,057	7
172,159		4,411,255		4,411,255	8
5,600		143,100		143,100	9
800		18,800		18,800	10
340,603		9,050,773		9,050,773	11
42,041		1,358,450		1,358,450	12
21,609		528,600		528,600	13
60,888		2,351,110		2,351,110	14
150,328	1,922,128	5,741,925	5,860,052	13,524,105	
5,528,035	0	158,144,038	5,171,984	163,316,022	
5,678,363	**1,922,128**	**163,885,963**	**11,032,036**	**176,840,127**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
8,112		295,442		295,442	1
7		-20,470		-20,470	2
3		60		60	3
24,450		399,572		399,572	4
56,380		1,269,746		1,269,746	5
5,036			115,680	115,680	6
			5,257,618	5,257,618	7
			-201,314	-201,314	8
					9
					10
					11
					12
					13
					14
150,328	1,922,128	5,741,925	5,860,052	13,524,105	
5,528,035	0	158,144,038	5,171,984	163,316,022	
5,678,363	**1,922,128**	**163,885,963**	**11,032,036**	**176,840,127**	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 310.4 Line No.: 2 Column: b

Represents NonFirm

Schedule Page: 310.4 Line No.: 3 Column: b

Represents NonFirm

Schedule Page: 310.4 Line No.: 4 Column: b

Represents NonFirm

Schedule Page: 310.4 Line No.: 5 Column: b

Represents NonFirm

Schedule Page: 310.4 Line No.: 6 Column: b

Represents NonFirm

Schedule Page: 310.4 Line No.: 6 Column: c

Rates are set per the Southwest Reserve Sharing Group participation agreement.

Schedule Page: 310.4 Line No.: 7 Column: b

Adjustment for transmission losses.

Schedule Page: 310.4 Line No.: 8 Column: a

The amounts shown on pages 310 and 311are actual amounts sold to companies during the reporting period. The change in estimate amount represents various timing differences between the accrued amounts for sales for resale compared to the actual amount.

Schedule Page: 310.4 Line No.: 8 Column: b

The amounts shown on pages 310 and 311are actual amounts sold to companies during the reporting period. The change in estimate amount represents various timing differences between the accrued amounts for sales for resale compared to the actual amount.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	14,158,948	13,091,699
5	(501) Fuel	273,234,222	313,774,272
6	(502) Steam Expenses	28,399,409	28,447,926
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,688,711	5,401,512
10	(506) Miscellaneous Steam Power Expenses	16,305,917	13,164,889
11	(507) Rents	1,263,460	1,344,400
12	(509) Allowances	7,439,715	3,880,172
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	346,490,382	379,104,870
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	8,094,353	7,972,993
16	(511) Maintenance of Structures	5,483,435	3,799,286
17	(512) Maintenance of Boiler Plant	40,944,344	51,427,942
18	(513) Maintenance of Electric Plant	8,863,236	14,168,312
19	(514) Maintenance of Miscellaneous Steam Plant	15,559,791	15,575,593
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	78,945,159	92,944,126
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	425,435,541	472,048,996
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	25,826,204	25,890,446
25	(518) Fuel	78,581,781	83,733,824
26	(519) Coolants and Water	13,082,524	12,317,679
27	(520) Steam Expenses	11,964,589	9,759,065
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	8,420,379	8,606,521
31	(524) Miscellaneous Nuclear Power Expenses	39,909,231	33,647,188
32	(525) Rents	45,199,895	45,367,801
33	TOTAL Operation (Enter Total of lines 24 thru 32)	222,984,603	219,322,524
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	6,008,938	8,092,140
36	(529) Maintenance of Structures	2,171,342	2,377,507
37	(530) Maintenance of Reactor Plant Equipment	14,171,173	12,504,993
38	(531) Maintenance of Electric Plant	16,342,376	15,826,106
39	(532) Maintenance of Miscellaneous Nuclear Plant	3,397,129	3,671,813
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	42,090,958	42,472,559
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	265,075,561	261,795,083
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,181,199	4,672,333
63	(547) Fuel	333,179,096	361,678,254
64	(548) Generation Expenses	7,661,080	7,841,540
65	(549) Miscellaneous Other Power Generation Expenses	54,658,422	55,181,306
66	(550) Rents	565,997	598,483
67	TOTAL Operation (Enter Total of lines 62 thru 66)	399,245,794	429,971,916
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	310,174	357,661
70	(552) Maintenance of Structures	1,601,118	800,851
71	(553) Maintenance of Generating and Electric Plant	27,779,648	27,426,301
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	4,351,060	4,971,094
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	34,042,000	33,555,907
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	433,287,794	463,527,823
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	410,042,292	422,679,819
77	(556) System Control and Load Dispatching	-4,144,485	-2,913,482
78	(557) Other Expenses	4,794,609	3,080,675
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	410,692,416	422,847,012
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,534,491,312	1,620,218,914
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,012,840	3,156,313
84			
85	(561.1) Load Dispatch-Reliability	2,536,052	2,347,786
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,505,276	2,082,930
87	(561.3) Load Dispatch-Transmission Service and Scheduling	870,424	760,826
88	(561.4) Scheduling, System Control and Dispatch Services	2,261,264	2,012,881
89	(561.5) Reliability, Planning and Standards Development	995,559	1,130,645
90	(561.6) Transmission Service Studies	120,381	144,238
91	(561.7) Generation Interconnection Studies	54,860	148,682
92	(561.8) Reliability, Planning and Standards Development Services	2,820,686	1,956,535
93	(562) Station Expenses	1,591,414	1,597,841
94	(563) Overhead Lines Expenses	2,452,456	2,102,625
95	(564) Underground Lines Expenses	60,874	81,810
96	(565) Transmission of Electricity by Others	25,848,955	27,191,422
97	(566) Miscellaneous Transmission Expenses	9,499,928	7,557,285
98	(567) Rents	7,550,709	7,498,643
99	TOTAL Operation (Enter Total of lines 83 thru 98)	62,181,678	59,770,462
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	577,318	569,389
102	(569) Maintenance of Structures	867,467	709,655
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment	164,338	164,443
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,925,411	5,115,203
108	(571) Maintenance of Overhead Lines	14,524,379	12,980,510
109	(572) Maintenance of Underground Lines	24,693	308,883
110	(573) Maintenance of Miscellaneous Transmission Plant	70,007	19,364
111	TOTAL Maintenance (Total of lines 101 thru 110)	21,153,613	19,867,447
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	83,335,291	79,637,909

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,803,283	4,841,222
135	(581) Load Dispatching	2,200,293	1,880,305
136	(582) Station Expenses	1,576,261	1,533,751
137	(583) Overhead Line Expenses	2,630,964	1,955,505
138	(584) Underground Line Expenses	1,797,421	1,707,195
139	(585) Street Lighting and Signal System Expenses	2,337	22,141
140	(586) Meter Expenses	5,616,656	5,537,027
141	(587) Customer Installations Expenses	680,181	-742,895
142	(588) Miscellaneous Expenses	32,083,855	34,068,083
143	(589) Rents	629,407	735,247
144	TOTAL Operation (Enter Total of lines 134 thru 143)	52,020,658	51,537,581
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,739,119	3,198,813
147	(591) Maintenance of Structures	252,338	1,202,145
148	(592) Maintenance of Station Equipment	3,383,396	2,085,061
149	(593) Maintenance of Overhead Lines	20,411,819	18,584,504
150	(594) Maintenance of Underground Lines	9,902,185	9,234,082
151	(595) Maintenance of Line Transformers	2,724,211	2,422,117
152	(596) Maintenance of Street Lighting and Signal Systems	539,741	727,857
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	3,495,143	3,236,446
155	TOTAL Maintenance (Total of lines 146 thru 154)	43,447,952	40,691,025
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	95,468,610	92,228,606
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,922,661	2,263,316
160	(902) Meter Reading Expenses	2,173,367	3,086,747
161	(903) Customer Records and Collection Expenses	44,012,091	42,902,342
162	(904) Uncollectible Accounts	4,073,429	3,942,074
163	(905) Miscellaneous Customer Accounts Expenses	273,867	349,460
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	52,455,415	52,543,939

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	308,352	573,659
168	(908) Customer Assistance Expenses	54,040,463	59,068,309
169	(909) Informational and Instructional Expenses	277,941	279,125
170	(910) Miscellaneous Customer Service and Informational Expenses	383,462	239,041
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	55,010,218	60,160,134
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	6,569,688	5,707,899
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	4,726,228	4,266,430
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	11,295,916	9,974,329
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	92,038,668	96,813,137
182	(921) Office Supplies and Expenses	9,150,693	10,138,062
183	(Less) (922) Administrative Expenses Transferred-Credit	22,860,000	22,370,000
184	(923) Outside Services Employed	37,023,948	25,038,368
185	(924) Property Insurance	5,201,486	5,438,796
186	(925) Injuries and Damages	7,566,536	8,907,704
187	(926) Employee Pensions and Benefits	52,261,312	75,334,711
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	16,926,157	17,228,362
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	3,572,429	8,390,441
192	(930.2) Miscellaneous General Expenses	-51,254,320	-51,466,697
193	(931) Rents	6,443,887	7,062,721
194	TOTAL Operation (Enter Total of lines 181 thru 193)	156,070,796	180,515,605
195	Maintenance		
196	(935) Maintenance of General Plant	11,677,723	11,601,954
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	167,748,519	192,117,559
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,999,805,281	2,106,881,390

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Dynegy Arlington - Tolling Agreement	RQ		257,035	N/A	N/A
2	Gila River Power - Tolling Agreement	RQ		173,748	N/A	N/A
3	Salt River Project	RQ		11,071	N/A	N/A
4	Citigroup Energy Inc.	LF		N/A	N/A	N/A
5	Morgan Stanley Capital Group, Inc.	LF		N/A	N/A	N/A
6	WAPA, Desert Southwest Region	LF		N/A	N/A	N/A
7	Ajo Improvement Co.	LF		N/A	N/A	N/A
8	Co-Generation	LF		N/A	N/A	N/A
9	Electrical District #5	LF		N/A	N/A	N/A
10	Net Inadvertent	LF		N/A	N/A	N/A
11	Citigroup Energy Inc.	IF		N/A	N/A	N/A
12	Morgan Stanley Capital Group, Inc.	IF		N/A	N/A	N/A
13	AG-1 Contracts	SF		N/A	N/A	N/A
14	Arizona Electric Power Cooperative	SF		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BP Energy Company	SF		N/A	N/A	N/A
2	Brookfield Energy Marketing LP	SF		N/A	N/A	N/A
3	California Independent System Operator	SF		N/A	N/A	N/A
4	California Independent System Operator	SF		N/A	N/A	N/A
5	Cargill Power Markets, LLC	SF		N/A	N/A	N/A
6	Central Arizona Water Conservation Dit	SF		N/A	N/A	N/A
7	EDF Trading North America LLC	SF		N/A	N/A	N/A
8	El Paso Electric Company	SF		N/A	N/A	N/A
9	Exelon Generation Company, LLC	SF		N/A	N/A	N/A
10	Guzman Power Markets, LLC	SF		N/A	N/A	N/A
11	IBERDROLA Renewables, Inc	SF		N/A	N/A	N/A
12	Idaho Power Company	SF		N/A	N/A	N/A
13	Imperial Irrigation District	SF		N/A	N/A	N/A
14	J. Aron & Company	SF		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Los Angeles Dept of Water & Power	SF		N/A	N/A	N/A
2	Macquarie Energy LLC	SF		N/A	N/A	N/A
3	Morgan Stanley Capital Group, Inc.	SF		N/A	N/A	N/A
4	Nevada Power Company	SF		N/A	N/A	N/A
5	Overton Power District #5	SF		N/A	N/A	N/A
6	PacifiCorp	SF		N/A	N/A	N/A
7	Portland General Electric Co.	SF		N/A	N/A	N/A
8	Powerex Corp.	SF		N/A	N/A	N/A
9	Public Service Co of New Mexico	SF		N/A	N/A	N/A
10	Rainbow Energy Marketing Corporation	SF		N/A	N/A	N/A
11	Salt River Project	SF		N/A	N/A	N/A
12	Sempra Generation	SF		N/A	N/A	N/A
13	Shell Energy North America (US), L.P.	SF		N/A	N/A	N/A
14	Southern California Edison	SF		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Talen Energy Marketing, LLC	SF		N/A	N/A	N/A
2	Tenaska Power Service Company	SF		N/A	N/A	N/A
3	TransAlta Energy Marketing, US, Inc.	SF		N/A	N/A	N/A
4	Tri-State Generation and Transmissio	SF		N/A	N/A	N/A
5	Tucson Electric Power Co	SF		N/A	N/A	N/A
6	Twin Eagle Resource Management, LLC	SF		N/A	N/A	N/A
7	UNS Electric, Inc.	SF		N/A	N/A	N/A
8	Vitol Inc.	SF		N/A	N/A	N/A
9	WAPA, Desert Southwest Region	SF		N/A	N/A	N/A
10	Aragonne Wind, LLC	LU		N/A	N/A	N/A
11	Arizona Solar One, LLC	LU		N/A	N/A	N/A
12	CE Turbo LLC	LU		N/A	N/A	N/A
13	Desert Sky Solar LLC	LU		N/A	N/A	N/A
14	Glendale Energy LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	High Lonesome Wind Ranch, LLC	LU		N/A	N/A	N/A
2	Novo BioPower LLC	LU		N/A	N/A	N/A
3	Perrin Ranch Wind LLC	LU		N/A	N/A	N/A
4	RE Ajo 1 LLC	LU		N/A	N/A	N/A
5	RE Bagdad Solar 1 LLC	LU		N/A	N/A	N/A
6	RE Gillespie 1, LLC	LU		N/A	N/A	N/A
7	SunE AZ 1 LLC	LU		N/A	N/A	N/A
8	SunE AZ 2 LLC	LU		N/A	N/A	N/A
9	Waste Management Renewable Energy, LLC	LU		N/A	N/A	N/A
10	Aguila Irrigation District	EX	141	N/A	N/A	N/A
11	Buckeye Water Conservation & Drainage	EX	155	N/A	N/A	N/A
12	City of Azusa Exchange	EX		N/A	N/A	N/A
13	Electric District #6	EX	126	N/A	N/A	N/A
14	Electric District #7	EX	128	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Electric District #8	EX	140	N/A	N/A	N/A
2	Harquahala Valley Power District	EX	153	N/A	N/A	N/A
3	Maricopa City Municipal Water Conservt	EX	168	N/A	N/A	N/A
4	McMullen Valley Water Conservt Dist	EX	142	N/A	N/A	N/A
5	PacifiCorp Exchange	EX	182	N/A	N/A	N/A
6	Roosevelt Irrigation District	EX	158	N/A	N/A	N/A
7	Tonopah Irrigation District	EX	143	N/A	N/A	N/A
8	AG-1 Contracts	OS		N/A	N/A	N/A
9	BP Energy Company	OS		N/A	N/A	N/A
10	Banked Energy	OS		N/A	N/A	N/A
11	California Independent System Operator	OS		N/A	N/A	N/A
12	Central Arizona Water Conservation Dit	OS		N/A	N/A	N/A
13	EDF Trading North America LLC	OS		N/A	N/A	N/A
14	Imperial Irrigation District	OS		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Los Angeles Dept of Water & Power	OS		N/A	N/A	N/A
2	Options and Hedges	OS		N/A	N/A	N/A
3	PacifiCorp	OS		N/A	N/A	N/A
4	Power Supply Adjuster	OS		N/A	N/A	N/A
5	Salt River Project	OS		N/A	N/A	N/A
6	San Diego Gas & Electric Co	OS		N/A	N/A	N/A
7	SFAS 133	OS		N/A	N/A	N/A
8	Southwest Reserve Sharing Group	OS		N/A	N/A	N/A
9	Tenaska Power Service Company	OS		N/A	N/A	N/A
10	WAPA, Desert Southwest Region	OS		N/A	N/A	N/A
11	Change in Estimate	AD		N/A	N/A	N/A
12	Various counterparties - prior yrs adt	AD		N/A	N/A	N/A
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,542,211			59,089,200			59,089,200	1
2,084,981			37,819,068		1,927,784	39,746,852	2
179,105			1,800,000	4,955,042		6,755,042	3
339,845				20,730,545		20,730,545	4
21,600				1,172,451		1,172,451	5
12				483,754		483,754	6
25							7
326							8
107							9
-3,846							10
20				1,099		1,099	11
1,000				61,740		61,740	12
1,158,180				41,202,717		41,202,717	13
5,835				230,540		230,540	14
7,772,414	796,496	953,698	98,708,268	261,617,529	49,716,495	410,042,292	

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,866				401,766		401,766	1
271				9,315		9,315	2
					4,238,173	4,238,173	3
74,987				2,445,501		2,445,501	4
6,862				220,765		220,765	5
330				10,560		10,560	6
57,837				2,587,607		2,587,607	7
2,960				68,667		68,667	8
1,712				60,196		60,196	9
824				26,897		26,897	10
800				29,600		29,600	11
4,150				62,000		62,000	12
3,277				75,386		75,386	13
7,600				249,300		249,300	14
7,772,414	796,496	953,698	98,708,268	261,617,529	49,716,495	410,042,292	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
5,527				259,945		259,945	1
1,296				46,586		46,586	2
7,074				296,261		296,261	3
31,205				1,198,807		1,198,807	4
330				20,592		20,592	5
55,909				1,609,369		1,609,369	6
1,300				68,800		68,800	7
15,333				1,116,646		1,116,646	8
9,274				244,243		244,243	9
200				2,600		2,600	10
21,038				851,189		851,189	11
4,440				136,340		136,340	12
152,455				4,369,494		4,369,494	13
626				13,313		13,313	14
7,772,414	796,496	953,698	98,708,268	261,617,529	49,716,495	410,042,292	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
20,250				491,204		491,204	1
14,426				418,951		418,951	2
15,217				601,627		601,627	3
960				45,600		45,600	4
8,482				234,002		234,002	5
8,400				310,200		310,200	6
1,318				33,884		33,884	7
400				16,000		16,000	8
74				1,225		1,225	9
236,859				14,204,224		14,204,224	10
718,834				91,961,151		91,961,151	11
73,864				5,378,297		5,378,297	12
39,708				3,397,017		3,397,017	13
19,306				1,611,112		1,611,112	14
7,772,414	796,496	953,698	98,708,268	261,617,529	49,716,495	410,042,292	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
243,521				14,508,620		14,508,620	1
100,901				9,381,687		9,381,687	2
191,913				16,168,670		16,168,670	3
9,231				1,226,789		1,226,789	4
34,116				5,106,483		5,106,483	5
42,787				4,082,308		4,082,308	6
25,621				3,253,712		3,253,712	7
35,828				4,043,889		4,043,889	8
22,855				1,878,452		1,878,452	9
	2,606	1,918					10
	1,723	1,392					11
	175,475	324,347		-2,491,943		-2,491,943	12
	493	467					13
	1,341	5,084					14
7,772,414	796,496	953,698	98,708,268	261,617,529	49,716,495	410,042,292	

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	26,058	16,246					1
	2,963	5,408					2
	4,282	9,103					3
	6,563	8,905					4
	571,373	571,030		-2,107,788		-2,107,788	5
	2,793	5,045					6
	826	4,753					7
44,210				897,530		897,530	8
1				14		14	9
					5,810,800	5,810,800	10
2				20,010	1,675,303	1,695,313	11
310				10,700		10,700	12
33,600				873,600		873,600	13
7,868				295,603		295,603	14
7,772,414	796,496	953,698	98,708,268	261,617,529	49,716,495	410,042,292	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
790				15,800		15,800	1
					22,007,200	22,007,200	2
75				2,100		2,100	3
					19,505,567	19,505,567	4
10				220		220	5
2,431				91,903		91,903	6
					-4,691,981	-4,691,981	7
1,626				86,166		86,166	8
165				3,536		3,536	9
8,571				245,341		245,341	10
					-847,231	-847,231	11
					90,880	90,880	12
							13
							14
7,772,414	796,496	953,698	98,708,268	261,617,529	49,716,495	410,042,292	

Name of Respondent Arizona Public Service Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 3 Column: a

Eastern Area

Schedule Page: 326.5 Line No.: 8 Column: b

Represents nonfirm

Schedule Page: 326.5 Line No.: 9 Column: b

Represents nonfirm

Schedule Page: 326.5 Line No.: 10 Column: b

Represents nonfirm

Schedule Page: 326.5 Line No.: 11 Column: b

Represents nonfirm

Schedule Page: 326.5 Line No.: 12 Column: b

Represents nonfirm

Schedule Page: 326.5 Line No.: 13 Column: b

Represents nonfirm

Schedule Page: 326.5 Line No.: 14 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 1 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 2 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 3 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 4 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 5 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 6 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 7 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 8 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 9 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 10 Column: b

Represents nonfirm

Schedule Page: 326.6 Line No.: 11 Column: a

The amount shown on pages 326 and 327 are actual amounts purchased from counterparties during the reporting period. The change in estimate amount represents various timing differences between the accrued amounts for purchased power compared to the actual amount.

Schedule Page: 326.6 Line No.: 11 Column: b

The amount shown on pages 326 and 327 are actual amounts purchased from counterparties during the reporting period. The change in estimate amount represents various timing differences between the accrued amounts for purchased power compared to the actual amount.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Arizona Public Service	Various	Various	FNS
2	Arizona Public Service	Pinnacle West Capital Company	Arizona Public Service Co.	FNS
3	Arizona Public Service	Arizona Public Service Co.	Arizona Public Service Co.	FNS
4	Arizona Public Service	Various	Arizona Public Service Co.	FNS
5	Ajo Improvement Company	Arizona Public Service Co.	Ajo Improvement	FNO
6	Central Arizona Water Conservation District	Salt River Project	Central Arizona Project	FNO
7	Navajo Tribal Utility Authority	Tucson Electric Power	Navajo Tribal Utility Auth	FNO
8	Public Service Company of New Mexico	Various	Various	FNO
9	Southwest Transmission Cooperative	Various	Various	FNO
10	Electrical District 3	Various	Various	FNO
11	EDF Trading North America, LLC	Not Available	Not Available	LFP
12	Electrical District 3	Not Available	Not Available	LFP
13	CSE Operating 1, LLC	Not Available	Not Available	LFP
14	NOVO BioPower LLC	Not Available	Not Available	LFP
15	PacifiCorp	Not Available	Not Available	LFP
16	Public Service Company of New Mexico	Not Available	Not Available	LFP
17	Salt River Project	Not Available	Not Available	LFP
18	Salt River Project (OATT General Srvs)	Not Available	Not Available	LFP
19	Arizona Public Service Company	Not Available	Not Available	SFP
20	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	SFP
21	City of Aneheim	Not Available	Not Available	SFP
22	EDF Trading North America, LLC	Not Available	Not Available	SFP
23	Iberdrola Renewables	Not Available	Not Available	SFP
24	Macquire Energy LLC	Not Available	Not Available	SFP
25	PacifiCorp	Not Available	Not Available	SFP
26	Powerex	Not Available	Not Available	SFP
27	Public Service Company of New Mexico	Not Available	Not Available	SFP
28	Salt River Project	Not Available	Not Available	SFP
29	Salt River Project (OATT General Service)	Not Available	Not Available	SFP
30	Sempra Generation	Not Available	Not Available	SFP
31	Shell Energy North America LP	Not Available	Not Available	SFP
32	Sundevil Power Holdings	Not Available	Not Available	SFP
33	Tenaska Power Services Co.	Not Available	Not Available	SFP
34	TransAlta Energy Marketing U.S. Inc	Not Available	Not Available	SFP
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Tucson Electric Power Company	Not Available	Not Available	SFP
2	Yuma Cogeneration Associates	Not Available	Not Available	SFP
3	Arizona Public Service Company	Not Available	Not Available	NF
4	Arizona Electric Power Cooperative, Inc	Not Available	Not Available	NF
5	Cargill Power Markets, LLC	Not Available	Not Available	NF
6	City of Anaheim	Not Available	Not Available	NF
7	EDF Trading North America, LLC	Not Available	Not Available	NF
8	El Paso Electric Co	Not Available	Not Available	NF
9	Iberdrola Renewables	Not Available	Not Available	NF
10	Imperial Irrigation District	Not Available	Not Available	NF
11	Macquire Energy LLC	Not Available	Not Available	NF
12	Mag Energy Solutions, Inc	Not Available	Not Available	NF
13	Morgan Stanley	Not Available	Not Available	NF
14	Nevada Power Company	Not Available	Not Available	NF
15	NV Energy	Not Available	Not Available	NF
16	PacifiCorp	Not Available	Not Available	NF
17	Powerex	Not Available	Not Available	NF
18	Public Service Company of New Mexico	Not Available	Not Available	NF
19	Pudget Sound Energy Inc	Not Available	Not Available	NF
20	Salt River Project	Not Available	Not Available	NF
21	Salt River Project (OATT General Service)	Not Available	Not Available	NF
22	Sempra Generation	Not Available	Not Available	NF
23	Shell Energy North America LP	Not Available	Not Available	NF
24	Southern California Edison Company	Not Available	Not Available	NF
25	Tenaska Power Services Co.	Not Available	Not Available	NF
26	TransAlta Energy Marketing U.S Inc.	Not Available	Not Available	NF
27	Tucson Electric Power Company	Not Available	Not Available	NF
28	WestConnect	Not Available	Not Available	NF
29	Yuma Cogeneration Associates	Yuma Cogeneration Assoc.	San Diego Gas and Elect.	NF
30	Arizona Public Service Company	Not Available	Not Available	OLF
31	Imperial Irrigation District	Not Available	Not Available	OS
32	Luke AFB Main Field	DOE WAPA Lower	Luke Air Force Base	OS
33	Marine Corps. Air Station	DOE WAPA Lower	Marine Corp Air Station	OS
34	NOVO BioPower LLC	Not Available	Not Available	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PacifiCorp	Not Available	Not Available	OLF
2	Public Service Company of New Mexico	Public Serv of New Mexico	Public Serv of New Mexico	OLF
3	Salt River Project (Schedule F)	Salt River Project	Salt River Project	OS
4	Salt River Project (Schedule Q)	Pinnacle Peak	Ocotillo 230	OS
5	Tucson Electric Power Company	Tucson Electric Power	Tucson Electric Power	OLF
6	Unit B Irrigation and Drainage District	Arizona Power Authority	Unit B Irrigation District	OS
7	Western Area Power Administration (DSW)	Not Available	Not Available	OLF
8	Yuma Cogeneration Associates	Yuma Cogeneration Assoc.	San Diego Gas and Elect.	OLF
9	Yuma Mesa Irrigation and Drainage District	DOE WAPA Lower	Yuma-Mesa Irrigation Dist	OS
10	Other	Not Available	Not Available	AD
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
OATT	Various	Various		887,126	887,126	1
OATT	Various	Various		29,506,158	29,506,158	2
OATT	Various	Various				3
OATT	Various	Various				4
OATT	Cholla	Ajo Customers	3	14,181	14,181	5
OATT	West Wing Substation	Various	45	325,379	325,379	6
OATT	Various	Various	4	54,111	54,111	7
OATT	Various	Various	56	649,571	649,571	8
OATT	Various	Various	5	21,232	21,232	9
OATT	Various	Various	170	460,563	460,563	10
OATT	N/A	N/A	3			11
OATT	Various	Various	90	134,291	134,291	12
OATT	Various	Various	1	4,365	4,365	13
OATT	Various	Various	14	110,721	110,721	14
OATT	Various	Various	37	206,039	206,039	15
OATT	Various	Various	10	77,968	77,968	16
OATT	Various	Various	275	214,998	214,998	17
OATT	Various	Various	280	560,952	560,952	18
OATT	Various	Various	8,648	41,569	41,569	19
OATT	Various	Various	1,725	6,919	6,919	20
OATT	Various	Various	6,952	239,973	239,973	21
OATT	Various	Various	3,420	4,130	4,130	22
OATT	Various	Various	80	139	139	23
OATT	Various	Various	1,442	1,382	1,382	24
OATT	Various	Various	22,726	69,820	69,820	25
OATT	Various	Various	1,899	5,497	5,497	26
OATT	Various	Various	4,678	15,425	15,425	27
OATT	Various	Various	384	452	452	28
OATT	Various	Various	2,685	20,109	20,109	29
OATT	Various	Various	275	526	526	30
OATT	Various	Various	200	200	200	31
OATT	Various	Various	3,894	8,337	8,337	32
OATT	Various	Various	3,142	5,571	5,571	33
OATT	Various	Various	219	489	489	34
			219,020	**42,282,561**	**42,261,873**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
OATT	Various	Various	82,955	141,220	141,220	1
OATT	Various	Various	44	29	29	2
OATT	Various	Various	4,015	56,175	56,175	3
OATT	Various	Various	234	744	744	4
OATT	Various	Various	1,959	2,853	2,853	5
OATT	Various	Various	5,919	8,257	8,257	6
OATT	Various	Various	788	163	163	7
OATT	Various	Various	142	125	125	8
OATT	Various	Various	119	178	178	9
OATT	Various	Various	72	36	36	10
OATT	Various	Various	670	1,313	1,313	11
OATT	Various	Various	40	41	41	12
OATT	Various	Various	4,530	8,850	8,850	13
OATT	Various	Various	200	1,100	1,100	14
OATT	Various	Various	204	329	329	15
OATT	Various	Various	19,313	62,071	62,071	16
OATT	Various	Various	1,192	2,157	2,157	17
OATT	Various	Various	1,174	3,722	3,722	18
OATT	Various	Various	1			19
OATT	Various	Various	944	1,281	1,281	20
OATT	Various	Various	4,518	86,894	86,894	21
OATT	Various	Various	515	575	575	22
OATT	Various	Various	519	641	641	23
OATT	Various	Various	1,515	1,525	1,525	24
OATT	Various	Various	449	1,851	1,851	25
OATT	Various	Various	1,613	8,185	8,185	26
OATT	Various	Various	21,620	65,662	65,662	27
Tariff Volume 6	Various	Various		6,620	6,620	28
OATT	Various	Various	113	94	94	29
RS 183	Not Available	Not Available		378,733	378,733	30
OATT	Not Available	Not Available				31
RS 162	Pinnacle Peak Sub	Luke Substation				32
RS 166	Gila Substation	Marine Corp Air Stn				33
OATT	Not Available	Not Available				34
			219,020	**42,282,561**	**42,261,873**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
RS 183	Not Available	Not Available	130	6,335,077	6,335,077	1
RS 73	Palo Verde	Four Corners		855,861	855,861	2
RS 3	West Phoenix Sub	West Phoenix Sub	100			3
RS 3	Pinnacle Peak	Ocotillo 230				4
RS 32	Four Corners	Saguaro Plant	51	601,903	581,215	5
RS 181	Gila Substation	District Customer				6
RS 33	Not Available	Not Available		103	103	7
RS 198	Riverside Substation	North Gila Sub				8
RS 31	Gila Substation	Yuma Mesa Load				9
NA	Not Available	Not Available				10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			219,020	**42,282,561**	**42,261,873**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		8,631,657	8,631,657	1
		-8,631,657	-8,631,657	2
		-263,883,812	-263,883,812	3
		263,883,812	263,883,812	4
95,614	-43,705	-376	51,533	5
1,435,556		-10,633	1,424,923	6
266,885	-55,091	52,643	264,437	7
2,012,086		36,624	2,048,710	8
158,956		10,339	169,295	9
2,777,095	-324,653	-23,683	2,428,759	10
8,978			8,978	11
1,911,943	344,199		2,256,142	12
22,882	4,841	60,961	88,684	13
506,935		-3,377	503,558	14
1,339,573		-1,602	1,337,971	15
362,047		-2,419	359,628	16
2,469,019			2,469,019	17
7,608,433		-12,421	7,596,012	18
279,379		193,783	473,162	19
37,587			37,587	20
1,834,666		-8,376	1,826,290	21
79,824		143,584	223,408	22
1,053			1,053	23
10,102		-4	10,098	24
523,693		-18,893	504,800	25
44,074		-166	43,908	26
167,826		403,555	571,381	27
2,890			2,890	28
71,970			71,970	29
2,170		-3	2,167	30
820			820	31
81,458			81,458	32
36,440		-14	36,426	33
3,973		-95	3,878	34
32,230,440	**-73,365**	**2,611,159**	**34,768,234**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,562,829		-1,754	1,561,075	1
327		-9	318	2
298,746		67,161	365,907	3
4,580			4,580	4
21,992		-18	21,974	5
53,164			53,164	6
6,984		10,123	17,107	7
979		20,242	21,221	8
1,617		-19	1,598	9
536		7,970	8,506	10
11,275		-10	11,265	11
305			305	12
60,568		-81	60,487	13
12,651		-12	12,639	14
2,030			2,030	15
283,004			283,004	16
17,504		-315	17,189	17
24,370		-80,298	-55,928	18
7			7	19
12,400		8,168	20,568	20
98,258		5,468	103,726	21
3,790		-28	3,762	22
4,740		-45	4,695	23
13,770		-33	13,737	24
11,822		-164	11,658	25
50,129		-302	49,827	26
478,764		1,766	480,530	27
				28
1,113		229	1,342	29
				30
4,416		48,581	52,997	31
173,579	1,044		174,623	32
77,652			77,652	33
		2,716	2,716	34
32,230,440	**-73,365**	**2,611,159**	**34,768,234**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
1,415,030			1,415,030	2
23,352			23,352	3
		1,112,647	1,112,647	4
1,824,000			1,824,000	5
540			540	6
				7
1,515,190			1,515,190	8
4,500			4,500	9
		589,749	589,749	10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
32,230,440	**-73,365**	**2,611,159**	**34,768,234**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: a
Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 1 Column: m
Intracompany Transmission

Schedule Page: 328 Line No.: 2 Column: a
Service to Arizona Public Service Company pursuant to Part III of the OATT

Schedule Page: 328 Line No.: 2 Column: m
Intracompany Transmission

Schedule Page: 328 Line No.: 3 Column: a
Service to Arizona Public Service Company pursuant to Part IV of the OATT

Schedule Page: 328 Line No.: 3 Column: m
Intracompany Transmission

Schedule Page: 328 Line No.: 4 Column: a
Service to Arizona Public Service Company pursuant to Part IV of the OATT

Schedule Page: 328 Line No.: 4 Column: m
Intracompany Transmission

Schedule Page: 328 Line No.: 5 Column: m
Unreserved use credit

Schedule Page: 328 Line No.: 6 Column: m
Unreserved use credit

Schedule Page: 328 Line No.: 7 Column: m
Direct assignment charges and unreserved use credit

Schedule Page: 328 Line No.: 8 Column: m
Unreserved use credit and penalty

Schedule Page: 328 Line No.: 9 Column: m
Unreserved use credit and penalty

Schedule Page: 328 Line No.: 10 Column: m
Unreserved use credit

Schedule Page: 328 Line No.: 11 Column: d
Termination 2/1/2015

Schedule Page: 328 Line No.: 12 Column: d
Termination date 5/31/2025

Schedule Page: 328 Line No.: 13 Column: d
Termination date 5/15/2020

Schedule Page: 328 Line No.: 13 Column: m
Direct assignment charges and unreserved use credit

Schedule Page: 328 Line No.: 14 Column: d
10 MW Terminates 1/1/2028 and 4 MW Terminates 10/1/2031

Schedule Page: 328 Line No.: 14 Column: m
Unreserved use credit

Schedule Page: 328 Line No.: 15 Column: d
Termination date 7/15/2041

Schedule Page: 328 Line No.: 15 Column: m
Unreserved use credit

Schedule Page: 328 Line No.: 16 Column: d
Can renew annually

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 16 Column: m

Unreserved use credit

Schedule Page: 328 Line No.: 17 Column: d

Termination date - Not yet determined when this control area will be transferred. Once, Determined, APS will provide written notice to the transmission customer.

Schedule Page: 328 Line No.: 18 Column: d

Termination date - Not yet determined when this control area will be transferred. Once, Determined, APS will provide written notice to the transmission customer.

Schedule Page: 328 Line No.: 18 Column: m

Unreserved use credit and penalty

Schedule Page: 328 Line No.: 19 Column: a

APS Merchant is an affiliate of Arizona Public Service Company

Schedule Page: 328 Line No.: 19 Column: m

Unreserved use penalty

Schedule Page: 328 Line No.: 21 Column: m

Unreserved use credit

Schedule Page: 328 Line No.: 22 Column: m

Unreserved use credit and penalty

Schedule Page: 328 Line No.: 24 Column: m

Unreserved use credit

Schedule Page: 328 Line No.: 25 Column: m

Out of period adjustment and unreserved use credit

Schedule Page: 328 Line No.: 26 Column: m

Unreserved use credit

Schedule Page: 328 Line No.: 27 Column: m

Unreserved use penalty

Schedule Page: 328 Line No.: 30 Column: m

Unreserved use credit

Schedule Page: 328 Line No.: 33 Column: m

Unreserved use credit

Schedule Page: 328 Line No.: 34 Column: m

Unreserved use credit

Schedule Page: 328.1 Line No.: 1 Column: m

Unreserved use penalty

Schedule Page: 328.1 Line No.: 2 Column: m

Unreserved use credit

Schedule Page: 328.1 Line No.: 3 Column: a

APS Merchant is an affiliate of Arizona Public Service Company

Schedule Page: 328.1 Line No.: 3 Column: m

Unreserved use penalty

Schedule Page: 328.1 Line No.: 5 Column: m

Unreserved use credit

Schedule Page: 328.1 Line No.: 7 Column: m

Unreserved use penalty

Schedule Page: 328.1 Line No.: 8 Column: m

Unreserved use penalty

Schedule Page: 328.1 Line No.: 9 Column: m

Unreserved use credit

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 328.1 Line No.: 10 Column: m
Unreserved use penalty

Schedule Page: 328.1 Line No.: 11 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 13 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 14 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 17 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 18 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 20 Column: m
Unreserved use penalty

Schedule Page: 328.1 Line No.: 21 Column: m
Unreserved use penalty

Schedule Page: 328.1 Line No.: 22 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 23 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 24 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 25 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 26 Column: m
Unreserved use credit

Schedule Page: 328.1 Line No.: 27 Column: m
Unreserved use penalty

Schedule Page: 328.1 Line No.: 28 Column: n
Regional pricing

Schedule Page: 328.1 Line No.: 29 Column: m
Unreserved use penalty

Schedule Page: 328.1 Line No.: 30 Column: a
APS Merchant is an affiliate of Arizona Public Service Company

Schedule Page: 328.1 Line No.: 30 Column: d
Termination date 10/31/2020

Schedule Page: 328.1 Line No.: 30 Column: n
Exchange agreement pursuant to Pre888 contract

Schedule Page: 328.1 Line No.: 31 Column: d
Terminates upon mutual agreement

Schedule Page: 328.1 Line No.: 31 Column: m
Direct assignment charges

Schedule Page: 328.1 Line No.: 32 Column: d
Termination date 10 years or longer with a three year termination notice by either party.

Schedule Page: 328.1 Line No.: 33 Column: d
Termination date - Indefinite term subject to a three year termination notice by either party.

Schedule Page: 328.1 Line No.: 34 Column: d
Termination date 1/1/2028

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 328.1 Line No.: 34 Column: m

Direct assignment charges

Schedule Page: 328.2 Line No.: 1 Column: d

Termination date 10/31/2020

Schedule Page: 328.2 Line No.: 1 Column: n

Exchange agreement pursuant to Pre888 contract

Schedule Page: 328.2 Line No.: 2 Column: d

Termination date - Good until terminated with thirty days advance written notice if no service schedule is in effect or scheduled to become effective.

Schedule Page: 328.2 Line No.: 3 Column: d

Termination date - Good until terminated with a three year advance written notice.

Schedule Page: 328.2 Line No.: 4 Column: d

Schedule Q is for transmission but the cost is based on the plant investment of Pinnacle Peak-Ocotillo 230kV lines and not the current transmission rates.

Schedule Page: 328.2 Line No.: 4 Column: m

Direct assignment charges (O&M/Lease payment)

Schedule Page: 328.2 Line No.: 5 Column: d

Termination date - Good until terminated by May 31st of any year with three years advance written notice.

Schedule Page: 328.2 Line No.: 6 Column: d

Termination date - indefinite term subject to three year termination notice by either party.

Schedule Page: 328.2 Line No.: 7 Column: d

Termination date 6/1/2046. Subject to three year termination notice.

Schedule Page: 328.2 Line No.: 7 Column: n

Exchange agreement pursuant to Pre888 contract

Schedule Page: 328.2 Line No.: 8 Column: d

Termination date 12/31/2024

Schedule Page: 328.2 Line No.: 9 Column: d

Termination date 2/3/1997 - Automatic five year renewal subject to a three year termination notice by either party.

Schedule Page: 328.2 Line No.: 10 Column: d

FERC transmission rate true up, change in estimate, and timing difference.

Schedule Page: 328.2 Line No.: 10 Column: m

FERC transmission rate true up, change in estimate, and timing difference.

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	LFP			839,070			839,070
2	Bureau of Indian Affair	OLF			143,600			143,600
3	Department of Energy	OS	9,094	9,094		208,801	7,162	215,963
4	Department of Energy	OS	124,337	124,337	272,022	175,552	2,623	450,197
5	Department of Energy	FNS	312,155	312,155	934,325	519,467	-24,491	1,429,301
6	Department of Energy	OS	1,143,170	1,143,170	3,632,493	879,931	-104,593	4,407,831
7	Department of Energy	LFP	543,234	543,234	50,505	409,718	63,628	523,851
8	Department of Energy	LFP	112,305	112,305	1,446,319	339,750	505,826	2,291,895
9	Department of Energy	LFP	62,855	62,855	6,602,639	49,418	2,589	6,654,646
10	Department of Energy	FNS			92,066			92,066
11	Department of Energy	OS	160,745	160,745	289,369	2,639	1	292,009
12	Electric District # 3	LFP	2,583	2,583	82,363		-1,184	81,179
13	Electric District # 4	OLF	466	466	14,064		17,619	31,683
14	Salt River Project	OLF	39,694	39,694	182,078	31,272	-29,774	183,576
15	Salt River Project	OLF	339,432	339,432	1,306,785	267,511	-267,511	1,306,785
16	Salt River Project	LFP	177,735	177,735	1,230,153	142,797	-1,960	1,370,990
	TOTAL		5,419,454	5,419,454	21,651,190	4,281,551	-83,786	25,848,955

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Salt River Project	FNS	485,396	485,396	1,918,785	385,789	-3,624	2,300,950
2	Salt River Project	OLF	107,915	107,915	238,498	86,224	-351,036	-26,314
3	Salt River Project	OS	1,716,132	1,716,132		449,095	97,367	546,462
4	Salt River Project	FNS	371	371	1,784,755	302,754	-34,308	2,053,201
5	Salt River Project	OS				3,700		3,700
6	Southern Cal Edison	LFP	101	101	179,297		21,230	200,527
7	Southwester Transmissio	SFP	43,951	43,951	175,040		4,709	179,749
8	Tucson Electric Power	OS	286	286	1,698	100	2,064	3,862
9	Public Srvs Co of NM	NF	800	800	79,817	404		80,221
10	SRP Misc AR	OS	36,697	36,697	155,449	26,629	9,877	191,955
11								
12								
13								
14								
15								
16								
	TOTAL		5,419,454	5,419,454	21,651,190	4,281,551	-83,786	25,848,955

Name of Respondent Arizona Public Service Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: a

Intercompany Transmission

Schedule Page: 332 Line No.: 1 Column: b

Terminates December 31, 2015

Schedule Page: 332 Line No.: 2 Column: b

Teminates with 30 days notice

Schedule Page: 332 Line No.: 3 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 4 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 5 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 6 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 7 Column: b

Terminates September 30, 2029

Schedule Page: 332 Line No.: 7 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 8 Column: b

Terminates May 1, 2022

Schedule Page: 332 Line No.: 8 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 9 Column: b

Terminates December 31, 2017

Schedule Page: 332 Line No.: 9 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 10 Column: b

Terminates September 30, 2029

Schedule Page: 332 Line No.: 11 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 12 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 13 Column: b

Effective until terminated by counterparty

Schedule Page: 332 Line No.: 13 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 14 Column: b

Terminates with 1 year APS notice or 5 year SRP notice

Schedule Page: 332 Line No.: 14 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 15 Column: b

Terminates with 5 year notice

Schedule Page: 332 Line No.: 15 Column: g

Prior period adjustment /Timing

Schedule Page: 332 Line No.: 16 Column: b

Terminates May 1, 2019

Schedule Page: 332 Line No.: 16 Column: g

Name of Respondent Arizona Public Service Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 1 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 1 Column: h

APS payment as a credit on APS provides SRP in the same contract

Schedule Page: 332.1 Line No.: 2 Column: b

Terminates with 1 year notice

Schedule Page: 332.1 Line No.: 2 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 3 Column: b

Loss compensation for deliveries to DV

Schedule Page: 332.1 Line No.: 3 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 4 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 6 Column: b

Terminates September 30, 2037

Schedule Page: 332.1 Line No.: 6 Column: g

Ancilliary/Timing

Schedule Page: 332.1 Line No.: 7 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 8 Column: g

Prior period adjustment /Timing

Schedule Page: 332.1 Line No.: 10 Column: g

Prior period adjustment /Timing

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	970,388
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	13,443
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,423,757
6	Allocation of Parent Company Costs	9,235,597
7	Bank Fees	750,267
8	Billed to Others-Services Performed	-64,872,491
9	Communication Service	282,359
10	Materials & Supplies	41,743
11	Miscellaneous Payroll	-86,534
12	Outside Services	616,440
13	Rents/Leases	54,448
14	Transportation Expense	12,384
15	Travel	303,879
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	-51,254,320

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			57,569,607		57,569,607
2	Steam Production Plant	55,014,425	2,102,978	2,135		57,119,538
3	Nuclear Production Plant	58,056,969	-2,173,590	2,257,519		58,140,898
4	Hydraulic Production Plant-Conventional	-441,067				-441,067
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	69,267,330	140,689			69,408,019
7	Transmission Plant	43,894,009		4,067,809		47,961,818
8	Distribution Plant	124,145,279		927,403		125,072,682
9	Regional Transmission and Market Operation					
10	General Plant	35,465,416		5,922,645		41,388,061
11	Common Plant-Electric					
12	TOTAL	385,402,361	70,077	70,747,118		456,219,556

B. Basis for Amortization Charges

RATES

Franchises	302	4.00%
Software	303	10.00% - 33.33%
Misc. Intangibles	303.0	2.08% - 20.00%
Limited Term Land Rights	310 / 350 / 360 / 389	1.67% - 50.00%
Office Equipment & Furniture, Small Tools, Garage Equipment, Misc. Equipment	391 / 391.2 / 393 / 394 / 395 / 398	4.17% - 5.00%
Leasehold Improvements	321 / 322 / 323 / 324 / 325 / 326 / 371 / 390 / 397	amortized over the life of the lease

* Note: Hydro expense relates to the Childs Irving Regulatory Liability balance being amorted over 3 years to clear the Regulatory "2540" balance upon final decommissioning per ACC Dec. 73183.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	ACC/RUCO Expenses				
2	Annual Assessment by Arizona Corporation				
3	Commission (ACC) and Annual Assessment by				
4	Residential Utility Consumer Office (RUCO)	7,545,289		7,545,289	
5	Legal and Filing Fees		3,520	3,520	
6	Consulting Fees		18,649	18,649	
7	Payroll and Employee Expense		1,795,018	1,795,018	
8	Est. ACC and RUCO Assessments on Unbilled Rev	-70,532		-70,532	
9	Other				
10					
11	FERC Expenses				
12	Regulatory Assessment by FERC	2,347,758		2,347,758	
13	Legal and Filing Fees				
14	Consulting Fees		3,291	3,291	
15	Payroll and Employee Expenses		189,888	189,888	
16	Other				
17					
18	NRC Expenses				
19	NRC License Fees	5,093,276		5,093,276	
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	14,915,791	2,010,366	16,926,157	

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
							46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)e	RENEWABLES
2	A(1)e	HPS
3	B(1)	EPRI
4	B(1)	EPRI
5	B(1)	EPRI
6	B(1)	EPRI
7	B(1)	EPRI
8	B(1)	EPRI
9	B(1)	EPRI
10	Total	
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
	410,740	5490	410,740		1
49,585		5880	49,585		2
	861,911	1070	861,911		3
	526,034	5000	526,034		4
	129,208	5060	129,208		5
	937,715	5240	937,715		6
	379,390	5490	379,390		7
	712,731	5800	712,731		8
	23,716	9200	23,716		9
49,585	3,981,445		4,031,030		10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	121,903,047		
4	Transmission	16,731,259		
5	Regional Market			
6	Distribution	38,168,170		
7	Customer Accounts	27,814,848		
8	Customer Service and Informational	2,038,431		
9	Sales	6,872,764		
10	Administrative and General	87,825,852		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	301,354,371		
12	Maintenance			
13	Production	45,801,822		
14	Transmission	3,876,707		
15	Regional Market			
16	Distribution	23,966,563		
17	Administrative and General	4,070,462		
18	TOTAL Maintenance (Total of lines 13 thru 17)	77,715,554		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	167,704,869		
21	Transmission (Enter Total of lines 4 and 14)	20,607,966		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	62,134,733		
24	Customer Accounts (Transcribe from line 7)	27,814,848		
25	Customer Service and Informational (Transcribe from line 8)	2,038,431		
26	Sales (Transcribe from line 9)	6,872,764		
27	Administrative and General (Enter Total of lines 10 and 17)	91,896,314		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	379,069,925		379,069,925
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	379,069,925		379,069,925
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	158,111,185		158,111,185
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	158,111,185		158,111,185
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Inventory	205,300		205,300
79	Deferred Debits	107,409		107,409
80	Other Revenue	74,516		74,516
81	Other Income	327		327
82	Miscellaneous Income Deductions	3,758,887		3,758,887
83	Misc. Deferred Debit Reconciling Items	2,094,463		2,094,463
84	Palo Verde Generating Station	213,548,419		213,548,419
85	Four Corners	17,244,314		17,244,314
86	Cholla-Pacificorp	8,981,271		8,981,271
87	Yucca	2,142,488		2,142,488
88	Morgan Pinnacle Peak	339,017		339,017
89	Cedar NU	88		88
90	PV-NG Yuma	326,911		326,911
91	Navajo STS 500 KV Line	1,379,169		1,379,169
92	Studies	27,874		27,874
93	Street Lights	640,672		640,672
94	Miscellaneous Billings	745,682		745,682
95	TOTAL Other Accounts	251,616,807		251,616,807
96	TOTAL SALARIES AND WAGES	788,797,917		788,797,917

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	2,448,050	4,099,061	5,748,367	6,703,684
3	Net Sales (Account 447)	(8,187,668)	(18,021,501)	(29,933,244)	(46,080,726)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(5,739,618)	(13,922,440)	(24,184,877)	(39,377,042)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	61,645	MW	1,803,363	67,964	MW	2,002,825
2	Reactive Supply and Voltage	61,645	MW		67,964	MW	
3	Regulation and Frequency Response	61,645	MW	6,939,384	64,173	MW	7,067,848
4	Energy Imbalance		MWh		-35,176	MWh	-364,042
5	Operating Reserve - Spinning	61,645	MW	15,919,257	64,173	MW	16,058,908
6	Operating Reserve - Supplement	61,645	MW	2,017,866	64,173	MW	2,039,384
7	Other						
8	Total (Lines 1 thru 7)	308,225		26,679,870	293,271		26,804,923

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 1 Column: e

Short-term demand excluded due to mismatch of demand measurement (Hourly, Daily, etc.). Short-term service accounts for $40,891 of sold revenue in column (g) for 2015.

Schedule Page: 398 Line No.: 2 Column: g

Service currently provided at $0 per MW.

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	5,079	2	800	4,308	151	339	281		
2	February	4,206	2	800	3,441	148	336	281		
3	March	4,907	30	1800	4,091	199	336	281		
4	Total for Quarter 1				11,840	498	1,011	843		
5	April	5,275	30	1700	4,438	220	336	281		
6	May	6,241	31	1800	5,384	234	342	281		
7	June	7,562	18	1700	6,741	108	432	281		
8	Total for Quarter 2				16,563	562	1,110	843		
9	July	7,057	2	1700	6,240	104	432	281		
10	August	7,932	15	1700	7,122	97	432	281		
11	September	6,786	8	1700	5,991	82	432	281		
12	Total for Quarter 3				19,353	283	1,296	843		
13	October	6,351	1	1700	5,571	67	432	281		
14	November	4,692	30	800	3,886	93	432	281		
15	December	5,248	17	800	4,432	103	432	281		
16	Total for Quarter 4				13,889	263	1,296	843		
17	Total Year to Date/Year				61,645	1,606	4,713	3,372		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 400 Line No.: 1 Column: b

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 1 Column: e

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 2 Column: b

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 2 Column: e

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 3 Column: b

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 3 Column: e

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 5 Column: b

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 5 Column: e

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 5 Column: f

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 7 Column: b

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 7 Column: f

Updated type of service per settlement agreement (docket ER15-710-002)

Schedule Page: 400 Line No.: 7 Column: g

Updated type of service per settlement agreement (docket ER15-710-002)

Schedule Page: 400 Line No.: 11 Column: b

Updated due to counterparty checkouts

Schedule Page: 400 Line No.: 11 Column: f

Updated due to counterparty checkouts

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	27,950,491
3	Steam	15,907,972			
4	Nuclear	9,461,777	23	Requirements Sales for Resale (See instruction 4, page 311.)	150,328
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,528,035
7	Other	2,072,529			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	27,442,278	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	63,255
10	Purchases	7,772,414	27	Total Energy Losses	1,386,069
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	35,078,178
12	Received	796,496			
13	Delivered	953,698			
14	Net Exchanges (Line 12 minus line 13)	-157,202			
15	Transmission For Other (Wheeling)				
16	Received	42,282,561			
17	Delivered	42,261,873			
18	Net Transmission for Other (Line 16 minus line 17)	20,688			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	35,078,178			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,374,709	244,041	4,391	2	8:00
30	February	2,078,108	337,864	3,510	2	8:00
31	March	2,461,937	461,179	4,209	30	18:00
32	April	2,380,665	357,128	4,572	30	17:00
33	May	2,775,225	545,258	5,556	31	18:00
34	June	3,566,763	555,642	6,940	18	17:00
35	July	3,845,211	577,311	6,414	2	17:00
36	August	4,019,849	460,006	7,320	15	17:00
37	September	3,420,766	569,880	6,136	8	17:00
38	October	2,941,367	617,264	5,726	1	17:00
39	November	2,547,279	616,102	3,965	30	8:00
40	December	2,666,299	404,703	4,516	17	8:00
41	TOTAL	35,078,178	5,746,378			

Schedule Page: 401 Line No.: 29 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 29 Column: d

Updated due to counterparty checkouts

Schedule Page: 401 Line No.: 30 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 30 Column: d

Updated due to counterparty checkouts

Schedule Page: 401 Line No.: 31 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 31 Column: d

Updated due to counterparty checkouts

Schedule Page: 401 Line No.: 32 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 32 Column: d

Updated due to counterparty checkouts

Schedule Page: 401 Line No.: 33 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 34 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 35 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 36 Column: b

Adjusted to better reflect monthly activity

Schedule Page: 401 Line No.: 37 Column: b

Adjusted to better reflect monthly activity

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Cholla 1* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Over 50% Outdoor	
3	Year Originally Constructed	1962	
4	Year Last Unit was Installed	1981	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	113.60	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	113	0
7	Plant Hours Connected to Load	7093	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	116	0
10	When Limited by Condenser Water	116	0
11	Average Number of Employees	45	0
12	Net Generation, Exclusive of Plant Use - KWh	627267666	0
13	Cost of Plant: Land and Land Rights	1415539	0
14	Structures and Improvements	20543084	0
15	Equipment Costs	142374201	0
16	Asset Retirement Costs	6435774	0
17	Total Cost	170768598	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1503.2447	0
19	Production Expenses: Oper, Supv, & Engr	1595890	0
20	Fuel	11941579	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	2581846	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	523399	0
26	Misc Steam (or Nuclear) Power Expenses	1030310	0
27	Rents	0	0
28	Allowances	484478	0
29	Maintenance Supervision and Engineering	1453486	0
30	Maintenance of Structures	1153391	0
31	Maintenance of Boiler (or reactor) Plant	3004907	0
32	Maintenance of Electric Plant	385188	0
33	Maintenance of Misc Steam (or Nuclear) Plant	1298492	0
34	Total Production Expenses	25452966	0
35	Expenses per Net KWh	0.0406	0.0000

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Gas	Total		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Bbls	MCF			
38	Quantity (Units) of Fuel Burned	366496	0	2038	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9175	0	862675	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	43.959	0.000	10.473	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	36.066	0.000	-150.442	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.965	0.000	-174.390	1.775	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	-1.870	0.019	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	10724.361	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: *Four Corners 1* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)				Over 50% Outdoor		
3	Year Originally Constructed				1963		
4	Year Last Unit was Installed				1970		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			25		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			901393		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			-241307		
27	Rents	0			105322		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			529		
31	Maintenance of Boiler (or reactor) Plant	0			34256		
32	Maintenance of Electric Plant	0			858		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			13292		
34	Total Production Expenses	0			814343		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Total			Coal	Gas	Total
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				Tons	MCF	
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.770	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.030	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10714.799	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Four Corners 5* (b)			Plant Name: *Ocotillo 1* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Over 50% Outdoor			Over 50% Outdoor
3	Year Originally Constructed			1969			1960
4	Year Last Unit was Installed			1970			1960
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			515.40			113.60
6	Net Peak Demand on Plant - MW (60 minutes)			768			102
7	Plant Hours Connected to Load			7414			1384
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			485			110
10	When Limited by Condenser Water			485			110
11	Average Number of Employees			27			11
12	Net Generation, Exclusive of Plant Use - KWh			3146105513			55383000
13	Cost of Plant: Land and Land Rights			34814			152872
14	Structures and Improvements			14283669			2358015
15	Equipment Costs			129048527			27049081
16	Asset Retirement Costs			9678744			0
17	Total Cost			153045754			29559968
18	Cost per KW of Installed Capacity (line 17/5) Including			296.9456			260.2110
19	Production Expenses: Oper, Supv, & Engr			2342088			0
20	Fuel			76278511			2155028
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			7718818			186612
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			761211			873557
26	Misc Steam (or Nuclear) Power Expenses			3988930			180614
27	Rents			431159			0
28	Allowances			2429933			42776
29	Maintenance Supervision and Engineering			1174728			0
30	Maintenance of Structures			1576445			201748
31	Maintenance of Boiler (or reactor) Plant			11481491			86382
32	Maintenance of Electric Plant			1947559			655989
33	Maintenance of Misc Steam (or Nuclear) Plant			5277108			158778
34	Total Production Expenses			115407981			4541484
35	Expenses per Net KWh			0.0367			0.0820
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas	Total	Gas	Total	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	MCF		MCF		
38	Quantity (Units) of Fuel Burned	1739325	142619	0	1259859	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8892	1032487	0	1001455	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	40.986	5.925	0.000	1.547	0.000	0.000
41	Average Cost of Fuel per Unit Burned	43.318	6.551	0.000	1.711	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.436	6.345	2.454	1.708	1.708	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.063	0.024	0.039	0.039	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	9878.185	0.000	22781.214	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Navajo* (b)			Plant Name: *Yucca 1* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam Units 1,2,3			Comb. Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Over 50% Outdoor			Over 50% Outdoor		
3	Year Originally Constructed	1974			1971		
4	Year Last Unit was Installed	1976			2008		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	337.34			23.60		
6	Net Peak Demand on Plant - MW (60 minutes)	320			18		
7	Plant Hours Connected to Load	23295			71		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	315			19		
10	When Limited by Condenser Water	315			0		
11	Average Number of Employees	0			3		
12	Net Generation, Exclusive of Plant Use - KWh	1385869001			616000		
13	Cost of Plant: Land and Land Rights	25111			33986		
14	Structures and Improvements	32849766			605677		
15	Equipment Costs	238125776			2795511		
16	Asset Retirement Costs	1865912			0		
17	Total Cost	272866565			3435174		
18	Cost per KW of Installed Capacity (line 17/5) Including	808.8770			145.5582		
19	Production Expenses: Oper, Supv, & Engr	3588046			0		
20	Fuel	32366092			39910		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1830776			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1118896			300342		
26	Misc Steam (or Nuclear) Power Expenses	4383842			0		
27	Rents	85176			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1439596			0		
30	Maintenance of Structures	255345			437		
31	Maintenance of Boiler (or reactor) Plant	7283106			0		
32	Maintenance of Electric Plant	2896741			121069		
33	Maintenance of Misc Steam (or Nuclear) Plant	755250			453		
34	Total Production Expenses	56002866			462211		
35	Expenses per Net KWh	0.0404			0.7503		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Total	Oil	Gas	Total
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Bbls		Bbls	MCF	
38	Quantity (Units) of Fuel Burned	618020	4594	0	0	11690	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	10754	136819	0	0	1046308	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	47.205	107.136	0.000	0.000	1.841	0.000
41	Average Cost of Fuel per Unit Burned	51.327	140.451	0.000	0.000	3.414	0.000
42	Average Cost of Fuel Burned per Million BTU	2.386	24.442	2.430	0.000	3.263	3.263
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.235	0.023	0.000	0.065	0.065
44	Average BTU per KWh Net Generation	0.000	0.000	9610.303	0.000	0.000	19855.519

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Yucca 5* (b)			Plant Name: *Yucca 6* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Comb. Turbine			Comb. Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Over 50% Outdoor			Over 50% Outdoor		
3	Year Originally Constructed	2007			2007		
4	Year Last Unit was Installed	2008			2008		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	60.50			60.50		
6	Net Peak Demand on Plant - MW (60 minutes)	48			48		
7	Plant Hours Connected to Load	1135			1160		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	48			48		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	2			0		
12	Net Generation, Exclusive of Plant Use - KWh	22689000			25547000		
13	Cost of Plant: Land and Land Rights	13711			0		
14	Structures and Improvements	1755189			1743296		
15	Equipment Costs	36301565			35956047		
16	Asset Retirement Costs	0			0		
17	Total Cost	38070465			37699343		
18	Cost per KW of Installed Capacity (line 17/5) Including	629.2639			623.1296		
19	Production Expenses: Oper, Supv, & Engr	157600			177452		
20	Fuel	1429794			1529174		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			687861		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	20724			23334		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	511666			397131		
33	Maintenance of Misc Steam (or Nuclear) Plant	271269			159343		
34	Total Production Expenses	2391053			2974295		
35	Expenses per Net KWh	0.1054			0.1164		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas	Total	Oil	Gas	Total
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Bbls	MCF		Bbls	MCF	
38	Quantity (Units) of Fuel Burned	0	277830	0	0	286116	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1063805	0	0	1039613	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	2.775	0.000	0.000	2.882	0.000
41	Average Cost of Fuel per Unit Burned	0.000	5.146	0.000	0.000	5.345	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	4.838	4.838	0.000	5.141	5.141
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.063	0.063	0.000	0.060	0.060
44	Average BTU per KWh Net Generation	0.000	0.000	13026.445	0.000	0.000	11643.246

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Saguaro 3* (b)			Plant Name: *Ocotillo 1* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Comb. Turbine			Comb. Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Over 50% Outdoor			Over 50% Outdoor		
3	Year Originally Constructed	2002			1972		
4	Year Last Unit was Installed	2002			1973		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	78.30			53.10		
6	Net Peak Demand on Plant - MW (60 minutes)	78			47		
7	Plant Hours Connected to Load	337			43		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	79			55		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			3		
12	Net Generation, Exclusive of Plant Use - KWh	16465000			628000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	510354			878490		
15	Equipment Costs	30015002			23098291		
16	Asset Retirement Costs	0			0		
17	Total Cost	30525356			23976781		
18	Cost per KW of Installed Capacity (line 17/5) Including	389.8513			451.5401		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	1162391			112877		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	8717			217983		
26	Misc Steam (or Nuclear) Power Expenses	0			62383		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			310174		
30	Maintenance of Structures	27758			40284		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	288683			250089		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			32161		
34	Total Production Expenses	1487549			1025951		
35	Expenses per Net KWh	0.0903			1.6337		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Total		Gas	Total	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	222311	0	0	18644	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1064621	0	0	1035523	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.820	0.000	0.000	3.265	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.229	0.000	0.000	6.054	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.911	4.911	0.000	5.847	5.847	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.071	0.071	0.000	0.180	0.180	0.000
44	Average BTU per KWh Net Generation	0.000	14374.552	0.000	0.000	30742.516	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Sundance* (b)			Plant Name: *West Phoenix 1* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Comb. Turbine			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Over 50% Outdoor			Over 50% Outdoor		
3	Year Originally Constructed	2002			1976		
4	Year Last Unit was Installed	2002			2003		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	605.00			132.00		
6	Net Peak Demand on Plant - MW (60 minutes)	443			160		
7	Plant Hours Connected to Load	1806			2331		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	420			88		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	14			3		
12	Net Generation, Exclusive of Plant Use - KWh	56518000			73861174		
13	Cost of Plant: Land and Land Rights	681252			4011		
14	Structures and Improvements	14017813			3040457		
15	Equipment Costs	278939233			46128524		
16	Asset Retirement Costs	0			0		
17	Total Cost	293638298			49172992		
18	Cost per KW of Installed Capacity (line 17/5) Including	485.3526			372.5227		
19	Production Expenses: Oper, Supv, & Engr	0			83557		
20	Fuel	2852855			5464311		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	705152			0		
26	Misc Steam (or Nuclear) Power Expenses	2957168			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	305050			17533		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	3019458			1547927		
33	Maintenance of Misc Steam (or Nuclear) Plant	23033			59497		
34	Total Production Expenses	9862716			7172825		
35	Expenses per Net KWh	0.1745			0.0971		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Total		Gas	Total	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	590601	0	0	929284	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1031551	0	0	1040602	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.605	0.000	0.000	3.171	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.830	0.000	0.000	5.880	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.683	4.683	0.000	5.651	5.651	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.050	0.050	0.000	0.074	0.074	0.000
44	Average BTU per KWh Net Generation	0.000	10779.486	0.000	0.000	13092.332	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *West Phoenix 5* (b)			Plant Name: *Redhawk 1* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Combined Cycle			Combined Cycle
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Over 50% Outdoor			Over 50% Outdoor
3	Year Originally Constructed			2003			2002
4	Year Last Unit was Installed			2003			2002
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			569.60			573.10
6	Net Peak Demand on Plant - MW (60 minutes)			481			552
7	Plant Hours Connected to Load			8622			19934
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			506			492
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			31			14
12	Net Generation, Exclusive of Plant Use - KWh			1447168000			2375275000
13	Cost of Plant: Land and Land Rights			28158			1128691
14	Structures and Improvements			14963054			12686806
15	Equipment Costs			287827833			268220371
16	Asset Retirement Costs			0			0
17	Total Cost			302819045			282035868
18	Cost per KW of Installed Capacity (line 17/5) Including			531.6346			492.1233
19	Production Expenses: Oper, Supv, & Engr			1637144			51678
20	Fuel			56701989			88792024
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			3178378			1165032
26	Misc Steam (or Nuclear) Power Expenses			3115645			3799503
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			349544			351698
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			4242485			3076494
33	Maintenance of Misc Steam (or Nuclear) Plant			859365			1295921
34	Total Production Expenses			70084550			98532350
35	Expenses per Net KWh			0.0484			0.0415
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Total		Gas	Total	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	14280130	0	0	15217044	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1596805	0	0	2225805	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.141	0.000	0.000	3.147	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.971	0.000	0.000	5.835	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.273	5.273	0.000	5.152	5.152	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.039	0.039	0.000	0.037	0.037	0.000
44	Average BTU per KWh Net Generation	0.000	7608.871	0.000	0.000	7237.714	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Palo Verde 3* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Under 50% Outdoor	
3	Year Originally Constructed	1988	
4	Year Last Unit was Installed	1988	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	410.82	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	404	0
7	Plant Hours Connected to Load	8044	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	382	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	228	0
12	Net Generation, Exclusive of Plant Use - KWh	3056368442	0
13	Cost of Plant: Land and Land Rights	1618647	0
14	Structures and Improvements	309942586	0
15	Equipment Costs	766663534	0
16	Asset Retirement Costs	-21917073	0
17	Total Cost	1056307694	0
18	Cost per KW of Installed Capacity (line 17/5) Including	2571.2178	0
19	Production Expenses: Oper, Supv, & Engr	8552193	0
20	Fuel	25085750	0
21	Coolants and Water (Nuclear Plants Only)	4361714	0
22	Steam Expenses	4225547	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2873492	0
26	Misc Steam (or Nuclear) Power Expenses	13479831	0
27	Rents	15069645	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	3203195	0
30	Maintenance of Structures	810253	0
31	Maintenance of Boiler (or reactor) Plant	6088532	0
32	Maintenance of Electric Plant	5925180	0
33	Maintenance of Misc Steam (or Nuclear) Plant	1247190	0
34	Total Production Expenses	90922522	0
35	Expenses per Net KWh	0.0297	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Kg Uranium					
38	Quantity (Units) of Fuel Burned	466	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	66702	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2805.980	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	53889.540	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.795	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.008	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10327.541	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Cholla 2* (d)	Plant Name: (e)	Plant Name: *Cholla 3* (f)	Line No.
Steam		Steam	1
Over 50% Outdoor		Over 50% Outdoor	2
1978		1980	3
1981		1981	4
288.90	0.00	312.30	5
249	0	265	6
5760	0	6732	7
0	0	0	8
260	0	271	9
260	0	271	10
33	0	55	11
1076540381	0	1299762253	12
0	0	3933199	13
0	0	57194907	14
0	0	398384415	15
0	0	15035298	16
0	0	474547819	17
0.0000	0	1519.5255	18
1011347	0	2193634	19
29001814	0	38581471	20
0	0	0	21
3071172	0	3886734	22
0	0	0	23
0	0	0	24
358412	0	421238	25
928696	0	1389896	26
0	0	0	27
831479	0	1003887	28
884762	0	1964621	29
465870	0	466769	30
1713050	0	4448066	31
163653	0	810049	32
1249220	0	2095321	33
39679475	0	57261686	34
0.0369	0.0000	0.0441	35

(d)			(e)			(f)			Line No.
Coal	Oil	Gas	Total			Coal	Oil	Gas	36
Tons	Bbls	MCF				Tons	Bbls	MCF	37
660170	2893	0	0	0	0	758849	3456	0	38
9181	126416	0	0	0	0	9164	126550	0	39
40.212	105.600	0.000	0.000	0.000	0.000	44.433	116.201	0.000	40
42.630	259.539	0.000	0.000	0.000	0.000	48.701	390.705	0.000	41
2.322	48.882	0.000	2.390	0.000	0.000	2.657	73.508	0.000	42
0.026	0.551	0.000	0.027	0.000	0.000	0.028	0.788	0.000	43
0.000	0.000	0.000	11273.994	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Four Corners 2* (d)			Plant Name: *Four Corners 3* (e)			Plant Name: *Four Corners 4* (f)			Line No.
Steam			Steam			Steam			1
Over 50% Outdoor			Over 50% Outdoor			Over 50% Outdoor			2
1963			1964			1969			3
1970			1970			1970			4
0.00			0.00			515.40			5
0			0			791			6
0			0			7577			7
0			0			0			8
0			0			485			9
0			0			485			10
1			0			29			11
0			0			3377218267			12
0			0			29232			13
0			0			15760125			14
0			0			103048327			15
0			0			9671566			16
0			0			128509250			17
0			0			249.3389			18
-6709			-4696			2439501			19
0			0			80951931			20
0			0			0			21
0			0			7883680			22
0			0			0			23
0			0			0			24
0			0			761210			25
9283			9286			4290133			26
105322			105322			431159			27
0			0			2608436			28
0			0			1174728			29
529			529			1254092			30
34039			33691			12684460			31
858			858			1546132			32
8775			8673			4530090			33
152097			153663			120555552			34
0.0000			0.0000			0.0357			35
Coal	Gas	Total	Coal	Gas	Total	Coal	Gas	Total	36
Tons	MCF		Tons	MCF		Tons	MCF		37
0	0	0	0	0	0	1880617	122141	0	38
0	0	0	0	0	0	8839	1085692	0	39
0.000	0.000	0.000	0.000	0.000	0.000	40.392	5.691	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	42.636	6.293	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	2.412	5.796	2.425	42
0.000	0.000	0.000	0.000	0.000	0.000	0.024	0.057	0.024	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	9883.454	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Ocotillo 2* (d)	Plant Name: *Saguaro 1* (e)	Plant Name: *Saguaro 2* (f)	Line No.
Steam	Steam	Steam	1
Over 50% Outdoor	Over 50% Outdoor	Over 50% Outdoor	2
1960	1954	1955	3
1960	1955	1955	4
113.60	0.00	0.00	5
110	0	0	6
1068	0	0	7
0	0	0	8
110	0	0	9
110	0	0	10
11	0	0	11
50139000	0	0	12
138712	0	52347	13
2446503	0	0	14
27274657	0	0	15
0	0	0	16
29859872	0	52347	17
262.8510	0	0	18
0	0	0	19
1945646	6075	6075	20
0	0	0	21
168942	0	0	22
0	0	0	23
0	0	0	24
866235	2277	2277	25
163513	172719	0	26
0	0	0	27
38725	0	0	28
0	1216	1216	29
106502	843	843	30
140617	280	0	31
455352	0	0	32
143744	13870	0	33
4029276	197280	10411	34
0.0804	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Total		Gas	Total		Gas	Total		36
MCF			MCF			MCF			37
556235	0	0	0	0	0	0	0	0	38
1492380	0	0	0	0	0	0	0	0	39
3.163	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.498	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
2.344	2.344	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.039	0.039	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	16556.254	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Yucca 2* (d)			Plant Name: *Yucca 3* (e)			Plant Name: *Yucca 4* (f)			Line No.
Comb. Turbine			Comb. Turbine			Comb. Turbine			1
Over 50% Outdoor			Over 50% Outdoor			Over 50% Outdoor			2
1971			1973			1974			3
2008			2008			2008			4
23.60			72.40			72.40			5
19			50			18			6
64			161			5			7
0			0			0			8
19			55			54			9
0			0			0			10
1			1			1			11
617000			3374000			45000			12
0			0			0			13
472555			972279			706722			14
2597402			15841137			7583390			15
0			0			0			16
3069957			16813416			8290112			17
130.0829			232.2295			114.5043			18
0			0			0			19
32908			525207			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			3372			26
0			0			0			27
0			0			0			28
0			0			0			29
438			2393			32			30
0			0			0			31
512212			218070			58498			32
578			4051			0			33
546136			749721			61902			34
0.8851			0.2222			1.3756			35
Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total	36
Bbls	MCF		Bbls	MCF		Bbls	MCF		37
0	11166	0	0	64476	0	180	0	0	38
0	1047167	0	0	1042869	0	137697	0	0	39
0.000	1.589	0.000	0.000	2.399	0.000	0.000	0.000	0.000	40
0.000	2.947	0.000	0.000	4.448	0.000	0.000	0.000	0.000	41
0.000	2.814	2.814	0.000	4.265	7.811	0.000	0.000	0.000	42
0.000	0.053	0.053	0.000	0.085	0.156	0.000	0.000	0.000	43
0.000	0.000	18951.378	0.000	0.000	19928.868	0.000	0.000	23133.169	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Douglas* (d)			Plant Name: *Saguaro 1* (e)			Plant Name: *Saguaro 2* (f)			Line No.
		Comb. Turbine			Comb. Turbine			Comb. Turbine	1
		Over 50% Outdoor			Over 50% Outdoor			Over 50% Outdoor	2
		1972			1972			1973	3
		1972			2002			2002	4
		26.10			53.10			53.10	5
		16			55			45	6
		48			36			34	7
		0			0			0	8
		16			55			55	9
		0			0			0	10
		0			0			0	11
		397000			847000			832000	12
		9557			0			0	13
		103952			1310745			1351929	14
		5268581			15745362			10448309	15
		0			0			0	16
		5382090			17056107			11800238	17
		206.2103			321.2073			222.2267	18
		2937			0			0	19
		131458			82100			92157	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			448			440	25
		2985			51577			51577	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		36327			1100			1180	30
		0			0			0	31
		229108			56052			108095	32
		29389			25354			149387	33
		432204			216631			402836	34
		1.0887			0.2558			0.4842	35
Oil	Total		Gas	Total		Gas	Total		36
Bbls			MCF			MCF			37
1158	0	0	22044	0	0	22969	0	0	38
136506	0	0	1065324	0	0	1066916	0	0	39
109.843	0.000	0.000	2.008	0.000	0.000	2.164	0.000	0.000	40
113.530	0.000	0.000	3.724	0.000	0.000	4.012	0.000	0.000	41
19.802	19.802	0.000	3.496	3.496	0.000	3.761	3.761	0.000	42
0.331	0.331	0.000	0.097	0.097	0.000	0.111	0.111	0.000	43
0.000	16721.881	0.000	0.000	27726.092	0.000	0.000	29454.327	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Ocotillo 2* (d)	Plant Name: *West Phoenix 1* (e)	Plant Name: *West Phoenix 2* (f)	Line No.
Comb. Turbine	Comb. Turbine	Comb. Turbine	1
Over 50% Outdoor	Over 50% Outdoor	Over 50% Outdoor	2
1973	1972	1973	3
1973	1973	1973	4
53.10	53.10	53.10	5
52	28	47	6
47	48	83	7
0	0	0	8
55	55	55	9
0	0	0	10
2	1	2	11
656000	618000	746000	12
0	6294	0	13
1074733	2105490	1822390	14
19744846	18012862	20057159	15
0	0	0	16
20819579	20124646	21879549	17
392.0825	378.9952	412.0442	18
0	50200	60597	19
110920	84422	118719	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
210747	37858	45699	25
56476	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
34931	424	7030	30
0	0	0	31
115744	204470	124515	32
0	31862	3655	33
528818	409236	360215	34
0.8061	0.6622	0.4829	35

(d)			(e)			(f)			Line No.
Gas			Gas	Total		Gas			36
MCF			MCF			MCF			37
20106	0	0	15924	0	0	20167	0	0	38
1038347	0	0	1041070	0	0	1039173	0	0	39
2.975	0.000	0.000	2.859	0.000	0.000	3.175	0.000	0.000	40
5.517	0.000	0.000	5.302	0.000	0.000	5.887	0.000	0.000	41
5.313	5.313	0.000	5.092	5.092	0.000	5.665	5.665	0.000	42
0.169	0.169	0.000	0.137	0.137	0.000	0.159	0.159	0.000	43
0.000	31824.695	0.000	0.000	26825.243	0.000	0.000	28092.493	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *West Phoenix 2* (d)			Plant Name: *West Phoenix 3* (e)			Plant Name: *West Phoenix 4* (f)			Line No.
Combined Cycle			Combined Cycle			Combined Cycle			1
Over 50% Outdoor			Over 50% Outdoor			Over 50% Outdoor			2
1976			1976			2001			3
2003			2003			2003			4
132.00			132.00			135.60			5
80			90			109			6
2459			1860			1312			7
0			0			0			8
88			88			117			9
0			0			0			10
2			3			8			11
80265144			101007262			109286000			12
3711			4619			36557			13
2421148			4339750			5561109			14
43074534			52290244			82219664			15
0			0			0			16
45499393			56634613			87817330			17
344.6924			429.0501			647.6204			18
90802			114267			483010			19
5705986			5841741			5236694			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			519405			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
12021			15914			23944			30
0			0			0			31
210727			776458			906172			32
148794			111538			73477			33
6168330			6859918			7242702			34
0.0768			0.0679			0.0663			35
Gas	Total		Gas	Total		Gas	Total		36
MCF			MCF			MCF			37
988740	0	0	960220	0	0	993478	0	0	38
1041101	0	0	1040402	0	0	1040983	0	0	39
3.112	0.000	0.000	3.281	0.000	0.000	2.843	0.000	0.000	40
5.771	0.000	0.000	6.084	0.000	0.000	5.271	0.000	0.000	41
5.543	5.543	0.000	5.848	5.848	0.000	5.064	5.064	0.000	42
0.071	0.071	0.000	0.058	0.058	0.000	0.048	0.048	0.000	43
0.000	12824.720	0.000	0.000	9890.526	0.000	0.000	9463.188	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Redhawk 2* (d)	Plant Name: *Palo Verde 1* (e)	Plant Name: *Palo Verde 2* (f)	Line No.
Combined Cycle	Nuclear	Nuclear	1
Over 50% Outdoor	Under 50% Outdoor	Under 50% Outdoor	2
2002	1986	1986	3
2002	1988	1988	4
567.20	410.82	410.82	5
549	391	402	6
19060	8760	7889	7
0	0	0	8
492	382	382	9
0	0	0	10
26	205	229	11
2149994000	3375856203	3029553576	12
1056089	1694862	1104281	13
10988053	312558246	194285654	14
242875792	814566341	543326229	15
0	-17074386	-14668759	16
254919934	1111745063	724047405	17
449.4357	2706.1610	1762.4444	18
46776	8724828	8549183	19
82791392	27017581	26478450	20
0	4360405	4360405	21
0	3415668	4323374	22
0	0	0	23
0	0	0	24
2341707	2919664	2627223	25
3439143	12996127	13433273	26
0	15065125	15065125	27
0	0	0	28
0	679798	2125945	29
311235	521845	839244	30
0	2169345	5913294	31
10804524	3262032	7155164	32
1079111	844538	1305401	33
100813888	81976956	92176081	34
0.0469	0.0243	0.0304	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Gas	Total		Nuclear			Nuclear			36
MCF			Kg Uranium			Kg Uranium			37
15164584	0	0	501	0	0	491	0	0	38
2101174	0	0	66702	0	0	66700	0	0	39
2.944	0.000	0.000	0.000	0.000	0.000	2871.754	0.000	0.000	40
5.460	0.000	0.000	53889.540	0.000	0.000	53889.540	0.000	0.000	41
5.197	5.197	0.000	0.779	0.000	0.000	0.853	0.000	0.000	42
0.039	0.039	0.000	0.008	0.000	0.000	0.009	0.000	0.000	43
0.000	7557.174	0.000	10270.772	0.000	0.000	10241.251	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 402.1 Line No.: -1 Column: c

Four Corners Units 1 - 3 began shutdown operations December 30, 2013

Schedule Page: 403.1 Line No.: -1 Column: d

Four Corners Units 1 - 3 began shutdown operations December 30, 2013

Schedule Page: 403.1 Line No.: -1 Column: e

Four Corners Units 1 - 3 began shutdown operations December 30, 2013

Schedule Page: 403.2 Line No.: -1 Column: e

Saguaro steam plants were retired effective June 30, 2013

Schedule Page: 403.2 Line No.: -1 Column: f

Saguaro steam plants were retired effective June 30, 2013

Schedule Page: 402.6 Line No.: 5 Column: b

Sundance: Generator Name Plate Rating is 605 MW at 15 degrees C and 0.85 Power Factor. Plant Output is limited by gas turbine.

Schedule Page: 403.7 Line No.: 1 Column: e

The Palo Verde Nuclear Units have pressurized water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of nuclear fuel is amortized to fuel expense (acct. 518) based on the fuel burns, or quantity of heat, produced in the generation of energy. Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from the reactors. Additional information on APS' nuclear fuel program and nuclear decommissioning is detailed in the Notes to Consolidated Financial Statements.

Schedule Page: 403.7 Line No.: 1 Column: f

The Palo Verde Nuclear Units have pressurized water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of nuclear fuel is amortized to fuel expense (acct. 518) based on the fuel burns, or quantity of heat, produced in the generation of energy. Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from the reactors. Additional information on APS' nuclear fuel program and nuclear decommissioning is detailed in the Notes to Consolidated Financial Statements.

Schedule Page: 402.8 Line No.: 1 Column: b

The Palo Verde Nuclear Units have pressurized water reactors. The nuclear fuel assemblies in the reactors contain enriched uranium. The cost of nuclear fuel is amortized to fuel expense (acct. 518) based on the fuel burns, or quantity of heat, produced in the generation of energy. Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from the reactors. Additional information on APS' nuclear fuel program and nuclear decommissioning is detailed in the Notes to Consolidated Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Solar Plants					
2	Flagstaff	1997	0.45		807	2,566,632
3	Star	1998	0.22		198	2,121,478
4	Tempe	1998	0.01		12	12,817
5	Glendale Airport	1999	0.07		127	114,593
6	Gilbert	2001	0.12		234	56,928
7	Scottsdale Covered Parking	1999	0.29		552	557,305
8	Municipal Rooftops	1999				51,361
9	Yuma	2002	0.17		268	550,117
10	Prescott Earu	2002	0.18		404	162,310
11	Prescott	2001	2.71		4,907	2,605,373
12	Red Rock	2005				
13	Phoenix	1998	3.05		100	29,052
14	Hyder Phase 1 & 2	2011	16.00		42,004	73,340,993
15	Hyder II	2013	14.00		43,826	51,811,899
16	Cotton Center	2011	17.00		42,798	80,506,726
17	Paloma	2011	17.00		39,257	66,071,021
18	US Airways Center	2011	0.18		349	1,350,091
19	Chase Field	2011	0.06		96	1,477,062
20	Chino Valley	2012	19.00		46,476	86,991,993
21	Foothills 1 & 2	2012	35.00		110,820	143,313,165
22	APS Solar for Schools	2012	13.20		24,166	59,332,100
23	DVN1	2013	0.02		43	
24	Palo Verde Emergengy OPS Center	2013	0.03		66	
25	Gila Bend Phase 1	2014	16.00		52,035	110,142,135
26	Gila Bend Phase 2	2014	16.00		52,767	
27	Carol Spring	2015				528,504
28	Desert Star	2015	10.00		14,817	32,597,473
29	Luke AFB	2015	10.00		18,441	32,297,721
30	Total Solar Operation/Maintenance		190.76		495,570	748,588,849
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
5,700,585						2
9,469,533						3
2,194,693						4
1,598,678						5
494,169						6
1,949,708						7
						8
3,316,196						9
880,587						10
959,811						11
						12
9,544						13
4,583,812						14
3,700,850						15
4,735,690						16
3,886,531						17
7,418,737						18
23,383,072						19
4,578,526						20
4,094,662						21
4,494,862						22
						23
						24
6,883,883						25
						26
						27
3,259,747						28
3,229,772						29
3,924,281	3,251,052					30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 410 Line No.: 1 Column: a

Solar is not required to be reported on these pages but we are choosing to report it here.

Schedule Page: 410 Line No.: 12 Column: a

Red Rock was decommissioned on 04/30/13.

Schedule Page: 410 Line No.: 30 Column: a

O&M Expenses for Solar Plants are not broken out by plant or between Operations and Maintenance.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	PALO VERDE	KYRENE	500.00	500.00	(3) STEEL (A)		74.80	1
2	PALO VERDE	WESTWING #2	500.00	500.00	(3) STEEL (A)		45.00	1
3	FOUR CORNERS	COLORADO RIVER	500.00	500.00	(3) STEEL	366.00		1
4	NAVAJO PLANT	WESTWING	500.00	500.00	(3) STEEL (A)		256.00	1
5	NAVAJO PLANT	MOENKOPI	500.00	500.00	(3) STEEL (A)		76.00	1
6	MOENKOPI	WESTWING	500.00	500.00	(3) STEEL (A)		180.00	1
7	CHOLLA	SAGUARO	500.00	500.00	(3) STEEL	206.00		1
8	PALO VERDE	WESTWING	500.00	500.00	(3) STEEL (A)		47.00	1
9	PALO VERDE	NORTH GILA	500.00	500.00	(3) STEEL (A)		120.00	1
10	WESTWING	MEAD	500.00	500.00	(3) STEEL (A)	242.70		1
11	MEAD	MARKET PLACE	500.00	500.00	(3) STEEL (A)	13.30		1
12	KYRENE/PALO VERDE	JOJOBA SUB	500.00	500.00	(3) STEEL	0.25		1
13	GILA RIVER	JOJOBA SWITCHYARD	500.00	500.00	(3) STEEL	18.50		2
14	PALO VERDE	RUDD	500.00	500.00	(3) STEEL (A)	35.68		1
15	PALO VERDE	HASSAYAMPA	500.00	500.00	(3) STEEL (A)		3.10	1
16	MORGAN	PINNACLE PEAK	500.00	500.00	(3) STEEL (A)	27.00	6.00	1
17	WESTWING	DUGAS LOOP	500.00	500.00	(3) STEEL			1
18	HASSAYAMPA	NORTH GILA	500.00	500.00	(3) STEEL (A)	111.50		1
19	FOUR CORNERS	PINNACLE PEAK	345.00	345.00	(3) STEEL (C)	566.00	12.00	2
20	YAVAPAI	TAP IN & OUT	230.00	230.00	(1) STEEL	1.30		2
21	WESTWING	EL SOL	230.00	345.00	(3) STEEL (D)		12.77	1
22	CHOLLA PLANT	FLAGSTAFF	230.00	230.00	(2) WOOD	88.14		1
23	LIBERTY	GILA BEND	230.00	230.00	(3) STEEL (D)		6.00	1
24	LIBERTY	GILA BEND	230.00	230.00	(1) WOOD	12.00		1
25	LIBERTY	GILA BEND	230.00	230.00	(2) WOOD	28.00		1
26	COCONINO	VERDE	230.00	230.00	(2) WOOD	32.68		1
27	VERDE	WILLOW LAKE	230.00	230.00	(2) WOOD	34.30		1
28	ROUND VALLEY	SELIGMAN	230.00	230.00	(2) WOOD	36.19		1
29	PINNACLE PEAK	OCOTILLO	230.00	230.00	(3) STEEL	51.20		2
30	EL SOL	AGUA FRIA	230.00	230.00	(3) STEEL	5.65		1
31	AGUA FRIA	GRAND TERMINAL	230.00	230.00	(1) STEEL	10.02		1
32	OCOTILLO PLANT	LINCOLN STREET	230.00	230.00	(3) STEEL	10.30	10.30	2
33	OCOTILLO PLANT	LINCOLN STREET	230.00	230.00	(4) U.G.	1.00		
34	OCOTILLO PLANT	SRP TAP KYRENE SUB	230.00	230.00	(1) STEEL	6.50		2
35	OCOTILLO PLANT	68TH ST & SALT RIVER	230.00	230.00	(3) STEEL		1.60	1
36					TOTAL	5,211.50	881.15	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	LINCOLN STREET	WEST PHOENIX PLANT	230.00	230.00	(3) STEEL	5.50		1
2	SANTA ROSA	SAGUARO PLANT	230.00	230.00	(2) WOOD	61.50		1
3	PINNACLE PEAK-OCOTILLO	CACTUS SUB TAP	230.00	230.00	(1) STEEL	3.20		2
4	PINNACLE PEAK/LONE	REACH SUB TAP	230.00	230.00	(1) STEEL	0.12		1
5	PINNACLE PEAK/LONE	REACH SUB	230.00	230.00	(4) U.G.	0.63		1
6	GILA BEND/LIBERTY	PANDA SWITCHYARD	230.00	230.00	(1) STEEL	0.25		1
7	SRP-PINNACLE PEAK	DEER VALLEY TAP	230.00	230.00	(1) STEEL	3.30		2
8	LINCOLN STREET	COUNTRY CLUB	230.00	230.00	(4) U.G.	3.50		1
9	SUNNYSLOPE	COUNTRY CLUB	230.00	230.00	(4) U.G.	7.50		1
10	GRAND TERMINAL	COUNTRY CLUB	230.00	230.00	(4) U.G.	2.50		1
11	SANTA ROSA	CASA GRANDE	230.00	230.00	(2) WOOD	14.95		1
12	CASA GRANDE	SAGUARO	230.00	230.00	(1) WOOD	6.74		1
13	CASA GRANDE	SAGUARO	230.00	230.00	(2) WOOD	38.97		1
14	WESTWING-EL SOL	SURPRISE	230.00	230.00	(1) STEEL	11.25		1
15	DEER VALLEY	ALEXANDER	230.00	230.00	(1) STEEL	7.60		1
16	PINNACLE PEAK	SUNNYSLOPE	230.00	230.00	(1) STEEL	16.70		1
17	OCOTILLO	SANTA ROSA	230.00	230.00	(2) WOOD	36.30		1
18	ROUND VALLEY/SELIGMAN	FORT ROCK	230.00	230.00	(2) WOOD	1.67		1
19	WHITE TANKS	WEST PHOENIX	230.00	230.00	(1) STEEL	12.00		2
20	EL SOL	WHITE TANKS	230.00	230.00	(3) STEEL	9.00		1
21	PINNACLE PEAK	LONE PEAK	230.00	230.00	(3) STEEL	11.90		1
22	MEADOWBROOK	SUNNYSLOPE	230.00	230.00	(4) U.G.	0.16		1
23	MEADOWBROOK	COUNTRY CLUB	230.00	230.00	(4) U.G.	0.17		1
24	RUDD	LIBERTY	230.00	230.00	(1) STEEL	20.48		1
25	PALO VERDE	NORTH GILA TAP	230.00	230.00	(1) STEEL	3.30		2
26	PALO VERDE	KYRENE TAP	230.00	230.00	(1) STEEL	3.30		2
27	MORGAN	RACEWAY TAP	230.00	230.00	(3) STEEL	0.75		1
28	TUBA CITY TAP	POWELL SUB	69.00	230.00	(2) WOOD	60.00		1
29	SAGUARO PLANT	SAN MANUEL	115.00	230.00	(2) WOOD	41.50		1
30	ORACLE	SAN MANUEL	115.00	115.00	(2) WOOD	21.06		1
31	ADAMS	MURAL	115.00	115.00	(2) WOOD	47.15		1
32	SANTA ROSA	ASARCO	115.00	115.00	(2) WOOD	11.00		1
33	ASARCO	VISTA	115.00	115.00	(2) WOOD	3.81		1
34	ASARCO	VISTA	115.00	115.00	(1) WOOD	3.02		1
35	WILLOW LAKE	BAGDAD	115.00	115.00	(2) WOOD	49.00		1
36					TOTAL	5,211.50	881.15	81

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	UNDERGROUND		69.00	69.00		29.35		
2	OVERHEAD		69.00	69.00		2,756.52	30.58	1
3	RELATED TRANSMISSION					1.64		
4	EHV STRUCTURES TEMP.							
5	LIMITED TERM LAND							
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,211.50	881.15	81

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1780 ACSR	4,014,277	19,901,127	23,915,404					1
1780 ACSR		5,971,160	5,971,160					2
2156 ACSR	2,321,510	39,917,113	42,238,623					3
2156 ACSR	743,746	8,831,923	9,575,669					4
2156 ACSR		1,208,159	1,208,159					5
2156 ACSR	55,612	5,807,204	5,862,816					6
2156 ACSR	1,350,823	60,391,579	61,742,402					7
1780 ACSR	8,522	5,151,452	5,159,974					8
2156 ACSR	494,861	4,727,505	5,222,366					9
1590 KCM	1,175,680	17,090,839	18,266,519					10
1590 KCM	50,610	626,769	677,379					11
954 ACSR								12
1780 ACSR								13
1780 ACSR	12,237,938	29,540,970	41,778,908					14
1780 ACSR	284,676	776,503	1,061,179					15
1780 ACSR	15,603,430	32,420,062	48,023,492					16
2156 ACSR		3,178,473	3,178,473					17
2156 ACSR	8,582,119	103,003,307	111,585,426					18
795 ACSR	4,744,391	30,649,195	35,393,586					19
954 ACSR		947,577	947,577					20
795 ACSR	424,643	3,424,030	3,848,673					21
795 ACSR	138,023	3,681,055	3,819,078					22
1272 ACSR	40,721	2,537,537	2,578,258					23
1272 ACSR	322,267	1,858,571	2,180,838					24
1272 ACSR	803,802	3,352,137	4,155,939					25
795 ACSR	35,944	3,135,075	3,171,019					26
795 ACSR	157,325	3,250,560	3,407,885					27
795 ACSR	8,969	2,097,188	2,106,157					28
795 AA	9,660,020	7,704,155	17,364,175					29
1431 AA	220,297	536,518	756,815					30
1361 ACAR	112,180	3,218,080	3,330,260					31
1431 AA	820,160	6,759,381	7,579,541					32
2000 KC		1,826,612	1,826,612					33
954 ACSR	1,931,778	4,017,851	5,949,629					34
954A/1113A		17,978	17,978					35
	135,385,358	1,140,613,003	1,275,998,361	25,966,635	15,008,345	7,550,709	48,525,689	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1113 AA	37,261	3,283,837	3,321,098					1
954A/1113A	383,722	3,077,401	3,461,123					2
954 AA	286,973	1,324,874	1,611,847					3
954 ACSR	171,181	203,127	374,308					4
1750 CU	142,671	855,388	998,059					5
1272 ACSR								6
954 AA	68,982	2,785,385	2,854,367					7
1750 CU	1,021,582	6,122,495	7,144,077					8
1750 CU	85,094	5,672,649	5,757,743					9
1750 CU	42,236	1,663,288	1,705,524					10
1272 ACSR	390,432	3,775,970	4,166,402					11
1272 ACSR	78,429	872,073	950,502					12
1272 ACSR	519,018	6,704,094	7,223,112					13
954 ACSR	381,847	1,203,882	1,585,729					14
954 AA	933,461	4,485,834	5,419,295					15
1431A/1361 ACSR	141,199	4,206,368	4,347,567					16
795R/1113A	352,384	6,951,684	7,304,068					17
795 AA		39,196	39,196					18
954 SSAC	7,389,772	16,026,636	23,416,408					19
954 ACSR	1,041,361	6,250,720	7,292,081					20
954 ACSR	3,600,766	7,821,426	11,422,192					21
1750 ACSR		618,139	618,139					22
1750 ACSR		857,317	857,317					23
1780 ACSR	8,241,786	13,492,925	21,734,711					24
954 AA		374,911	374,911					25
954 AA		383,526	383,526					26
2156 ACSS	6,687,184	13,894,312	20,581,496					27
954 ACSR		2,380,164	2,380,164					28
954 ACSR	46,640	1,951,111	1,997,751					29
556 ACSR	74,058	3,113,684	3,187,742					30
556 ACSR	435,033	2,115,819	2,550,852					31
795 ACSR	93,110	433,334	526,444					32
795 ACSR	18,029	392,494	410,523					33
795 ACSR	12,019	229,551	241,570					34
795 ACSR	365,101	3,027,431	3,392,532					35
	135,385,358	1,140,613,003	1,275,998,361	25,966,635	15,008,345	7,550,709	48,525,689	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
		38,244,872	38,244,872					1
	27,849,198	552,575,231	580,424,429					2
	21,621	5,328,484	5,350,105					3
		315,726	315,726					4
	8,128,884		8,128,884					5
				25,966,635	15,008,345	7,550,709	48,525,689	6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	135,385,358	1,140,613,003	1,275,998,361	25,966,635	15,008,345	7,550,709	48,525,689	36

Name of Respondent Arizona Public Service Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 422.2 Line No.: 3 Column: a

INCLUDES MINOR NAVAJO, FOUR CORNERS UNITS 1, 2, 3, PALO VERDE UNITS 1, 2, 3 REDHAWK COMBINED CYCLE AND WEST PHOENIX PLANT TO WEST PHOENIX COMBINED CYCLE RELATED TRANSMISSION

Schedule Page: 422.2 Line No.: 5 Column: a

INCLUDES LAND AND LAND RIGHTS FOR PALO VERDE TO SUN VALLEY, SUNDANCE TO PINAL CENTRAL, AND GILA RIVER TO JOJOBA

Schedule Page: 422.2 Line No.: 6 Column: a

STATEMENT OF CO-OWNERSHIP AS DESCRIBED IN INSTRUCTION #8, PAGE 423 AND AS NOTED ON PAGE 422 NONE OF THE CO-OWNERS IS AN ASSOCIATED COMPANY.

(A) CO-OWNERSHIP ON:

LINE # 4 - NAVAJO PLANT TO WESTWING
LINE # 5 - NAVAJO PLANT TO MOENKOPI
LINE # 6 - MOENKOPI TO WESTWING
LINE # 8 - PALO VERDE TO WESTWING
LINE # 9 - PALO VERDE TO NORTH GILA
LINE #10 - WESTWING TO MEAD
LINE #11 - MEAD TO MARKET PLACE
LINE # 1 - PALO VERDE TO KYRENE
LINE # 2 - PALO VERDE TO WESTWING #2
LINE #14 - PALO VERDE TO RUDD
LINE #15 - PALO VERDE TO HASSAYAMPA
LINE #16 - MORGAN TO PINNACLE PEAK
LINE #18 - HASSAYAMPA TO NORTH GILA

(1) CO-OWNERS OF LINES 4 & 6 ARE SALT RIVER PROJECT, TUCSON ELECTRIC POWER, AND U.S. DEPARTMENT OF ENERGY

(2) CO-OWNERS OF LINE 5 ARE SALT RIVER PROJECT, TUCSON ELECTRIC POWER, NEVADA POWER COMPANY, LOS ANGELES DEPARTMENT OF WATER AND POWER, AND U.S. DEPARTMENT OF ENERGY

(3) CO-OWNERS OF LINE 8 ARE SALT RIVER PROJECT, EL PASO ELECTRIC COMPANY, AND PUBLIC SERVICE OF NEW MEXICO

(4) CO-OWNERS OF LINE 9 ARE THE IMPERIAL IRRIGATION DISTRICT AND SAN DIEGO GAS AND ELECTRIC

(5) CO-OWNERS OF LINE 10 ARE M-S-R PUBLIC POWER AGENCY, SALT RIVER PROJECT, CITY OF VERNON, SOUTHERN CALIFORNIA PUBLIC AUTHORITY, AND U.S. DEPARTMENT OF ENERGY

(6) CO-OWNERS OF LINE 11 ARE M-S-R PUBLIC POWER AGENCY, SALT RIVER PROJECT, CITY OF VERNON, SOUTHERN CALIFORNIA PUBLIC AUTHORITY, AND U.S. DEPARTMENT OF ENERGY

(7) CO-OWNERS OF LINE 1 ARE SALT RIVER PROJECT, EL PASO ELECTRIC COMPANY, AND PUBLIC SERVICE OF NEW MEXICO

(8) CO-OWNERS OF LINE 2 ARE EL PASO ELECTRIC COMPANY, PUBLIC SERVICE OF NEW MEXICO, AND SALT RIVER PROJECT

(9) CO-OWNERS OF LINE 14 ARE SALT RIVER PROJECT AND ARIZONA PUBLIC SERVICE COMPANY

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) __ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

(10) CO-OWNERS OF LINE 15 ARE SALT RIVER PROJECT, EL PASO ELECTRIC COMPANY, AND PUBLIC SERVICE OF NEW MEXICO

(11) CO-OWNERS OF LINE 16 ARE SALT RIVER PROJECT AND ARIZONA PUBLIC SERVICE COMPANY

(12) CO-OWNERS OF LINE 18 ARE ARIZONA PUBLIC SERVICE COMPANY AND THE IMPERIAL IRRIGATION DISTRICT

(13) EXPENSES TO OPERATE THESE LINES ARE ALLOCATED TO PARTICIPANTS BASED ON OWNERSHIP AS SET FORTH IN OPERATION AND MAINTENANCE AGREEMENTS

(14) ARIZONA PUBLIC SERVICE COMPANY'S SHARE OF THE EXPENSES TO OPERATE THESE LINES ARE RECORDED IN TRANSMISSION EXPENSE ACCOUNTS 560, 561, 563, 566, 567, 571, AND 573

(C) A.P.S. DOUBLE CIRCUIT TOWERS WITH ANOTHER UTILITY ON ONE SIDE

(D) EXPENSES FOR THE OPERATION, MAINTENANCE AND RENTS ARE NOT SEGREGATED IN THE COMPANY'S BOOKS FOR EACH TRANSMISSION LINE

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	HASSAYAMPA	NORTH GILA	111.50	STEEL	4.00	1	1
2	TRILBY WASH	PALM VALLEY	15.90	STEEL/HYBRID	8.00	1	2
3	TRILBY WASH	PALM VALLEY	9.40	STEEL	8.00	1	2
4	MCMICKEN/TRILBY WASH	FESTIVAL RANCH	0.31	STEEL			
5	CHOLLA	WINSLOW	0.02	WOOD		1	1
6	ESTRELLITA	WILLIS	8.80	STEEL		1	2
7	BUTTE	RIO SALADO	0.87	STEEL		1	1
8	OCOTILLO	RIO SALADO	0.35	STEEL		1	1
9	HARQUAHALA	TONOPAH	0.24	STEEL		1	1
10	WADELL/DYSART	WADDELL/HEARN	3.26	STEEL		1	1
11	COTTON CENTER	GILLESPIE	5.00	STEEL	14.20	1	1
12	FESTIVAL/MCMICKEN	TRILBY WASH	1.75	STEEL		2	2
13	EL SOL	MERIDIAN	-0.01	STEEL		1	1
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		157.39		34.20	13	16

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
(2) 2156	ACSR	84/19	500	8,582,119	55,984,299	47,019,008		111,585,426	1
2156	KCMIL	84/19	230		11,702,034	5,015,157		16,717,191	2
795	ACSS	45/7	69		6,918,184	2,964,936		9,883,120	3
336.4	ACSR	26/7	69		468,034	200,586		668,620	4
795	ACSR	45/7	69		190,512	81,648		272,160	5
795	ACSS	45/7	69		3,225,528	1,382,369		4,607,897	6
795	ACSS	45/7	69		769,536	335,479		1,105,015	7
795	ACSS	45/7	69		319,769	137,044		456,813	8
795	ACSS	45/7	69		206,874	88,660		295,534	9
795	ACSS	45/7	69		130,521	55,937		186,458	10
795	ACSS	45/7	69	113,485	1,597,938	580,701		2,292,124	11
795	ACSS	45/7	69		661,205	283,374		944,579	12
795	ACSS	45/7	69		339,516	23,438		362,954	13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				8,695,604	82,513,950	58,168,337		149,377,891	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ACOMA-SCOTTSDALE	D	69.00	12.00	
2	ADAMS-BENSON	T	115.00		
3	ADOBE-PHOENIX	D	69.00	12.00	
4	AGUA FRIA SWYD - PEORIA	T	230.00	69.00	12.40
5	AGUILA-AGUILA	D	69.00	12.00	
6	AJO-AJO	D	69.00	21.00	
7	ALEXANDER-PHOENIX	T	69.00		
8	ALTADENA-SCOTTSDALE	D	69.00	12.00	
9	ANTELOPE-PRESCOTT	D	69.00	12.00	
10	AQUEDUCT - PHOENIX	D	69.00	4.16	
11	ARABY-YUMA	D	69.00	12.00	
12	ARICA-ELOY	D	69.00	12.00	
13	ARLINGTON-MARICOPA COUNTY	D	69.00	12.00	
14	ARROWHEAD-GLENDALE	D	69.00	12.00	
15	ARROYO-PHOENIX	D	69.00	12.00	
16	ASARCO PIT-CASA GRANDE	D	69.00	12.00	
17	ASHFORK-ASHFORK	D	69.00	12.00	
18	AZTEC - DATELAND	D	69.00	12.00	
19	BACON-N.W. OF SNOWFLAKE	D	69.00	12.00	
20	BADGER SUB - TONOPAH	D	69.00	12.00	
21	BAGDAD NEW TOWN - BAGDAD	T	115.00	12.00	
22	BAGDAD-115KV CAP.-BAGDAD	T	115.00		
23	BAJA-SAN LUIS	D	69.00	12.00	
24	BALD MOUNTAIN-PRESCOTT VALLEY	D	69.00	12.00	
25	BASELINE-BUCKEYE	D	69.00	12.00	
26	BEARDSLEY-SURPRISE	D	69.00	12.00	
27	BELL-PEORIA	D	69.00	12.00	
28	BISCUIT FLATS-PHOENIX	D	69.00		
29	BLACK MESA #2-GRAY MOUNTAIN	D	69.00		
30	BLACK PEAK(BOUSE APA) - PARKER	T	161.00	69.00	12.00
31	BLACK PEAK(BOUSE APA) - PARKER	D	69.00	12.00	
32	BLUE RIDGE-BLUE RIDGE	D	69.00	21.60	
33	BLUE WATER-N. OF PARKER	D	34.50	12.00	
34	BONNYBROOK-FLORENCE	D	115.00	12.00	
35	BOOTHILL-E. OF TOMBSTONE	D	115.00	21.00	
36	BOULEVARD-SCOTTSDALE	D	69.00	12.00	
37	BUCKEYE-BUCKEYE	T	230.00	69.00	12.00
38	BUCKEYE-BUCKEYE	D	69.00	12.00	
39	BUFFALO-PHOENIX	D	69.00	12.00	
40	BUNYAN-NW. OF GILA BEND	D	69.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BUTTE-TEMPE	D	69.00	12.00	
2	CACTUS-SCOTTSDALE	T	230.00	69.00	12.00
3	CACTUS-SCOTTSDALE	D	69.00	12.00	
4	CALDERWOOD-PEORIA	D	69.00	12.00	
5	CAMELBACK-SCOTTSDALE	D	69.00	12.00	
6	CAMERON-CAMERON	D	69.00	12.00	
7	CANAL-PHOENIX	D	69.00	12.00	
8	CAPITAL BUTTE-SEDONA	D	69.00	12.00	
9	CASA GRANDE-CASA GRANDE	T	230.00	69.00	12.00
10	CASA GRANDE-CASA GRANDE	D	230.00	12.00	
11	CASA GRANDE-CASA GRANDE	D	69.00	12.00	
12	CAVE CREEK-CAVE CREEK	D	69.00	12.00	
13	CEDAR MOUNTAIN-WILLIAMS	T	525.00		
14	CENTURY-SCOTTSDALE	D	69.00	12.00	
15	CHANDLER-CHANDLER	D	69.00	12.00	
16	CHAPARRAL-SCOTTSDALE	D	69.00	12.00	
17	CHERYL-PHOENIX	D	69.00	12.00	
18	CHILDS-CAMP VERDE	D	69.00		
19	CHINO VALLEY-CHINO VALLEY	D	69.00	12.00	
20	CHOLLA-JOSEPH CITY	A,T	525.00	345.00	34.50
21	CHOLLA-JOSEPH CITY	A,T	525.00		
22	CHOLLA-JOSEPH CITY	A,T	345.00	230.00	12.00
23	CHOLLA-JOSEPH CITY	A,T	345.00	69.00	
24	CHOLLA-JOSEPH CITY	A,T	230.00	69.00	4.16
25	CIELO GRANDE-PHOENIX	D	69.00	12.00	
26	CLINIC - SCOTTSDALE	D	69.00	12.00	
27	COCONINO-FLAGSTAFF	T	230.00	69.00	12.00
28	COCONINO-FLAGSTAFF	D	69.00	12.00	
29	COCOPAH-W. OF YUMA	D	69.00	12.00	
30	COLDWATER-GOODYEAR	D	69.00	12.00	
31	COLORADO-N. OF PARKER	D	69.00	12.00	
32	COLTER-AVONDALE	D	69.00	12.00	
33	CONLEY-SNOWFLAKE	T	69.00		
34	COOLIDGE-N. OF COOLIDGE	D	12.40		
35	COPPER CANYON-N. OF CAMP VERDE	D	69.00	12.00	
36	CORDES-CORDES JUNCTION	D	69.00	12.00	
37	CORNVILLE-CORNVILLE	D	69.00	12.00	
38	COTTON CENTER-N. OF GILA BEND	D	69.00	12.00	
39	COTTONWOOD-COTTONWOOD	D	69.00	12.00	
40	COTTONWOOD-COTTONWOOD	D			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	COUNTRY CLUB-PHOENIX	D	69.00	12.00	
2	COUNTRY CLUB-PHOENIX	T	230.00	69.00	12.00
3	COUNTY LINE - TONOPAH	D	69.00	12.00	
4	CROSSROADS-N. OF PARKER	D	34.50	12.00	
5	DALE-SCOTTSDALE	D	69.00	12.00	
6	DALE-SCOTTSDALE	D	69.00		
7	DAVENPORT- E. OF WILLIAMS	D	69.00	12.00	
8	DEADMAN WASH-PHOENIX	D	69.00	12.00	
9	DEADMAN WASH-PHOENIX	D	69.00		
10	DEER VALLEY-PHOENIX	T	230.00	69.00	12.00
11	DEER VALLEY-PHOENIX	D	69.00	12.00	
12	DEL RIO-PEORIA	D	69.00	12.00	
13	DELANO-PRESCOTT	D	69.00	12.00	
14	DESERT RIDGE-SCOTTSDALE	D	69.00	12.00	
15	DESERT SANDS - YUMA	T	69.00		
16	DESERT SKY-BUCKEYE	D	69.00	12.00	
17	DESERT SPRINGS-PHOENIX	D	69.00	12.00	
18	DEWEY-N. OF DEWEY	D	69.00	12.00	
19	DIXILETA-N. OF SCOTTSDALE	D	69.00	12.00	
20	DON LUIS-BISBEE	D	69.00	12.00	
21	DOUBLETREE-PHOENIX	D	69.00	12.00	
22	DOVE VALLEY-PHOENIX	D	69.00	12.00	
23	DOWNING-SCOTTSDALE	D	69.00	12.00	
24	DRAKE-PAULDEN	D	69.00		
25	DRY LAKE - HOLBROOK	D	69.00	7.20	
26	DUGAS-MAYER	T	525.00	69.00	34.50
27	DUGAS-MAYER	T			
28	DURANGO-PHOENIX	D	69.00	12.00	
29	DYSART-SURPRISE	D	69.00	12.00	
30	EAGLE EYE-W. OF AGUILA	T	230.00	69.00	12.00
31	EAST END-SCOTTSDALE	D	69.00	12.00	
32	EASTERN OFFICE-PHOENIX	D	69.00	12.00	
33	EASTGATE-CASA GRANDE	D	69.00	12.00	
34	EGG RANCH - TONOPAH	D	69.00	12.00	
35	EHRENBERG-EHRENBERG	D	34.50	12.00	
36	EL SOL-YOUNGTOWN	T	230.00	69.00	12.00
37	EL SOL-YOUNGTOWN	D	69.00	12.00	
38	ELDEN-FLAGSTAFF	D	69.00	12.00	
39	ENCANTO-PHOENIX	D	69.00	12.00	
40	ESTRELLITA-GOODYEAR	D	69.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EVANS CHURCHILL-PHOENIX	D	69.00	12.00	
2	FAIRVIEW-N. OF DOUGLAS	D	69.00	12.00	
3	FARMER - SURPRISE	T	69.00		
4	FESTIVAL RANCH-BUCKEYE	D	69.00	12.00	
5	FILLMORE-PHOENIX	D	69.00	12.00	
6	FISH SAWMILL-N. OF FLAGSTAFF	D	69.00	12.00	
7	FLORES-CONGRESS	D	69.00	12.00	
8	FLYING E-WICKENBURG	D	69.00	12.00	
9	FOOTHILLS-YUMA	D	69.00	12.00	
10	FORTIETH PLACE-PHOENIX	D	69.00	12.00	
11	FOUR CORNERS-FRUITLAND,NM	A,T	525.00	345.00	14.00
12	FOUR CORNERS-FRUITLAND,NM	A,T	345.00	230.00	14.40
13	FOUR CORNERS-FRUITLAND,NM	A,T	230.00	69.00	4.16
14	GARFIELD-PHOENIX	D	69.00	12.00	
15	GARLAND PRAIRIE-E. OF WILLIAMS	D	69.00	12.00	
16	GATEWAY - PHOENIX	D	69.00	12.00	
17	GAVILAN PEAK-PHOENIX	T	230.00	69.00	12.00
18	GAVILAN PEAK-PHOENIX	D	69.00	12.00	
19	GILA BEND-GILA BEND	T	230.00	69.00	12.00
20	GILA BEND-GILA BEND	D	69.00	12.00	
21	GILBERT-GILBERT	D	69.00	12.00	
22	GILLESPIE#1 - BUCKEYE	D	69.00	12.00	
23	GLENDALE-GLENDALE	D	230.00	12.00	
24	GRAND CANYON-GRAND CANYON	D	69.00	12.00	
25	GRANITE CREEK - CHINO VALLEY	T	69.00		
26	GRANITE REEF - SCOTTSDALE	D	69.00	12.00	
27	GRAY MOUNTAIN - CAMERON	D	69.00	21.60	
28	GREENBRIER-GLENDALE	D	69.00	12.00	
29	GREENWAY-GLENDALE	D	69.00	12.00	
30	GREY BEARS-CHINO VALLEY	D	69.00	12.00	
31	GRISWOLD-PHOENIX	D	69.00	12.00	
32	HAMBLIN - CAMERON	D	69.00	12.00	
33	HANKS-N. OF FLAGSTAFF	D	69.00	12.00	
34	HAPPY VALLEY TEMP-PEORIA	D	69.00	12.00	
35	HARBOR-PHOENIX	D	69.00	12.00	
36	HARQUAHALA-TONOPAH	D	69.00	12.00	
37	HASHKNIFE-HEBER	D	69.00		
38	HATFIELD-PEORIA	D	69.00	12.00	
39	HAVASU- PARKER	D	69.00	12.00	
40	HAYDEN-HAYDEN	D	21.00	7.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HAYES GULCH-GLOBE	D	69.00	21.00	
2	HEARN-SURPRISE	D	69.00	12.00	
3	HEDGEPETH HILLS-PHOENIX	D	69.00	12.00	
4	HOHOKAM-TEMPE	D	69.00	12.00	
5	HONEYWELL-PHOENIX	D	69.00	12.00	
6	HOODOO WASH - DATELAND	T	525.00		
7	HORN-HORN	D	69.00	12.00	
8	HOWARD-MESA-WILLIAMS	D	69.00	12.00	
9	HUMBUG-PEORIA	D	69.00	12.00	
10	HYDER - DATELAND	D	69.00	12.00	
11	INDIAN BEND-PHOENIX	D	69.00	12.00	
12	INDIANOLA-PHOENIX	D	69.00	12.00	
13	IVALON-YUMA	D	69.00	12.00	
14	JACKSON STREET-PHOENIX	D	69.00	12.00	
15	JAVELINA-SURPRISE	D	69.00	12.00	
16	JOMAX-SCOTTSDALE	D	69.00	12.00	
17	KACHINA-KACHINA VILLAGE	D	69.00	12.00	
18	KAIBAB - WILLIAMS	D	69.00	12.00	
19	KEAMS CANYON-W. OF KEAMS CANYON	D	69.00	21.00	
20	KEARNY-KEARNY	D	21.00		
21	KIRKLAND JUNCTION-SE. OF KIRKLAND	D	69.00	12.00	
22	LAGUNA - SOMERTON	D	69.00	12.00	
23	LE BARRON HILL-FLAGSTAFF	D	69.00	7.20	
24	LEROUX-N. OF HOLBROOK	D	69.00	12.00	
25	LEUPP JUNCTION - W. OF WINSLOW	D	69.00	21.00	
26	LIBERTY IRON-PHOENIX	D	69.00		
27	LINCOLN STREET (230kV)-PHOENIX	T	230.00	69.00	12.00
28	LINCOLN STREET NORTH-PHOENIX	D	69.00	12.00	
29	LINCOLN STREET WEST-PHOENIX	D	69.00	12.00	
30	LITCHFIELD-LITCHFIELD PARK	D	69.00	12.00	
31	LOMA VISTA-PHOENIX	D	69.00	12.00	
32	LONE PEAK-PHOENIX	T	230.00	69.00	12.00
33	LONE PEAK-PHOENIX	D	69.00	12.00	
34	LONESOME VALLY-PRESCOTT	D	69.00	12.00	
35	LOOKOUT-PHOENIX	D	69.00	12.00	
36	LUKE FIELD NORTH-LUKE AFB	D	69.00	12.00	
37	MAGNOLIA - STANTON	D	69.00	7.20	
38	MARINE AIR BASE-YUMA	D	69.00	12.00	
39	MARINETTE-SUN CITY	D	69.00	12.00	
40	MARTINEZ WASH-WICKENBURG	D	69.00	7.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MAZATAL-RYE	D	69.00	21.00	
2	MCGUIREVILLE - RIM ROCK	D	69.00	12.00	
3	MCCORMICK-SCOTTSDALE	D	69.00	12.00	
4	MCDOWELL-PHOENIX	D	69.00	12.00	
5	MCMICKEN-SURPRISE	D	69.00	12.00	
6	MEADOWBROOK-PHOENIX	T	230.00	69.00	12.00
7	MEADOWBROOK-PHOENIX	D	69.00	12.00	
8	MERIDIAN-GLENDALE	D	69.00		
9	MERRILL-FLORENCE	D	69.00	12.00	
10	METRO-PHOENIX	D	69.00	12.00	
11	MILLER WASH-VALLE	D	69.00	7.20	
12	MILLIGAN-ELOY	T	230.00	69.00	12.00
13	MILLIGAN TEMP-ELOY	D	69.00	12.00	
14	MINGUS-JEROME	D	69.00	7.20	
15	MITTRY	D	69.00	12.00	
16	MOENKOPI-CAMERON	T	525.00		
17	MOENKOPI-CAMERON	T	525.00		
18	MONTE CRISTO-PHOENIX	D	69.00	12.00	
19	MOON VALLEY-PHOENIX	D	69.00	12.00	
20	MORGAN-PEORIA	T	525.00	230.00	34.50
21	MORRISTOWN-MORRISTOWN	D	69.00	12.00	
22	MOUNTAIN VIEW-SUN CITY	D	69.00	12.00	
23	MT. FLOYD - SELIGMAN	D	4.16	12.00	
24	MT. FLOYD - SELIGMAN	T	230.00	12.00	
25	MUMMY MOUNTAIN-PARADISE VALLEY	D	69.00	12.00	
26	MUNDS PARK-S. OF FLAGSTAFF	D	69.00	21.00	
27	MURAL - BISBEE	D	69.00	12.00	
28	MURAL - BISBEE	T	115.00	69.00	12.00
29	NADASY-N. OF WILLIAMS	D	69.00	7.20	
30	NAVAJO-PAGE	A,T	525.00		
31	NAVAJO-PAGE	A,T	525.00		
32	NAVAJO ARMY DEPOT-FLAGSTAFF	D	69.00	12.00	
33	NEW RIVER-NEW RIVER	D	69.00	12.00	
34	NEWMAN PARK-S. OF FLAGSTAFF	D	69.00	7.20	
35	NORTH GILA-YUMA	T	525.00	230.00	34.50
36	NORTH GILA-YUMA	T	525.00	69.00	34.50
37	NORTH VALLEY-PHOENIX	D	69.00	12.00	
38	OAK CREAK-OAK CREEK	D	69.00	12.00	
39	OBERLIN TEMP - SURPRISE	D	69.00	12.00	
40	OCOTILLO-TEMPE	A,T	230.00	69.00	12.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	OCOTILLO-TEMPE	A,T			
2	OCOTILLO-TEMPE	A,T	69.00		
3	OLD HOME MANOR-CHINO VALLEY	D	69.00		
4	ORANGEWOOD-PHOENIX	D	69.00	12.00	
5	ORMES - MAYER	D	69.00	4.16	
6	OSBORNE TANK - FLAGSTAFF	D	69.00	12.00	
7	PADRE - FLAGSTAFF	D	69.00	12.00	
8	PALM VALLEY-GOODYEAR	T	230.00	69.00	12.00
9	PALM VALLEY-GOODYEAR	D	69.00	12.00	
10	PALOMA-W. OF GILA BEND	D	69.00	12.00	
11	PALOMINAS -HEREFORD	D	69.00	12.00	
12	PANDA - GILA BEND	A,T	230.00		
13	PAPAGO BUTTE-SCOTTSDALE	D	69.00	12.00	
14	PARADISE-PHOENIX	D	69.00	12.00	
15	PARKS-PARKS	D	69.00	12.00	
16	PATTERSON-OUT OF BUCKEYE	D	69.00	12.00	
17	PATTON-OUT OF MORRISTON	D	69.00	12.00	
18	PAULDEN-PAULDEN	D	69.00	12.00	
19	PEBBLECREEK-GOODYEAR	D	69.00	12.00	
20	PEORIA-PEORIA	D	69.00	12.00	
21	PERRYVILLE - PERRYVILLE	D	69.00	12.00	
22	PICKET-SUPERIOR	D	115.00	12.00	
23	PIMA-GOODYEAR	D	69.00	12.00	
24	PINAL-GLOBE	T	115.00	69.00	21.00
25	PINAL-GLOBE	D	69.00	21.00	
26	PINE SPRINGS-W. OF WILLIAMS	D	69.00	7.20	
27	PINNACLE PEAK-PHOENIX	T	525.00	230.00	34.50
28	PINNACLE PEAK-PHOENIX	T	345.00	230.00	14.40
29	PINNACLE PEAK-PHOENIX	T	230.00	69.00	12.40
30	PIONEER-PHOENIX	D	69.00	12.00	
31	PLANET-NE. OF PARKER	D	69.00	12.00	
32	PLEASANT-GLENDALE	D	69.00	12.00	
33	POLAND JUNCTION NW. OF MAYER	D	69.00	12.00	
34	POLK-PHOENIX	D	69.00	12.00	
35	POLK - PHOENIX	D	69.00	12.00	
36	POLLOCK -CHINO VALLEY	D	69.00	12.00	
37	POPLAR WASH-PEEPLES VALLEY	D	69.00	7.20	
38	PREACHER CANYON - STAR VALLEY	T	345.00	69.00	12.00
39	PREACHER CANYON - STAR VALLEY	D	69.00	21.60	
40	PRESCOTT CHINO WELLS-CHINO VALEY	D	69.00	4.16	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PRESCOTT CHINO WELLS - CHINO VALLEY	D	69.00	12.00	
2	PRESCOTT CITY-PRESCOTT	D	69.00	12.00	
3	PYRAMID PEAK-GLENDALE	D	69.00	12.00	
4	QUAIL SPRINGS-SE. OF COTTONWOOD	D	69.00	12.00	
5	QUARTZSITE-QUARTZSITE	D	69.00	12.00	
6	QUECHAN-YUMA	D	69.00	12.00	
7	RACEWAY-PEORIA	T	230.00	69.00	12.40
8	RAINBOW VALLEY-SE. OF BUCKEYE	D	69.00	12.00	
9	RAINTREE-SCOTTSDALE	D	69.00	12.00	
10	RAMON ASO-RED LAKE, N. OF WILLIAMS	D	69.00	12.40	
11	RAWHIDE-SCOTTSDALE	D	69.00	12.00	
12	REACH-SCOTTSDALE	T	230.00	69.00	12.00
13	RED LAKE-E. OF WILLIAMS	D	69.00	21.00	
14	REDONDO-YUMA	D	69.00	12.00	
15	REIDHEAD-SNOWFLAKE	D	69.00	7.20	
16	RINCON-WICKENBURG	D	69.00	7.20	
17	RIO SALADO - TEMPE	D	69.00	12.00	
18	RIO VISTA-SUN CITY	D	69.00	12.00	
19	RIVERSIDE-YUMA	D	69.00	12.00	
20	ROAD RUNNER-PHOENIX	D	69.00	12.00	
21	ROBBINS BUTTE-OUT OF BUCKEYE	D	69.00	12.00	
22	ROCK SPRINGS-ROCK SPRINGS	D	69.00	12.00	
23	ROGERS LAKE-SW. OF FLAGSTAFF	D	69.00	7.20	
24	ROSE GARDEN-PHOENIX	D	69.00	12.00	
25	ROUND VALLEY - KINGMAN	T	230.00		
26	SADDLE MTN-W. OF TONOPAH	D	69.00	12.00	
27	SADDLEBROOK - ORACLE	T	115.00		
28	SAGE VALLEY-VALLE	D	69.00	12.00	
29	SAGUARO 525kV-RED ROCK	A,T	525.00	115.00	34.50
30	SAGUARO 230kv-RED ROCK	A,T	230.00	115.00	12.40
31	SAGUARO 115kV-RED ROCK	A,D	115.00	12.00	
32	SALOME-S.E. OF SALOME	D	69.00	12.00	
33	SAN LUIS-SAN LUIS	D	69.00	12.00	
34	SAN LUIS (MEXICO CONN.)-SAN LUIS	D	69.00	34.50	
35	SAN MANUEL-SAN MANUEL	D	115.00	46.00	
36	SAN MANUEL-SAN MANUEL	D	115.00	12.00	
37	SAN PEDRO-W. OF DOUGLAS	D	69.00	12.00	
38	SANDVIG-FLAGSTAFF	D	69.00	12.00	
39	SANGUINETTI-YUMA	T	69.00		
40	SANTA ROSA-SE. OF MARICOPA	T	230.00	69.00	12.40

Name of Respondent Arizona Public Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SARIVAL-GOODYEAR	D	69.00	12.00	
2	SEDONA-SEDONA	D	69.00	12.00	
3	SELIGMAN COMPRESSER STATION-SELIGMAN	D	230.00		
4	SEXTON-E. OF STANFIELD	D	69.00		
5	SHAW-PHOENIX	D	69.00	12.00	
6	SHEA-SCOTTSDALE	D	69.00	12.00	
7	SHERMAN STREET-PHOENIX	D	69.00	12.00	
8	SHOW LOW-SHOW LOW	D	69.00	12.00	
9	SHOW LOW-SHOW LOW	D	69.00		
10	SHUMWAY-SHOW LOW	D	69.00	12.00	
11	SHUMWAY-SHOW LOW	D	69.00		
12	SKUNK CREEK-GLENDALE	D	69.00	12.00	
13	SNOWFLAKE-SNOWFLAKE	D	69.00	12.00	
14	SOLDIERS TRAIL - FLAGSTAFF	D	69.00	12.00	
15	SONORA - SUPERIOR	D	69.00	21.60	
16	SOUTH O'NEIL - YUMA	T	69.00		
17	SPANISH GARDENS-SURPRISE	D	69.00	12.00	
18	SPIDER WEB - FLAGSTAFF	D	69.00	4.16	
19	STAGECOACH-SCOTTSDALE	D	69.00	12.00	
20	STANTON-S. OF YARNELL	D	69.00	7.20	
21	STARDUST-SUN CITY WEST	D	69.00		
22	STOUT-PHOENIX	D	69.00	12.00	
23	STRAWBERRY-STRAWBERRY	D	69.00	21.00	
24	STURM RUGER-N. OF PRESCOTT	D	69.00	4.16	
25	STURM RUGER-N. OF PRESCOTT	D	69.00	12.40	
26	SUGARLOAF-SNOWFLAKE	T	525.00	69.00	34.50
27	SUNDOG-PRESCOTT	D	69.00	12.00	
28	SUNNYSLOPE-PHOENIX	T	230.00	69.00	
29	SUNNYSLOPE-PHOENIX	D	69.00	12.40	
30	SUNSHINE-WINSLOW	D	69.00	12.00	
31	SURPRISE-SURPRISE	T	230.00	69.00	12.40
32	SURPRISE-SURPRISE	D	69.00	12.00	
33	SWITZER CANYON-FLAGSTAFF	D	69.00	12.00	
34	SYCAMORE-DUGAS	D	69.00	7.20	
35	TABLE MESA-NEW RIVER	D	69.00	7.20	
36	TAPCO-E. OF CLARKDALE	D	69.00	2.40	
37	TARTESSO TEMPORARY - BUCKEYE	D	69.00	12.00	
38	TAT MOMOLI-CASA GRANDE	T	230.00		
39	TEMPE-TEMPE	D	69.00	12.00	
40	TENTH STREET-YUMA	D	69.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	THAYER-THAYER	D	69.00	12.00	
2	THIRTY-SECOND STREET-YUMA	D	69.00	12.00	
3	THOMPSON PEAK-SCOTTSDALE	D	69.00	12.00	
4	TOLTEC-ELOY	D	69.00	12.00	
5	TONALEA-TUBA CITY	D	69.00	21.60	
6	TONOPAH-TONOPAH	D	69.00	12.00	
7	TONTO-PAYSON	D	69.00	21.00	
8	TONTO-PAYSON	D	69.00		
9	TRIBLY WASH - SURPRISE	T	230.00	69.00	12.00
10	TUBA CITY-TUBA CITY	D	69.00	12.00	
11	TURF-PHOENIX	D	69.00	12.00	
12	TUSAYAN-TUSAYAN	D	69.00	12.00	
13	TUSAYAN-TUSAYAN	D	69.00		
14	TUTHILL-BUCKEYE	D	69.00	12.00	
15	TWENTY-THIRD STREET-PHOENIX	D	69.00	12.00	
16	TWIN ARROWS - FLAGSTAFF	T	69.00		
17	UNION HILLS-PHOENIX	D	69.00	12.00	
18	UTTING-SE. OF BOUSE	D	69.00	12.00	
19	VALENCIA-BUCKEYE	D	69.00	12.00	
20	VALLE-WILLIAMS	D	69.00	21.00	
21	VALLEY FARMS-FLORENCE	T	115.00	69.00	12.40
22	VALLEY FARMS-FLORENCE	D	69.00	12.00	
23	VARNEY-SURPRISE	D	69.00	12.00	
24	VERDE-CLARKDALE	T	230.00	69.00	12.40
25	VICKSBURG-S. OF VICKSBURG JUNCTION	D	69.00	12.00	
26	VISTA-CASA GRANDE	D	69.00	12.00	
27	WADDELL-SURPRISE	D	69.00	12.00	
28	WALDRIP - YUMA	T	69.00		
29	WATSON-BUCKEYE	D	69.00	12.00	
30	WELCH - ASHFORK	D	69.00	2.40	
31	WELLFIELD - PRESCOTT VALLEY	D	69.00	12.00	
32	WENDON TEMP - LA PAZ	D	69.00	12.00	
33	WEST PHOENIX-PHOENIX	T	230.00	69.00	12.40
34	WEST PHOENIX-PHOENIX	D	69.00	12.40	
35	WESTBROOK-PEORIA	D	69.00	12.00	
36	WESTWING-SUN CITY	T	525.00	230.00	34.50
37	WESTWING-SUN CITY	T	525.00		
38	WESTWING-SUN CITY	T	525.00		
39	WESTWING-SUN CITY	T	230.00		
40	WESTWING-SUN CITY	D	69.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WESTWING-SUN CITY	T	230.00	69.00	12.40
2	WHITE SPAR-PRESCOTT	D	69.00	12.00	
3	WHITE TANKS-AVONDALE	T	230.00	69.00	12.40
4	WHY - AJO	D	69.00	21.60	
5	WICKENBURG-WICKENBURG	D	69.00	12.00	
6	WILD BURRO-NEW RIVER	D	69.00	7.20	
7	WILD FLOWER-GOODYEAR	D	69.00	12.00	
8	WILHOIT-PRESCOTT	D	69.00	12.00	
9	WILLIAMS-WILLIAMS	D	69.00	12.00	
10	WILLIS - GOODYEAR	D	69.00	12.00	
11	WILLOW LAKE-PRESCOTT	T	230.00	115.00	12.40
12	WILLOW LAKE-PRESCOTT	T	230.00	69.00	12.40
13	WINDMILL-SEDONA	D	69.00	7.20	
14	WINONA-WINONA	D	69.00	12.00	
15	WINSLOW-WINSLOW	D	69.00	12.00	
16	WINTERSBURG - TONOPAH	D	69.00	12.00	
17	WOODRUFF-HOLBROOK	D	69.00	21.00	
18	WOODY MOUNTAIN-FLAGSTAFF	D	69.00	12.00	
19	WUPATKI-FLAGSTAFF	D	69.00	12.00	
20	YALE-PHOENIX	D	69.00	12.00	
21	YARNELL-YARNELL	D	69.00	12.00	
22	YAVAPAI-CHINO VALLEY	T	525.00	230.00	12.40
23	YAVAPAI-CHINO VALLEY	T	230.00	69.00	12.40
24	YORKSHIRE-PHOENIX	D	69.00	12.00	
25	YOUNG'S CANYON - DONEY PARK	T	345.00	69.00	12.00
26	YUCCA-YUMA	T	161.00	69.00	
27	YUMA PALMS TEMP-YUMA	D	69.00	12.00	
28	ZENIFF-SNOWFLAKE	D	69.00		
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
83	2					1
						2
83	2					3
188	1		capacitor bank-69kv	1	48	4
20	1		capacitor bank-69kv	1	5	5
9	1					6
			capacitor bank-69kv	1	48	7
83	2					8
20	1		capacitor bank-69kv	1	7	9
40	2					10
57	2		capacitor bank-69kv	1	14	11
20	1		capacitor bank-12kv	1	4	12
12	1					13
83	2		capacitor bank-69kv	1	22	14
42	1					15
9	1					16
9	1					17
20	1					18
3	1					19
20	1					20
30	1					21
			capacitor bank-115kv	5	49	22
20	1		capacitor bank-69kv	1	14	23
83	2		capacitor bank -12kv	2	10	24
40	2		capacitor bank-69kv	2	22	25
20	1					26
83	2					27
			capacitor bank-69kv	1	14	28
						29
112	1	1				30
9	1					31
10	1					32
15	1					33
13	1					34
20	1					35
83	2					36
267	2					37
20	1					38
83	2					39
7	1		capacitor bank-69kv	1	10	40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
167	4					1
522	3					2
125	3		capacitor bank-69kv	1	48	3
41	1					4
125	3					5
2	1					6
83	2					7
40	2		capacitor bank-12kV	4	14	8
100	1					9
50	1	1				10
20	1					11
40	2					12
						13
83	2					14
83	2					15
83	2					16
40	2					17
						18
38	2					19
1002	6	1	capacitor bank 525kv	1	569	20
			shunt reactor 525kV	4	167	21
203	1		capacitor bank 345kv	2	870	22
143	1					23
150	2					24
83	2		capacitor bank -12kV	2	7	25
40	2		capacitor bank -12kV	2	7	26
355	2					27
40	2		capacitor bank-69kv	2	36	28
83	2		capacitor bank-69kv	1	14	29
83	2		capacitor bank-69kv	1	29	30
9	1					31
83	2					32
						33
						34
40	2		capacitor bank-12kv	4	12	35
20	1					36
20	1		capacitor bank 69kv	1	7	37
40	2					38
40	2		capacitor bank-69kV	1	11	39
			capacitor bank-12kV	2	6	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
125	3					1
355	2					2
40	2		capacity bank-69kV	2	14	3
20	1					4
83	2		capacitor bank-12kv	2	7	5
			capacitor bank 69kV	1	29	6
3	1					7
83	2		capacitor bank -12kv	2	7	8
			capacitor bank 69kv	1	29	9
564	3					10
125	3		capacitor bank-69kV	1	48	11
22	1					12
40	2					13
83	2		capacitor bank-12kv	2	10	14
						15
4	1					16
83	2		capacitor bank-12kv	2	10	17
40	2		capacitor bank-69kv	1	14	18
83	2		capacitor bank-12kv	2	7	19
20	1					20
42	1					21
83	2		capacitor bank-12kv	2	4	22
123	3		capacitor bank-69kv	1	48	23
			capacitor bank-69kv	3	22	24
	1					25
269	3	4	shunt reactor 525kV	1	190	26
			capacitor bank-525kv	1	536	27
83	2		capacitor bank-12kV	2	7	28
125	3					29
100	2					30
41	1		capacitor bank-12kV	2	5	31
41	1		capacitor bank-12kV	1	5	32
41	1		capacitor bank-12kV	2	14	33
40	2					34
20	1	1				35
376	2					36
83	2		capacitor bank-69kv	1	48	37
40	2					38
83	2					39
41	1		capacitor bank-12kv	1	4	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
83	2		capacitor bank-12kv	4	10	1
41	1		capacitor bank-12kv	4	10	2
						3
20	1					4
83	2		capacitor bank-69kv	1	29	5
	1	2				6
20	1		capacitor bank-69kv	1	7	7
20	1		capacitor bank-69kv	2	22	8
83	2		capacitor bank-69kv	2	29	9
83	2		capacitor bank-12kv	2	7	10
1025	3	1	shunt reactor 525kv	3	125	11
1400	2	1	shunt reactor 345kV	3	200	12
106	2		shunt reactor - 230V	2	200	13
167	4		capacitor bank 12kv	4	10	14
10	1					15
42	1					16
188	1					17
41	1					18
200	2					19
83	2		capacitor bank-69kv	2	30	20
83	2		capacitor bank 12kv	2	8	21
40	2		capacitor bank-69kv	1	14	22
100	2					23
9	1					24
						25
41	1					26
	2					27
41	1					28
125	3		capacitor bank-12kV	3	11	29
20	1					30
41	1					31
	1					32
	1					33
18	1					34
125	3					35
10	1					36
						37
41	1					38
20	1					39
10	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
83	2					2
83	2		capacitor bank-69kv	1	29	3
20	1		capacitor bank-12kv	2	5	4
83	2					5
						6
10	1					7
	1					8
40	2					9
						10
83	2		capacitor bank-12kV	2	7	11
125	3					12
40	2					13
125	3					14
83	2					15
41	1					16
9	1					17
20	1					18
9	1					19
						20
9	1					21
36	2		capacitor bank-69kV	2	29	22
	1					23
20	1					24
6	1					25
						26
188	1					27
83	2		capacitor bank-69kV	1	35	28
167	4		capacitor bank-12kv	8	19	29
83	2					30
83	2					31
376	2					32
41	1					33
40	2					34
83	2					35
40	2					36
	1					37
83	2		capacitor bank-12kV	2	7	38
83	2					39
	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
16	1					2
83	2					3
83	2					4
83	2					5
188	1					6
125	3		capacitor bank-69kV	1	48	7
						8
41	1		capacitor bank-69kv	2	14	9
125	3		capacitor bank -12kv	4	10	10
	1					11
188	1	1				12
						13
1	2					14
7	1					15
			capacitor bank 525kv	4	4,235	16
			shunt reactor 525kv	10	646	17
83	2					18
83	2					19
600	1	1				20
9	1		capacitor bank-69kv	1	11	21
83	2		capacitor bank-69kv	1	48	22
3	1					23
50	1					24
83	2					25
9	1					26
9	1	1	capacitor bank-12kv	4	10	27
50	1	1				28
	1					29
			shunt reactor 525kv	2	380	30
			capacitor bank 525kV	2	1,738	31
6	1					32
20	1					33
	1					34
600	1		shunt reactor 525kV	4	328	35
509	6		capacitor bank 525kv	2	979	36
83	2					37
40	2		capacitor bank 12kv	2	5	38
16	1					39
355	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
			capacitor bank 230kv	2	314	1
			capacitor bank 69kv	1	48	2
						3
125	3					4
4	1					5
	1					6
	1					7
188	1	1				8
83	2					9
20	1					10
20	1					11
						12
40	2					13
125	3		capacitor bank-12kV	2	7	14
5	1					15
16	1					16
9	1					17
20	1					18
41	1					19
83	2					20
20	1					21
13	1	1				22
36	2					23
84	1					24
41	1					25
	1					26
1872	3		shunt reactor-525kV	1	190	27
2025	3	1				28
752	4		capacitor bank 230kv	3	159	29
83	2					30
4	1					31
20	1					32
9	1					33
83	2		capacitor bank-69kV	2	29	34
			capacitor bank-12kV	2	10	35
2	3					36
	1					37
162	2					38
16	1					39
3	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
40	2					2
41	1					3
40	2		capacitor bank-69kv	2	22	4
16	1					5
83	2					6
188	1					7
9	1					8
83	2					9
	1					10
83	2					11
376	2		capacitor bank-69kV	1	48	12
4	1					13
20	1					14
	1					15
	1					16
83	2					17
83	2					18
9	1					19
83	2					20
	3					21
16	1					22
	1					23
83	2					24
						25
20	1		capacitor bank-69kv	1	7	26
						27
	1					28
1450	2		shunt reactor - 525V	4	167	29
896	2	1				30
22	1	2	capacitor bank-115kv	2	49	31
20	1		capacitor bank-69kv	2	7	32
40	2		capacitor bank-69kv	1	7	33
20	1		capacitor bank-34.5k	1	4	34
65	4					35
138	5					36
6	1					37
40	2					38
						39
355	2		capacitor bank 230kv	2	94	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
83	2		capacitor bank-69kV	2	29	1
40	2					2
						3
						4
83	2					5
83	2					6
83	2					7
40	2		capacitor bank-12kv	4	10	8
			capacitor bank-69kV	2	22	9
9	1		capacitor bank-12kv	2	6	10
			capacitor bank-69kV	2	14	11
83	2					12
40	2					13
20	1					14
	2					15
						16
83	2					17
	1					18
83	2					19
	1					20
83	2					21
83	2					22
9	1					23
5	3					24
20	1					25
269	3	1	capacitor bank-69kv	1	14	26
40	2		capacitor bank-69kv	1	7	27
355	2					28
83	2		capacitor bank-69kv	1	43	29
2	3					30
564	3		capacitor bank-69kv	1	53	31
125	3					32
34	2					33
	1					34
	1					35
	2					36
9	1					37
						38
83	2					39
40	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
83	2					2
83	2					3
41	1		capacitor bank 69kv	2	14	4
1	2					5
16	1		capacitor bank-69kv	1	10	6
40	2		capacitor bank-69kv	1	7	7
			capacitor bank-21.6	4	10	8
188	1					9
20	1		capacitor bank - 12V	2	6	10
83	2					11
9	1		capacitor bank-12kv	6	7	12
			capacitor bank-69kV	1	7	13
41	1					14
83	2					15
						16
83	2					17
11	1					18
40	2					19
2	3					20
188	1					21
41	1					22
41	1					23
200	2		capacitor bank-69kV	4	29	24
20	1					25
83	2		capacitor bank-12kv	4	14	26
83	2					27
						28
83	2					29
	1					30
20	1					31
10	1					32
564	3		capacitor bank-69kv	1	35	33
83	2		capacitor bank-12kV	4	10	34
41	1					35
4500	9	4				36
			shunt reactor 525kV	3	571	37
			capacitor bank 525kv	1	236	38
			shunt reactor 230kV	2	212	39
41	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
376	2					1
40	2		capacitor bank-12kv	2	12	2
376	2					3
3	1					4
36	2		capacitor bank-69kv	1	12	5
	1					6
83	2					7
3	1					8
16	2		capacitor bank-69kv	1	6	9
41	1		capacitor bank - 69V	1	14	10
166	2		shunt reactor 230kV	1	25	11
376	2					12
	1					13
3	1					14
20	2					15
18	1					16
4	1					17
18	1		capacitor bank 69kv	1	7	18
	1					19
83	2		capacitor bank-12kv	4	10	20
9	1					21
672	2					22
100	1					23
20	1					24
150	1		capacitor bank 69kV	1	14	25
84	1		capacitor bank-69kv	1	25	26
20	1					27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) X An Original (2) _ A Resubmission	03/17/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 426 Line No.: 1 Column: a

STATEMENT OF CO-OWNERSHIP AS DESCRIBED IN INSTRUCTION #6, PAGE 427 AND AS NOTED ON PAGE 426. NONE OF THE CO-OWNERS IS AN ASSOCIATED COMPANY

(A) CO-OWNERSHIP ON:
CEDAR MOUNTAIN
CHOLLA SWITCHYARD
HOODOO WASH
FOUR CORNERS SWITCHYARD
MORGAN SUBSTATION
NAVAJO SWITCHYARD
NORTH GILA
PINNACLE PEAK
WESTWING 525KV SWITCHYARD
WESTWING 230KV SWITCHYARD

(1) CO-OWNERS OF CEDAR MOUNTAIN ARE SALT RIVER PROJECT, TUCSON ELECTRIC POWER COMPANY, UNITED STATES

(2) CO-OWNER OF CHOLLA SWITCHYARD IS PACIFICORP

(3) CO-OWNERS OF HOODOO WASH ARE IMPERIAL IRRIGATION DISTRICT, SAN DEIGO GAS & ELECTRIC

(4) CO-OWNERS OF FOUR CORNER SWITCHYARD ARE SALT RIVER PROJECT, EL PASO ELECTRIC COMPANY, PUBLIC SERVICE OF NEW MEXICO, SOUTHERN CALIFORNIA EDISON, AND TUCSON ELECTRIC POWER COMPANY

(5) CO-OWNER OF MORGAN SUBSTATION IS SALT RIVER PROJECT

(6) CO-OWNERS OF NAVAJO SWITCHYARD ARE SALT RIVER PROJECT, NEVADA POWER COMPANY, UNITED STATES, TUCSON ELECTRIC POWER COMPANY, AND LOS ANGELES DEPARTMENT OF WATER AND POWER

(7) CO-OWNERS OF NORTH GILA SUBSTATION ARE SAN DIEGO GAS & ELECTRIC AND IMPERIAL IRRIGATION DISTRICT

(8) CO-OWNER OF PINNACLE PEAK 500KV SUBSTATION AND 230KV NORTH SUBSTATION IS SALT RIVER PROJECT

(9) CO-OWNERS OF WESTWING 525KV SWITCHYARD ARE SALT RIVER PROJECT, EL PASO ELECTRIC COMPANY, TUCSON ELECTRIC POWER COMPANY, PUBLIC SERVICE COMPNANY OF NEW MEXICO, AND UNITED STATES

(10) CO-OWNERS OF WESTWING 230KV SWITCHYARD ARE SALT RIVER PROJECT, EL PASO ELECTRIC COMPANY, PUBLIC SERVICE COMPANY OF NEW MEXICO, AND UNITED STATES

(B) EXPENSES FOR THE OPERATION, MAINTENANCE, AND RENTS ARE NOT SEGREGATED IN THE COMPANY'S BOOKS FOR EACH SUBSTATION

(C) SUBSTATIONS THAT APS DOES NOT OWN THE MAJORITY PORTION AND IS NOT OPERATING AGENT ARE NOT LISTED ON THIS REPORT

Name of Respondent Arizona Public Service Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 03/17/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 426 Line No.: 1 Column: b

A-ATTENDED
D-DISTRIBUTION
T-TRANSMISSION

Schedule Page: 426 Line No.: 1 Column: c

VOLTAGE IS EXPRESSED IN KV

Schedule Page: 426 Line No.: 1 Column: d

VOLTAGE IS EXPRESSED IN KV

Schedule Page: 426 Line No.: 1 Column: e

VOLTAGE IS EXPRESSED IN KV

Schedule Page: 426 Line No.: 1 Column: k

CAPACITY IS EXPRESSED IN MVAR

Schedule Page: 426.2 Line No.: 25 Column: f

0.25 MVa

Schedule Page: 426.3 Line No.: 6 Column: f

0.3 MVa

Schedule Page: 426.3 Line No.: 27 Column: f

0.81 MVa

Schedule Page: 426.3 Line No.: 32 Column: f

0.1 MVa

Schedule Page: 426.3 Line No.: 33 Column: f

0.1 MVa

Schedule Page: 426.4 Line No.: 8 Column: f

0.373 MVa

Schedule Page: 426.4 Line No.: 23 Column: f

0.1 MVa

Schedule Page: 426.4 Line No.: 37 Column: f

0.1 MVa

Schedule Page: 426.4 Line No.: 40 Column: f

0.1 MVa

Schedule Page: 426.5 Line No.: 11 Column: f

0.1 MVa

Schedule Page: 426.5 Line No.: 29 Column: f

0.1 MVa

Schedule Page: 426.5 Line No.: 34 Column: f

0.1 MVa

Schedule Page: 426.6 Line No.: 6 Column: f

0.1 MVa

Schedule Page: 426.6 Line No.: 7 Column: f

0.1 MVa

Schedule Page: 426.6 Line No.: 26 Column: f

0.1 MVa

Schedule Page: 426.6 Line No.: 37 Column: f

0.56 MVa

Schedule Page: 426.7 Line No.: 10 Column: f

0.56 MVa

Schedule Page: 426.7 Line No.: 15 Column: f

0.1 MVa

FOOTNOTE DATA

Schedule Page: 426.7 Line No.: 16 Column: f

0.01 MVa

Schedule Page: 426.7 Line No.: 21 Column: f

0.75 MVa

Schedule Page: 426.7 Line No.: 23 Column: f

0.025 MVa

Schedule Page: 426.7 Line No.: 28 Column: f

0.25 MVa

Schedule Page: 426.8 Line No.: 15 Column: f

0.5 MVa

Schedule Page: 426.8 Line No.: 18 Column: f

0.1 MVa

Schedule Page: 426.8 Line No.: 20 Column: f

0.5 MVa

Schedule Page: 426.8 Line No.: 34 Column: f

0.1 MVa

Schedule Page: 426.8 Line No.: 35 Column: f

0.25 MVa

Schedule Page: 426.8 Line No.: 36 Column: f

0.2 MVa

Schedule Page: 426.9 Line No.: 30 Column: f

0.15 MVa

Schedule Page: 426.10 Line No.: 6 Column: f

0.25 MVa

Schedule Page: 426.10 Line No.: 13 Column: f

0.5 MVa

Schedule Page: 426.10 Line No.: 19 Column: f

0.1 MVa

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	03/17/2016	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Common stock dividends	Pinnacle West Capital Corporation	438	266,900,000
3	Share of estimated income taxes	Pinnacle West Capital Corporation	236	14,830,659
4	Share of withholding and payroll taxes	Pinnacle West Capital Corporation	236,241,408	246,325,601
5	Share of pension and other post retirement			
6	benefits contributions	Pinnacle West Capital Corporation	228.3	100,596,034
7	Share of employee benefits (excluding pension and			
8	OPEB contributions)	Pinnacle West Capital Corporation	228.3,925,926	138,576,761
9	Employee programs payroll deductions	Pinnacle West Capital Corporation	143,232,242	67,794,523
10	Shared services	Pinnacle West Capital Corporation	various	28,599,927
11	Compensation paid in stock	Pinnacle West Capital Corporation	various	22,223,843
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Shared services	Pinnacle West Capital Corporation	various	13,253,865
22	Four Corners Capital	Pinnacle West Capital Corporation	131	2,666,605
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 4 Column: d

Includes employer share of FICA allocated at 7%

Schedule Page: 429 Line No.: 8 Column: d

Includes benefits allocated at 37% & injuries and damages allocated at 1%

Schedule Page: 429 Line No.: 10 Column: d

Includes corporate allocations at 100.0% and governance allocations at 99.5%

Schedule Page: 429 Line No.: 11 Column: d

Includes governance allocations at 99.5%

INDEX

Schedule	Page No.

Schedule	Page No.

INDEX (continued)

Schedule | Page No.

Schedule | Page No.

Document Content(s)