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

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

XXXIII. MODIFICATION TO ENVIRONMENTAL IMPROVEMENT SURCHARGE

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

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

XXXIV. TRANSMISSION COST ADJUSTMENT MECHANISM

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

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

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

XXXV. CHALLENGES TO DECISION NOS. 75859 AND 75932

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

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

XXXVI. POWER SUPPLY ADJUSTOR AUDIT

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

XXXVII. COMPLIANCE MATTERS

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

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

XXXVIII. FORCE MAJEURE PROVISION

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

XXXIX. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

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

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

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

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

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

XL. MISCELLANEOUS PROVISIONS

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

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

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

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

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

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

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

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

SIGNATURE PAGE

ARIZONA CORPORATION COMMISSION

By: ______________________

Name: Elijah Abinah

Title: Acting Director, Utilities Division

Date: March 24, 2017

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

SIGNATURE PAGE

Arizona Public Service Company

By: Barbara Lockwood

Name: Barbara Lockwood

Title: Vice President, Regulation

Date: March 24, 2017

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

SIGNATURE PAGE

Residential Utility Consumer Office

By: David Tenney

Name: David Tenney

Title: Director

Date: 3/24/17

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

SIGNATURE PAGE

[Arizona Utility Ratepayer Alliance]

By: ______________________

Name: Patrick J Quinn

Title: Managing Partner

Date: March 24, 2017

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

SIGNATURE PAGE

FEDERAL EXECUTIVE AGENCIES

By:

Name: Lanny L. Zieman, Captain, USAF

Title: Utilities Litigation Attorney

Date: 24 March 2017

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

SIGNATURE PAGE

ARIZONA SOLAR DEPLOYMENT ALLIANCE

By: ______________________

Name: SEAN M. SEITZ

Title: PRESIDENT

Date: MARCH 24, 2017

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

SIGNATURE PAGE

[INSERT PARTY NAME/COMPANY]

By: Thomas A. Harris

Name: Tom Harris

Title: Treasurer, AriSEIA

Date: Mar. 24, 2017

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

SIGNATURE PAGE

Vote Solar
[INSERT PARTY NAME/COMPANY]

By: ____________________

Name: Adam Browning

Title: Executive Director

Date: 3/24/17

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

SIGNATURE PAGE

Solar Energy Industries Association

By: ____________________

Name: Sean Gallagher

Title: Vice-President State Affairs

Date: 3/24/17

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

SIGNATURE PAGE

ENERGY FREEDOM COALITION OF AMERICA

By: ______________________

Name: Court S. Rich

Title: Attorney for Energy Freedom Coalition of America, LLC

Date: 3/27/17

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

SIGNATURE PAGE

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

By: ______________________

Name: Timothy M. Hogan

Title: Attorney

Date:3/23/17

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

SIGNATURE PAGE

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION

By:

Name: Stan Barnes

Title: President

Date: March 24, 2017

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

SIGNATURE PAGE

WESTERN RESOURCE ADVOCATES

By: John Nielsen

Name: John Nielsen

Title: Clean Energy Program Director

Date: 3/24/2017

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

SIGNATURE PAGE

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

By: Scott Wakefield

Name: Scott Wakefield

Title: Attorney

Date: March 24, 2017

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

LUBIN & ENOCH, P.C.

By: ______________________________

Name: Nicholas J. Enoch, Esq.

Title: Attorney for Intervenors

IBEW Locals 387 & 769

Date: March 24, 2017

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

SIGNATURE PAGE

FREEPORT MINERALS CORPORATION

By: Michael McElrath

Name: Michael McElrath

Title: Director Energy

Date: March 24, 2017

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

SIGNATURE PAGE

[INSERT PARTY NAME/COMPANY]

By: ______________________

Name: Cynthia Zwick

Title: Executive Director,
Arizona Community Action Assoc.

Date: March 24, 2017

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

SIGNATURE PAGE

[INSERT PARTY NAME/COMPANY]

By: K Boehm

Name: KURT Boehm

Title: ATTORNEY, the Kroger Co.

Date: 3/24/2017

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

SIGNATURE PAGE

ARIZONA INVESTMENT COUNCIL

By: ______________

Name: GaryYaquinto

Title: President& CEO

Date: 3/24/2017

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

SIGNATURE PAGE

Property Owners & Residents Association
(PORA) Sun City West

By: Al Gervenack

Name: Al Gervenack

Title: Director, Board of Directors

Date: March 24, 2017

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

SIGNATURE PAGE

[SUN CITY HOME OWNERS ASSOCIATION (SCHOA)]

By: Greg Eisert

Name: GREG EISERT

Title: Director, Chairman of Government Affairs

Date: 24 March 2017

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

SIGNATURE PAGE

REP America d/b/a ConservAmerica

By: [signature]

Name: Timothy J Schs

Title: Attorney for ConservAmerica

Date: 3/24/17

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

SIGNATURE PAGE

Constellation New Energy, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

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

SIGNATURE PAGE

Direct Energy Business, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

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

SIGNATURE PAGE

Calpine Energy Solutions, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

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

SIGNATURE PAGE

[Arizona Competitive Power Alliance]

By: ______________________

Name: Greg Patterson

Title: AzCPA Director

Date: March 24, 2017

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

SIGNATURE PAGE

CITY OF COOLIDGE

By: D. M. Fitzgibbons

Name: Denis M. Fitzgibbons

Title: City of Attorney

Date: March 24, 2017

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

SIGNATURE PAGE

Granite Creek Farms LLC
Granite Creek Power & Gas LLC

By: ________________

Name: Thomas E Stewart____________

Title: General Manager______________

Date:3/26/2017____________________

Settlement Agreement Appendix Index

A	Depreciation Rates
B	Annual Nuclear Decommissioning Expense
C	PSA Plan of Administration
D	Adjustors Transferred to Base Rates
E	TEAM Plan of Administration
F	R-XS, R-Basic, R-Basic Large, TOU-E, R-2, R-3 Rate Schedules, R-Tech Pilot Rate
G	Residential and Commercial Rate Summary
H	RCP Rate Rider and POA, EPR-6, and EPR-6 Legacy Rate Rider
I	E-32L, E-32L TOU, XHLF Rate Schedule
J	Service Schedule 9
K	AG-X Rate Schedule
L	Revenue Spread/Targets
M	Service Schedule 1
N	Service Schedule 3
O	LFCR Plan of Administration
P	EIS Plan of Administration
Q	TCA Plan of Administration
R	Compliance Requirements Eliminated or Waived

Appendix A

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	2.52%	0.30%	2.82%	5.01%	0.42%	5.43%
312.00 Boiler Plant Equipment	2.17%	0.32%	2.49%	3.78%	0.39%	4.17%
314.00 Turbogenerator Units	2.51%	0.33%	2.84%	4.45%	0.50%	4.95%
315.00 Accessory Electric Equipment	2.27%	0.34%	2.61%	4.50%	0.47%	4.97%
316.00 Miscellaneous Power Plant Equipment	2.46%	0.33%	2.79%	4.77%	0.59%	5.36%
Total Steam Production Plant	2.27%	0.32%	2.59%	4.08%	0.42%	4.50%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	0.96%	0.02%	0.98%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	0.77%	0.06%	0.83%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	0.89%	0.03%	0.92%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	0.39%	0.01%	0.40%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.30%	0.05%	1.35%
Total Nuclear Production Plant	1.42%	0.03%	1.45%	0.84%	0.03%	0.87%
OTHER PRODUCTION						
341.00 Structures and Improvements	3.04%	-0.09%	2.95%	3.60%	0.26%	3.86%
342.00 Fuel Holders, Products and Accessories	3.14%	-0.15%	2.99%	3.62%	0.19%	3.81%
343.00 Prime Movers	2.40%	-0.10%	2.30%	3.28%	0.15%	3.43%
344.00 Generators and Devices	3.30%	-0.32%	2.98%	3.86%	0.12%	3.98%
345.00 Accessory Electric Equipment	3.11%	-0.06%	3.05%	3.71%	0.24%	3.95%
346.00 Miscellaneous Power Plant Equipment	3.35%	-0.15%	3.20%	4.08%	0.21%	4.29%
Total Other Production Plant	3.02%	-0.22%	2.80%	3.67%	0.15%	3.82%
TRANSMISSION PLANT						
352.02 Structures and Improvements	2.67%		2.67%	2.51%		2.51%
353.00 Station Equipment	2.31%	0.11%	2.42%	1.91%	0.09%	2.00%
354.00 Towers and Fixtures	1.84%		1.84%	1.78%		1.78%
355.00 Poles and Fixtures	1.86%	0.37%	2.23%	1.85%	0.37%	2.22%
356.00 Overhead Conductors and Devices	1.75%	0.33%	2.08%	1.74%	0.33%	2.07%
Total Transmission Plant	2.29%	0.11%	2.40%	1.91%	0.09%	2.00%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.57%	0.07%	1.64%	1.58%	0.08%	1.66%
362.00 Station Equipment	2.19%	-0.20%	1.99%	2.20%	0.08%	2.28%
363.00 Storage Battery Equipment	6.67%		6.67%	8.79%		8.79%
364.01 Poles, Towers and Fixtures - Wood	2.29%	-0.02%	2.27%	2.10%	0.19%	2.29%
364.02 Poles, Towers and Fixtures - Steel	2.55%	0.26%	2.81%	1.95%	0.19%	2.14%
365.00 Overhead Conductors and Devices	1.98%	-0.08%	1.90%	1.92%	0.20%	2.12%
366.00 Underground Conduit	1.57%	0.08%	1.65%	1.57%	0.17%	1.74%
367.00 Underground Conductors and Devices	2.63%	0.09%	2.72%	2.34%	0.20%	2.54%
368.00 Line Transformers	1.68%	0.07%	1.75%	1.70%	0.06%	1.76%
369.00 Services	2.20%	0.10%	2.30%	1.68%	0.33%	2.01%
370.01 Meters - Electronic	3.68%		3.68%	5.52%	-0.03%	5.49%
370.03 Meters - AMI	3.82%		3.82%	4.84%		4.84%
371.00 Installations on Customers' Premises	2.34%	0.34%	2.68%	2.11%	0.31%	2.42%
373.00 Street Lighting and Signal Systems	1.72%	0.13%	1.85%	1.72%	0.18%	1.90%
Total Distribution Plant	2.25%	0.05%	2.30%	2.14%	0.16%	2.30%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.19%	0.13%	2.32%	2.52%	0.17%	2.69%
391.CM Office Furn. and Equip. - Computer	12.08%	0.02%	12.10%	12.86%	0.02%	12.88%
397.00 Communication Equipment	5.35%		5.35%	4.83%		4.83%
Total Depreciable	6.30%	0.04%	6.34%	6.40%	0.06%	6.46%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Current Net Salvage	Current Total	Proposed (at 12/31/2015) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
Amortizable						
391.FE Office Furn. and Equip. - Furniture	← 20 Year Amortization →			← 20 Year Amortization →		
393.00 Stores Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
395.00 Laboratory Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
398.00 Miscellaneous Equipment	← 24 Year Amortization →			← 24 Year Amortization →		
Total Amortizable	4.86%		4.86%	4.86%		4.86%
Total General Plant	6.07%	0.04%	6.11%	6.15%	0.05%	6.20%
TOTAL UTILITY	2.42%	0.03%	2.45%	2.61%	0.16%	2.77%
STEAM PRODUCTION (by Unit)						
Cholla						
311.00 Structures and Improvements	2.85%	0.14%	2.99%	7.05%	0.50%	7.55%
312.00 Boiler Plant Equipment	3.56%	0.25%	3.81%	7.02%	0.57%	7.59%
314.00 Turbogenerator Units	3.53%	0.18%	3.71%	6.64%	0.46%	7.10%
315.00 Accessory Electric Equipment	2.55%	0.14%	2.69%	6.10%	0.43%	6.53%
316.00 Miscellaneous Power Plant Equipment	3.00%	0.20%	3.20%	7.37%	0.55%	7.92%
Total Cholla	3.36%	0.22%	3.58%	6.90%	0.54%	7.44%
Cholla Unit 1						
311.00 Structures and Improvements	3.60%	0.17%	3.77%	5.36%	0.44%	5.80%
312.00 Boiler Plant Equipment	4.22%	0.26%	4.48%	6.04%	0.65%	6.69%
314.00 Turbogenerator Units	4.59%	0.24%	4.83%	6.37%	0.58%	6.95%
315.00 Accessory Electric Equipment	3.65%	0.19%	3.84%	5.48%	0.48%	5.96%
316.00 Miscellaneous Power Plant Equipment	3.45%	0.19%	3.64%	5.15%	0.45%	5.60%
Total Cholla Unit 1	4.22%	0.25%	4.47%	6.02%	0.61%	6.63%
Cholla Unit 3						
311.00 Structures and Improvements	2.19%	0.10%	2.29%	7.02%	0.46%	7.48%
312.00 Boiler Plant Equipment	3.40%	0.25%	3.65%	7.28%	0.55%	7.83%
314.00 Turbogenerator Units	3.04%	0.15%	3.19%	6.72%	0.39%	7.11%
315.00 Accessory Electric Equipment	2.16%	0.12%	2.28%	5.99%	0.42%	6.41%
316.00 Miscellaneous Power Plant Equipment	2.48%	0.15%	2.63%	7.24%	0.52%	7.76%
Total Cholla Unit 3	3.15%	0.21%	3.36%	7.05%	0.51%	7.56%
Cholla Common						
311.00 Structures and Improvements	2.94%	0.15%	3.09%	7.19%	0.52%	7.71%
312.00 Boiler Plant Equipment	3.32%	0.25%	3.57%	7.27%	0.60%	7.87%
314.00 Turbogenerator Units	2.67%	0.13%	2.80%	8.50%	0.63%	9.13%
315.00 Accessory Electric Equipment	2.96%	0.18%	3.14%	7.29%	0.47%	7.76%
316.00 Miscellaneous Power Plant Equipment	3.16%	0.22%	3.38%	7.89%	0.59%	8.48%
Total Cholla Common	3.12%	0.20%	3.32%	7.31%	0.56%	7.87%
Four Corners						
311.00 Structures and Improvements	1.35%	0.51%	1.86%	2.36%	0.26%	2.62%
312.00 Boiler Plant Equipment	0.85%	0.37%	1.22%	1.52%	0.26%	1.78%
314.00 Turbogenerator Units	0.95%	0.42%	1.37%	1.60%	0.30%	1.90%
315.00 Accessory Electric Equipment	1.40%	0.56%	1.96%	2.59%	0.39%	2.98%
316.00 Miscellaneous Power Plant Equipment	1.09%	0.29%	1.38%	2.30%	0.39%	2.69%
Total Four Corners	0.94%	0.39%	1.33%	1.69%	0.28%	1.97%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Four Corners Units 4-5						
311.00 Structures and Improvements	0.98%	0.52%	1.50%	1.75%	0.31%	2.06%
312.00 Boiler Plant Equipment	0.77%	0.36%	1.13%	1.40%	0.24%	1.64%
314.00 Turbogenerator Units	0.92%	0.43%	1.35%	1.55%	0.30%	1.85%
315.00 Accessory Electric Equipment	1.06%	0.57%	1.63%	2.12%	0.41%	2.53%
316.00 Miscellaneous Power Plant Equipment	0.54%	0.18%	0.72%	2.02%	0.40%	2.42%
Total Four Corners Units 4-5	0.80%	0.38%	1.18%	1.50%	0.26%	1.76%
Four Corners Common						
311.00 Structures and Improvements	2.23%	0.48%	2.71%	3.81%	0.16%	3.97%
312.00 Boiler Plant Equipment	2.09%	0.49%	2.58%	3.44%	0.44%	3.88%
314.00 Turbogenerator Units	1.65%	0.28%	1.93%	2.87%	0.27%	3.14%
315.00 Accessory Electric Equipment	2.39%	0.53%	2.92%	3.93%	0.36%	4.29%
316.00 Miscellaneous Power Plant Equipment	2.50%	0.58%	3.08%	3.03%	0.34%	3.37%
Total Four Corners Common	2.21%	0.50%	2.71%	3.50%	0.35%	3.85%
Navajo Units 1-3						
311.00 Structures and Improvements	3.34%	0.24%	3.58%	3.78%	0.20%	3.98%
312.00 Boiler Plant Equipment	3.42%	0.28%	3.70%	3.52%	0.19%	3.71%
314.00 Turbogenerator Units	2.71%	0.20%	2.91%	2.72%	0.15%	2.87%
315.00 Accessory Electric Equipment	2.93%	0.21%	3.14%	3.06%	0.17%	3.23%
316.00 Miscellaneous Power Plant Equipment	3.75%	0.29%	4.04%	4.19%	0.29%	4.48%
Total Navajo Units 1-3	3.33%	0.26%	3.59%	3.49%	0.19%	3.68%
Ocotillo Units 1-2						
311.00 Structures and Improvements	4.91%	0.88%	5.79%	10.65%	2.28%	12.93%
312.00 Boiler Plant Equipment	3.41%	0.65%	4.06%	8.89%	1.97%	10.86%
314.00 Turbogenerator Units	4.74%	0.88%	5.62%	9.88%	2.25%	12.13%
315.00 Accessory Electric Equipment	4.55%	0.84%	5.39%	12.68%	2.76%	15.44%
316.00 Miscellaneous Power Plant Equipment	5.80%	1.10%	6.90%	13.34%	2.76%	16.10%
Total Ocotillo Units 1-2	4.30%	0.80%	5.10%	10.17%	2.23%	12.40%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	0.96%	0.02%	0.98%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	0.77%	0.06%	0.83%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	0.89%	0.03%	0.92%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	0.39%	0.01%	0.40%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.30%	0.05%	1.35%
Total Palo Verde	1.42%	0.03%	1.45%	0.84%	0.03%	0.87%
Palo Verde Unit 1						
321.00 Structures and Improvements	1.13%		1.13%	0.18%	0.00%	0.19%
322.00 Reactor Plant Equipment	1.45%	0.04%	1.49%	0.60%	0.01%	0.62%
323.00 Turbogenerator Units	1.41%	0.02%	1.43%	0.79%	0.05%	0.83%
324.00 Accessory Electric Equipment	1.11%	0.01%	1.12%	0.19%	0.00%	0.20%
325.00 Miscellaneous Power Plant Equipment	1.29%	0.02%	1.31%	0.40%	0.04%	0.43%
Total Palo Verde Unit 1	1.34%	0.03%	1.37%	0.50%	0.01%	0.51%
Palo Verde Unit 2						
321.00 Structures and Improvements	1.20%	0.01%	1.21%	0.37%	0.00%	0.37%
322.00 Reactor Plant Equipment	1.52%	0.08%	1.60%	0.96%	0.06%	1.02%
323.00 Turbogenerator Units	1.41%	0.01%	1.42%	1.11%	0.03%	1.14%
324.00 Accessory Electric Equipment	1.25%	0.01%	1.26%	0.47%	0.01%	0.48%
325.00 Miscellaneous Power Plant Equipment	1.45%	0.02%	1.47%	0.69%	0.03%	0.72%
Total Palo Verde Unit 2	1.41%	0.05%	1.46%	0.82%	0.03%	0.85%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
Account Description	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Palo Verde Unit 3						
321.00 Structures and Improvements	1.22%		1.22%	0.29%	0.00%	0.29%
322.00 Reactor Plant Equipment	1.56%	0.05%	1.61%	0.81%	0.09%	0.90%
323.00 Turbogenerator Units	1.48%	0.02%	1.50%	0.81%	0.01%	0.83%
324.00 Accessory Electric Equipment	1.24%	0.01%	1.25%	0.39%	0.01%	0.41%
325.00 Miscellaneous Power Plant Equipment	1.36%	0.02%	1.38%	0.55%	0.04%	0.59%
Total Palo Verde Unit 3	1.44%	0.03%	1.47%	0.66%	0.05%	0.71%
Palo Verde Water Reclamation						
321.00 Structures and Improvements	1.69%	0.02%	1.71%	2.05%	0.03%	2.08%
322.00 Reactor Plant Equipment	2.01%	0.03%	2.04%	2.92%	0.04%	2.96%
323.00 Turbogenerator Units	1.45%	0.01%	1.46%	1.43%	0.17%	1.60%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	1.43%	0.05%	1.48%	2.19%	0.01%	2.20%
Total Palo Verde Water Reclamation	1.69%	0.02%	1.71%	2.05%	0.04%	2.09%
Palo Verde Common						
321.00 Structures and Improvements	1.30%	0.02%	1.32%	1.31%	0.02%	1.34%
322.00 Reactor Plant Equipment	1.22%	0.06%	1.28%	0.98%	0.42%	1.40%
323.00 Turbogenerator Units	2.15%	0.04%	2.19%	2.31%	0.24%	2.54%
324.00 Accessory Electric Equipment	1.21%	0.01%	1.22%	1.08%	0.01%	1.09%
325.00 Miscellaneous Power Plant Equipment	1.64%	0.06%	1.70%	1.94%	0.06%	2.00%
Total Palo Verde Common	1.40%	0.04%	1.44%	1.46%	0.08%	1.54%
OTHER PRODUCTION (by Unit)						
Douglas CT						
341.00 Structures and Improvements	5.13%	-0.26%	4.87%	16.13%	0.81%	16.94%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.01%	0.89%	24.09%	1.08%	25.17%
343.00 Prime Movers	-0.25%	0.02%	-0.23%	11.37%	-9.17%	2.20%
344.00 Generators and Devices	-0.28%	0.01%	-0.27%	18.97%	0.95%	19.92%
345.00 Accessory Electric Equipment	0.02%	0.02%	0.04%	23.54%	1.09%	24.63%
346.00 Miscellaneous Power Plant Equipment	0.70%	-0.03%	0.67%	24.08%	1.28%	25.36%
Total Douglas CT	-0.10%	0.01%	-0.09%	14.16%	-6.05%	8.11%
Ocotillo CT Units 1-2						
341.00 Structures and Improvements	4.19%	-0.20%	3.99%	5.50%	0.48%	5.98%
342.00 Fuel Holders, Products and Accessories	2.07%	-0.10%	1.97%	3.72%	0.19%	3.91%
343.00 Prime Movers	0.73%	-0.03%	0.70%	5.41%	0.70%	6.11%
344.00 Generators and Devices	3.44%	-0.61%	2.83%	4.73%	0.25%	4.98%
345.00 Accessory Electric Equipment	1.60%	-0.06%	1.54%	4.84%	0.27%	5.11%
346.00 Miscellaneous Power Plant Equipment	2.14%	-0.09%	2.05%	4.18%	0.20%	4.38%
Total Octillo CT Units 1-2	1.91%	-0.23%	1.68%	5.07%	0.48%	5.55%
Redhawk CC Units 1-2						
341.00 Structures and Improvements	3.13%	-0.12%	3.01%	4.00%	0.20%	4.20%
342.00 Fuel Holders, Products and Accessories	3.63%	-0.18%	3.45%	4.37%	0.23%	4.60%
343.00 Prime Movers	3.11%	-0.08%	3.03%	3.97%	0.26%	4.23%
344.00 Generators and Devices	3.33%	-0.83%	2.50%	4.33%	-0.11%	4.22%
345.00 Accessory Electric Equipment	3.11%	-0.10%	3.01%	3.97%	0.19%	4.16%
346.00 Miscellaneous Power Plant Equipment	3.60%	-0.18%	3.42%	4.41%	0.20%	4.61%
Total Redhawk CC Units 1-2	3.27%	-0.56%	2.71%	4.21%	0.02%	4.23%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
Account Description	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Saguaro						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.71%	-0.03%	0.68%	4.09%	0.47%	4.56%
344.00 Generators and Devices	2.92%	-0.19%	2.73%	2.97%	0.15%	3.12%
345.00 Accessory Electric Equipment	0.55%	-0.01%	0.54%	4.08%	0.25%	4.33%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro	2.16%	-0.13%	2.03%	3.40%	0.27%	3.67%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.45%	-0.02%	0.43%	4.10%	0.50%	4.60%
344.00 Generators and Devices	3.36%	-0.52%	2.84%	2.72%	0.15%	2.87%
345.00 Accessory Electric Equipment	0.46%	-0.01%	0.45%	4.12%	0.25%	4.37%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro CT Units 1-2	1.46%	-0.12%	1.34%	3.73%	0.38%	4.11%
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.85%	-0.14%	2.71%	3.99%	0.20%	4.19%
344.00 Generators and Devices	2.85%	-0.14%	2.71%	3.01%	0.15%	3.16%
345.00 Accessory Electric Equipment	2.85%	-0.14%	2.71%	3.00%	0.16%	3.16%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	2.85%	-0.14%	2.71%	3.07%	0.16%	3.23%
Solar Units						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total Solar Units	3.36%	-0.01%	3.35%	3.58%	0.28%	3.86%
Chino Valley						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.26%	3.79%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.53%	0.26%	3.79%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
Total Chino Valley	3.33%		3.33%	3.53%	0.26%	3.79%
Cotton Center						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.24%	3.76%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.24%	3.76%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
Total Cotton Center	3.33%		3.33%	3.52%	0.24%	3.76%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Net Salvage	Total	Proposed (at 12/31/2015) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Desert Star						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.52%	5.03%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.52%	5.03%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
Total Desert Star	3.33%		3.33%	4.51%	0.52%	5.03%
Foothills Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.48%	0.30%	3.78%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.48%	0.30%	3.78%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
Total Foothills Units 1-2	3.33%		3.33%	3.48%	0.30%	3.78%
Gila Bend						
341.05 Structures and Improvements	3.33%		3.33%	3.46%	0.36%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.46%	0.36%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
Total Gila Bend	3.33%		3.33%	3.46%	0.36%	3.82%
Hyder Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.51%	0.16%	3.67%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.50%	0.16%	3.66%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.16%	3.64%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.42%	0.15%	3.57%
Total Hyder Units 1-2	3.33%		3.33%	3.50%	0.16%	3.66%
Legacy Units						
341.00 Structures and Improvements	-3.55%	0.20%	-3.35%	1.31%	0.03%	1.34%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	3.93%	-0.86%	3.07%	3.44%	0.08%	3.52%
345.00 Accessory Electric Equipment	7.41%	-0.37%	7.04%	4.23%	0.22%	4.45%
346.00 Miscellaneous Power Plant Equipment						
Total Legacy Units	4.65%	-0.71%	3.94%	3.59%	0.12%	3.71%
Luke AFB						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.54%	5.05%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.54%	5.05%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
Total Luke AFB	3.33%		3.33%	4.51%	0.54%	5.05%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015) Investment	Current Net Salvage	Current Total	Proposed (at 12/31/2015) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
Roof Tops						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.18%	3.71%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.55%	0.18%	3.73%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.54%	0.18%	3.72%
346.05 Miscellaneous Power Plant Equipment						
Total Roof Tops	3.33%		3.33%	3.55%	0.18%	3.73%
Paloma						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.30%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.30%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
Total Paloma	3.33%		3.33%	3.52%	0.30%	3.82%
Sundance						
341.00 Structures and Improvements	2.06%	-0.10%	1.96%	2.49%	0.23%	2.72%
342.00 Fuel Holders, Products and Accessories	2.05%	-0.10%	1.95%	2.45%	0.12%	2.57%
343.00 Prime Movers	2.04%	-0.11%	1.93%	2.34%	0.12%	2.46%
344.00 Generators and Devices	2.51%	-0.13%	2.38%	4.45%	0.22%	4.67%
345.00 Accessory Electric Equipment	2.05%	-0.10%	1.95%	2.41%	0.13%	2.54%
346.00 Miscellaneous Power Plant Equipment	2.49%	-0.12%	2.37%	2.85%	0.15%	3.00%
Total Sun Dance	2.06%	-0.11%	1.95%	2.44%	0.13%	2.57%
West Phoenix						
341.00 Structures and Improvements	3.04%	-0.15%	2.89%	3.39%	0.23%	3.62%
342.00 Fuel Holders, Products and Accessories	3.67%	-0.17%	3.50%	3.81%	0.19%	4.00%
343.00 Prime Movers	2.73%	-0.09%	2.64%	3.64%	0.19%	3.83%
344.00 Generators and Devices	3.33%	-0.36%	2.97%	3.88%	0.03%	3.91%
345.00 Accessory Electric Equipment	3.51%	-0.15%	3.36%	4.53%	0.29%	4.82%
346.00 Miscellaneous Power Plant Equipment	3.80%	-0.17%	3.63%	4.45%	0.23%	4.68%
Total West Phoenix	3.18%	-0.24%	2.94%	3.84%	0.11%	3.95%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	5.00%	-0.24%	4.76%	4.03%	0.19%	4.22%
342.00 Fuel Holders, Products and Accessories	4.02%	-0.18%	3.84%	3.94%	0.20%	4.14%
343.00 Prime Movers						
344.00 Generators and Devices	4.08%	-0.65%	3.43%	4.00%	0.14%	4.14%
345.00 Accessory Electric Equipment	4.01%	-0.15%	3.86%	5.21%	0.35%	5.56%
346.00 Miscellaneous Power Plant Equipment	4.17%	-0.18%	3.99%	4.82%	0.23%	5.05%
Total West Phoenix CC Units 1-3	4.07%	-0.48%	3.59%	4.21%	0.19%	4.40%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	3.05%	-0.15%	2.90%	3.30%	0.17%	3.47%
342.00 Fuel Holders, Products and Accessories	2.98%	-0.15%	2.83%	3.21%	0.16%	3.37%
343.00 Prime Movers	2.98%	-0.15%	2.83%	3.21%	0.02%	3.23%
344.00 Generators and Devices	3.07%	-0.30%	2.77%	3.80%	0.18%	3.98%
345.00 Accessory Electric Equipment	3.57%	-0.18%	3.39%	4.00%	0.20%	4.20%
346.00 Miscellaneous Power Plant Equipment	3.72%	-0.17%	3.55%	4.50%	0.22%	4.72%
Total West Phoenix CC Unit 4	3.02%	-0.19%	2.83%	3.40%	0.08%	3.48%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
West Phoenix CC Unit 5						
341.00 Structures and Improvements	2.92%	-0.15%	2.77%	3.48%	0.18%	3.66%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	3.01%	-0.08%	2.93%	3.53%	0.20%	3.73%
344.00 Generators and Devices	2.97%	-0.19%	2.78%	3.76%	-0.09%	3.67%
345.00 Accessory Electric Equipment	2.91%	-0.15%	2.76%	3.52%	0.19%	3.71%
346.00 Miscellaneous Power Plant Equipment	3.40%	-0.17%	3.23%	4.12%	0.22%	4.34%
Total West Phoenix CC Unit 5	2.98%	-0.15%	2.83%	3.67%	0.03%	3.70%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	3.80%	-0.19%	3.61%	6.05%	0.46%	6.51%
342.00 Fuel Holders, Products and Accessories	0.61%	-0.03%	0.58%	3.36%	0.17%	3.53%
343.00 Prime Movers	1.00%	-0.03%	0.97%	5.03%	0.49%	5.52%
344.00 Generators and Devices	2.25%	-0.21%	2.04%	4.80%	0.29%	5.09%
345.00 Accessory Electric Equipment	0.95%	-0.04%	0.91%	2.61%	0.13%	2.74%
346.00 Miscellaneous Power Plant Equipment	3.25%	-0.16%	3.09%	3.52%	0.26%	3.78%
Total West Phoenix CT Units 1-2	1.62%	-0.10%	1.52%	4.86%	0.40%	5.26%
West Phoenix Common						
341.00 Structures and Improvements	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total West Phoenix Common	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
Yucca						
341.00 Structures and Improvements	2.41%	-0.09%	2.32%	4.70%	0.29%	4.99%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.04%	0.86%	1.86%	0.10%	1.96%
343.00 Prime Movers	2.54%	-0.13%	2.41%	2.98%	0.19%	3.17%
344.00 Generators and Devices	1.29%	-0.24%	1.05%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	1.15%	-0.05%	1.10%	2.94%	0.27%	3.21%
346.00 Miscellaneous Power Plant Equipment	1.82%	-0.09%	1.73%	2.88%	0.15%	3.03%
Total Yucca	2.26%	-0.13%	2.13%	3.06%	0.19%	3.25%
Yucca CT Units 1-4						
341.00 Structures and Improvements	2.29%	-0.08%	2.21%	4.99%	0.31%	5.30%
342.00 Fuel Holders, Products and Accessories	0.11%		0.11%	1.42%	0.08%	1.50%
343.00 Prime Movers	-0.09%		-0.09%	2.80%	0.44%	3.24%
344.00 Generators and Devices	1.27%	-0.24%	1.03%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	0.75%	-0.03%	0.72%	2.84%	0.27%	3.11%
346.00 Miscellaneous Power Plant Equipment	1.11%	-0.06%	1.05%	2.38%	0.12%	2.50%
Total Yucca CT Units 1-4	0.80%	-0.09%	0.71%	3.12%	0.28%	3.40%
Yucca CT Units 5-6						
341.00 Structures and Improvements	2.97%	-0.15%	2.82%	3.29%	0.17%	3.46%
342.00 Fuel Holders, Products and Accessories	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
343.00 Prime Movers	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
344.00 Generators and Devices	2.97%	-0.15%	2.82%	3.14%	0.16%	3.30%
345.00 Accessory Electric Equipment	2.97%	-0.15%	2.82%	3.41%	0.23%	3.64%
346.00 Miscellaneous Power Plant Equipment	2.97%	-0.15%	2.82%	3.70%	0.19%	3.89%
Total Yucca CT Units 5-6	2.97%	-0.15%	2.82%	3.03%	0.15%	3.18%

Appendix B

Palo Verde Decommissioning Trust Amounts
Test Year Ended 12/31/2015
(Dollars in Thousands)

YEAR	6/1/2045 UNIT 1	4/24/2046 UNIT 2	11/25/2047 UNIT 3	TOTAL[2]	ACC Jurisdictional Amount[1]
2016	449	-	1,832	2,281	$ 2,265
2017	377	868	1,036	2,281	2,265
2018	377	868	1,036	2,281	2,265
2019	377	868	1,036	2,281	2,265
2020	377	868	1,036	2,281	2,265
2021	377	868	1,036	2,281	2,265
2022	377	868	1,036	2,281	2,265
2023	377	868	1,036	2,281	2,265
2024	377	868	1,036	2,281	2,265
2025	377	868	1,036	2,281	2,265
2026	377	868	1,036	2,281	2,265
2027	377	868	1,036	2,281	2,265
2028	377	868	1,036	2,281	2,265
2029	377	868	1,036	2,281	2,265
2030	377	868	1,036	2,281	2,265
2031	377	868	1,036	2,281	2,265
2032	377	868	1,036	2,281	2,265
2033	377	868	1,036	2,281	2,265
2034	377	868	1,036	2,281	2,265
2035	377	868	1,036	2,281	2,265
2036	377	868	1,036	2,281	2,265
2037	377	868	1,036	2,281	2,265
2038	377	868	1,036	2,281	2,265
2039	377	868	1,036	2,281	2,265
2040	377	868	1,036	2,281	2,265
2041	377	868	1,036	2,281	2,265
2042	377	868	1,036	2,281	2,265
2043	377	868	1,036	2,281	2,265
2044	377	868	1,036	2,281	2,265
2045	189	868	1,036	2,092	2,078
2046	-	217	1,036	1,253	1,244
2047	-	-	1,036	1,036	1,028
	$ 11,207	$ 25,389	$ 33,933	$ 70,528	$ 70,049

1. ACC Jurisdictional share is approximately 99.32%.
2. Arizona Public Service Company ("APS") is proposing to keep the level of Decommissioning Trust funding constant. Therefore, APS is not proposing any additional funding even though APS anticipates higher amounts than what are reflected in this Schedule.

Appendix C

aps

Power Supply Adjustment
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company (APS) by the Commission on June 28, 2007 in Decision No. 69663, and subsequently amended by the Commission in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), and XXXXX (XXX XX, 201X). The PSA provides for the recovery of fuel and purchased power costs and other production-related variable costs to the extent that those costs deviate from the amount recovered through APS's Base PSA Cost ($0.030667 per kWh) authorized in Decision No. XXXXX, from XXX XX, 201X.

Non-fuel production costs included in the PSA relate to environmental chemical expenses which vary directly with power plant production. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The PSA allows for the refund or recovery of said costs that deviate from the base cost amount of $0.000500 per kWh[1].

In addition, the PSA allows for the refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base cost amount of ($0.000001) per kWh[2] and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.

APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur California's carbon emission allowance costs when doing so is not an economical choice for APS's Arizona ratepayers.

[1] $0.000500 per kWh is the result of the following: (2015 chemical costs of $13,527,111 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

[2]($0.000001) per kWh is the result of the following: (2015 net gains from sales of SO_2 allowances of $25,181 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and environmental chemical costs for fossil fuel production, and margins on the sales of emission allowances ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year absent express approval of the Commission. This PSA also provides a mechanism for mid-year rate adjustment by either the Commission or the Company (only if overcollection) in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year's[3] PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual PSA Costs (fuel, purchased power and other allowable costs) and the recovery of those same cost elements through the combination of base rates and the Forward Component, and which provides for their recovery or refund during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek mid-year changes in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power and other allowable costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery/refund, should the Commission deem such an adjustment to be appropriate or if the Company requests to make such refund of an overcollection.
    b. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before November 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February

[3] Each February 1 through January 31 period shall constitute a PSA Year

1 and ends on the ensuing January 31. APS will submit, on or before November 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS's over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e. February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual November 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the current PSA Year). The APS filing shall use these balances to calculate the Historical Component for the coming PSA Year[4].

The November 30 filing's use of estimated balances for November through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1.

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component

[4] For example, the November 30, 2008 filing would include actual balances for February through October of 2008 and estimated balances for November 2008 through January 2009.

Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any approved mid-year changes to the PSA rate. APS or Staff may request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component. The Commission on its own motion may also change the PSA rate as described above.

Notwithstanding the preceding paragraph, APS may at any time during the PSA Year request to reduce the PSA through the Transition Component, which request shall be deemed approved and become effective beginning with the first billing cycle of the month following the filing of such a request, provided APS files the request within the first 15 days of a month and Staff does not file opposition to the request.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before November 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.,* Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate shall go into effect. However, the PSA rate may not change from the prior year's PSA rate by more than plus or minus $0.004 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA rate shall be applicable to APS's retail electric rate schedules (with the exception of E-36 XL, AG-X, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. November 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before November 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

b. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

c. Review Process

The Commission Staff and interested parties shall have an opportunity to review the November 30 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the November 30 calculations shall be filed within 60 days of the APS filing. Before Storage Product Costs may be calculated in the PSA, APS will first seek approval. APS will request this approval by filing the third party storage contract with the Commission at least 90 days before the contract becomes effective. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.

5. Verification and Audit

[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power and other allowable costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest - Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA year will be credited an amount equal to interest at a rate equal to the Company's authorized Return on Equity ("ROE") or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Base Chemical Costs - An amount generally expressed as a rate per kWh, which reflects the non-fuel production costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The Base Chemical Costs are set at $0.000500 per kWh effective on XXX XX, 201X.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.030168 per kWh effective on XXX XX, 201X.

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on XXX XX, 201X.

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power as defined above, the Base Chemical Costs, and the Base Net Margins on the Sale of Emission Allowances.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS's base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS's over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue, plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest at year end. The balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mandated Carbon Emission Allowance Costs – The costs incurred in purchasing allowances to meet legal requirements, beginning in 2013, that electricity from resources which emit carbon must be accompanied by carbon emission allowances equal to the amount of carbon emitted in generating the electricity (recorded in FERC Account 509 – Allowances).

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load refers to the energy for both customer load in the balancing authority area for which APS has a generation service obligation plus PacifiCorp Supplemental Sales.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

PacifiCorp Supplemental Sales - The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990 which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

PSA - The Power Supply Adjustment mechanism approved by the Commission.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus costs for environmental chemicals used in power production at fossil and nuclear production sites, approved storage product costs, and the Net Margins on the Sales of Emission Allowances.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Rate Schedule AG-X -Alternative Generation Rate Schedule approved by the Commission in Decision No. XXXXX. Resale of capacity and energy displaced by Rate Schedule AG-X shall be excluded from the PSA at a flat amount of $1,250,000 a month. The portion of capacity and energy sales margins that is not the result of displacement from Rate Schedule AG-X will continue to be a credit to the PSA.

Storage Product Costs - All costs associated with third-party storage facilities, including rent, capacity, and lease payments for electricity storage facilities (e.g. batteries) that APS utilizes in the dispatch of generated or purchased electricity.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36 XL, AG-X, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. xxxxx.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS's electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration

Schedule 1	Power Supply Adjustment (PSA) Rate Calculation
Schedule 2	PSA Forward Component Rate Calculation
Schedule 3	PSA Year Forward Component Tracking Account
Schedule 4	PSA Historical Component Rate Calculation
Schedule 5	Historical Component Tracking Account
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account

8. Compliance Reports

APS shall provide monthly reports to Staff and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in APS's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Margins on the sale of excess emission allowances.
    c. Environmental chemical costs for fossil generation.
    d. Customer sales in both MWh and thousands of dollars by customer class.
    e. Number of customers by customer class.
    f. A detailed listing of all items excluded from the PSA calculations.
    g. A detailed listing of any adjustments to the adjustor reports.
    h. Total off-system sales revenues.
    i. System losses in MW and MWh.
    j. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage factor, both monthly and 12-month average.

4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.
3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm or per MCF, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. A summary of the net margins on the sale of emission allowances.
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, costs for specified environmental chemicals that vary with power generated at fossil power plants, storage product costs, and the net margins on the sale of emission allowances and Mandated Carbon Emission Allowance Costs will also be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission (FERC) accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- 509 Allowances[6]

Additionally, broker fees recorded in FERC account 557 up to the amount included in the Base Fuel Cost, costs for environmental chemicals used in power production in FERC accounts 502 and 549, and the FERC account where applicable Storage Product Costs will be recorded are allowable accounts.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 XL and AG-X customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs and kWh usage are excluded from the PSA.

[6] Or any successor FERC account used to record the costs of purchasing carbon emission allowances.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation
($/kWh)

Line No.	PSA Rate Calculation	Current February 1, XXXX	Proposed February 1, XXXX [1]	Increase/(Decrease) $/kWh	Increase/(Decrease) %
1	Forward Component Rate - FC (Schedule 2, L16)	$ -	$ -	N/A	N/A
2	Historical Component Rate - HC (Schedule 4, L5) [2]	#.######	$ -	N/A	N/A
3	PSA Transition Component Rate (Schedule 6, L3) [3]	$ -	$ -	N/A	N/A
4	**PSA Rate (L1+ L2 + L3)**	#.######	$ -	N/A	N/A

Notes:
[1] Proposed levels of the PSA rate components are provided in the November 30 filing each year.
[2] A Historical Component is a true up related to respective prior period PSA activity.
[3] Provides for Mid-Period Corrections when necessary.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
PSA Forward Component Rate Calculation
($ in thousands; Forward Component Rate in $/kWh)

Line No.	PSA Forward Component Rate - Calculation	Current February 1, XXXX	Proposed February 1, XXXX [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Projected Fuel and Purchased Power Costs	$ #,###,###	$ -	N/A	N/A
2	Projected Off-System Sales Revenue	$ #,###,###	-	N/A	N/A
3	PSA Adjustments to Fuel and Purchased Power Costs [2]	$ (#,###,###)	-	N/A	N/A
4	Net Fuel and Purchased Power Cost (L1 through L3)	$ #,###,###	$ -	N/A	N/A
5	Projected Fossil Chemical Costs	-	-	N/A	N/A
6	Projected Net Margins on the Sale of Emission Allowances	-	-	N/A	N/A
7	Projected Billed Native Load Sales, excluding E-36XL and AG-X (MWh) [3]	##,###,###	-	N/A	N/A
8	Projected Average Net Fuel Cost $/kWh (L4 / L7)	#.######	$ -	N/A	N/A
9	Average Fossil Chemical Costs $/kWh (L5 / L7)	#.######	-	N/A	N/A
10	Projected Average Margin on Emission Allowances $/kWh (L6 / L7)	$ -	$ -	N/A	N/A
11	Total Projected Average PSA Cost $/kWh (L8+L9+L10)	#.######	$ -	N/A	N/A
12	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh [4]	$ #.######	$ -	N/A	N/A
13	Authorized Base Chemical Cost Rate $/kWh [4]	#.######	-	N/A	N/A
14	Authorized Base Net Margins on the Sale of Emission Allowances Rate $/kWh [4]	$ #.######	$ -	N/A	N/A
15	Total Authorized Base Cost $/kWh	#.######	$ -	N/A	N/A
16	Forward Component Rate $/kWh (L11 - L15)	#.######	$ -	N/A	N/A

Notes:

[1] Proposed levels are provided in the November 30 filing each year.

[2] Includes costs associated with E-36XL, AG-X and other direct assignment customers, ISFSI, and mark-to-market accounting adjustments.

[3] The Projected Billed Native Load Sales of X,XXX,XXX MWh for the Current Rate represent forecast sales for XXXX as of November 30th, XXXX. They exclude sales made under the City of Williams wholesale contract through December 2017.

[4] Base Cost of Fuel and Purchased Power, Chemicals, and Net Margins on the Sale of Emission Allowances established in Decision No. XXXXX.

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kW

DOCKET NO. E-01345A-16-0036 ET AL.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
XXXX PSA Year Forward Component Tracking Account - in Effect from February 1, XXXX to Jan 31, XXXX
($ in thousands; Forward Component Rate and Base Rate in $/kWh)

			Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sept-XX	Oct-XX	Nov-XX	Dec-XX	Jan-XX	XXXX Total
1	Prior Month's Balance	From L27													
	Energy Sales														
2	PSA Retail Energy Sales [1]														
3	Wholesale Native Load Energy Sales [2]														
4	Total Native Load Energy Sales	L2 + L3	-	-	-	-	-	-	-	-	-	-	-	-	
5	Retail Energy Sales as a % of Total	L2 / L4													
6	Retail Billed Sales Excluding E-36XL and AG-X Sales (MWh) [3]														
	PSA Costs														
7	Fuel and Purchased Power Costs [4,5]														
8	Off System Revenue (Credit) [6]														
9	Off System Margin Displaced by AG-X (Debit)														
10	Fossil Chemical Costs														
11	Net Margins on Sale of Emission Allowances														
12	Net PSA Costs	sum(L7 to L11)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Retail PSA Costs														
13	Fuel and Purchased Power Costs	L5 * L7													
14	Off System Revenue (Credit)	L5 * L8													
15	Off System Margin Displaced by AG-X (Debit)	L5 * L9													
16	Fossil Chemical Costs	L5 * L10													
17	Net Margins on Sale of Emission Allowances	L5 * L11													
18	Net Retail PSA Costs	sum(L13 to L17)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	Base Rate Power Supply Recovery														
19	Fuel and Purchased Power Recovery	L29 * L2													
20	Fossil Chemical Cost Recovery	L30 * L2													
21	Net Margins on Sale of Emission Allowances Recovery	L31 * L2													
	(Over) Under Recovery From Base Rate														
22	Fuel and Purchased Power (Over) Under Recovery	(L13 + L14 + L15) - L19													
23	Fossil Chemical Costs (Over) Under Recovery	L16 - L20													
24	Net Margins on Sale of Emission Allowances (Over) Under Recovery	L17 - L21													
25	Total (Over) Under Recovery	sum(L22 to L24)	-	-	-	-	-	-	-	-	-	-	-	-	
26	Forward Component Collections [7]	- L32 * L6													
27	Tracking Account Balance	L1 + L25 + L26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
28	Annual Interest (Calculated only in January)													$ -	

29	Total Base Fuel Rate - ¢ per kWh	#.####
30	Base Chemical Rate - ¢ per kWh	#.####
31	Base Net Margin on the Sale of Emission Allowances - ¢ per kWh	#.####
32	Forward Component Rate - ¢ per kWh	#.####

Notes:

[1] PSA Retail Energy Sales are the calendar month's MWh sales. XXXX PSA Year Cumulative Retail Energy Sales of XX,XXX MWhs under rate schedules E-36XL and AG-X are excluded from the PSA Calculations.

[2] Includes traditional sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. City of Williams energy sales through December 2017 are excluded from the PSA Calculation.

[3] Retail Billed Sales on Line 6 relate specifically to the Forward Component Collections. Due to billing adjustments and timing, this amount may differ from other components' Retail Billed Sales.

[4] Renewables costs exclude $X,XXX,XXX of XXXX PSA Year year-to-date costs that are currently being recovered through the REAC rate schedule.

[5] Includes native load and off-system fuel and purchased power costs less those costs associated with E-36XL, AG-X and other direct assignment customers, amortization of previously deferred ISFSI, coal reclamation, and mark-to-market accounting adjustments.

[6] Includes off-system revenue less mark-to-market accounting adjustments.

[7] Generally, Line 32 * Line 6 = Line 26; however, differences may occur due to billing adjustments.

DECISION NO. 76295

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historical Component Rate Calculation
($ in thousands; Historical Component Rate in $/kWh)

Line No.	PSA Historical Component Rate Calculation	Current February 1, XXXX	Proposed February 1, XXXX [1]	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	Forward Component Tracking Account Balance (Schedule 3, L27 + L28)	#,###	$ -	N/A	N/A
2	Historical Component Tracking Account Balance (Schedule 5, L9 + L10) [2]	#,###	-	N/A	N/A
3	Total Historical Amount to be (Refunded)/Collected Balance (L1+L2)	#,###	$ -	N/A	N/A
4	Projected Billed Retail Energy Sales without E-36 XL and AG-X (MWh)	##,###,###	-	N/A	N/A
5	Applicable Historical Component Rate (L3 / L4)	#.######	$ -	N/A	N/A

Notes:
[1] Proposed levels are provided in the November 30 filing each year.
[2] The Current Rate Projected Billed Retail Energy Sales are for February XXXX through January XXXX.

Schedule presentation will appear to round up to $000s; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
Historical Component Tracking Account in Effect Feb 1, XXXX through Jan. 31, XXXX
($ in thousands Historical Component Rate in $/kWh)

Line No.		January	February	March	April	May	June	XXXX Data July	August	September	October	November	December	XXXX January
1	Projected HC Tracking Account Balance at Nov. 30, XXXX													
2	Projected FC Tracking Account Balance at Nov. 30, XXXX													
3	True-up from November - January Estimate [1]													
4	Prior Month's Ending Balance													
5	HC Adjusted Beginning Balance (L1+ L2 + L3 + L4)													
6	Applicable Historical Component Rate ($/kWh) [2]													
7	Retail Billed Sales Excluding E-36XL and AG-X Sales (MWhs) [3]													
8	Less Revenue from Applicable HC (L6 x L7) [4]													
9	HC Ending Balance (L5 - L8)	$ -												
10	Annual Interest (Calculated only in January)													

Notes:
[1] True-up is the result of using estimated revenue and deferral for November, December and January since the actual amount was not available at the time of the projected PSA rate filing.
[2] Historical Component, Schedule 4, Line 5
[3] Sales amounts are for energy billed each period.
[4] Generally, Line 7 x Line 6 = Line 8; however, differences may occur due to billing adjustments.

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 6
PSA Transition Component Rate Calculation
($ in thousands; Transition Component Rate(s) in $/kWh)

Line No.		Current February 1, XXXX	Proposed February 1, XXXX	Increase/(Decrease) $ Values	Increase/(Decrease) %
1	PSA Transition - Approved (Refundable)/Collection Amount [1]	N/A	N/A	N/A	0.00%
2	Projected Energy Sales without E-36XL and AG-X (MWh) XXX. X, XX to XXX. X,XX	N/A	N/A	N/A	0.00%
3	PSA Transition Component (Refundable)/Collection Rate (L1 / L2)	N/A	N/A	N/A	0.00%

Notes:
[1] Commission Decision No. XXXXXXXXXX

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 7
PSA Transition Tracking Account in Effect XX 1, 20XX through XX 31, 20XX
($ in thousands; Transition Component Rate in $/kWh)

Line No.		January	February	March	April	May	June	20XX Data July	August	September	October	November	December	20XX January
1	Transferred balance from FC Tracking Acct Per Decision No. XXXXX			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Prior Month's Ending Balance			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Transition Component TA Adjusted Beginning Balance (L1+ L2)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable Transition TA Component Rate ($/kWh) [1]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Retail Billed Sales Excluding E-36XL and AG-X Sales (MWhs) [2]			-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable Transition Component (L4 x L5) [3]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Ending Balance; (L3 - L6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:
[1] Transition Component, Schedule 6, Line 3
[2] Sales amounts are for energy billed each period.
[3] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 8
Summary of Monthly Calculations
Mo YYYY
($ in thousands)

Line No.		XXXX Data January	February	March	April	May	June	July	August	September	October	November	December	XXXX January
	XXXX Forward Component Tracking Account													
1	Beginning Balance													
2	Transfers to XXXX Historical Component Tracking Account													
3	Transfers to XXXX Transition Component Tracking Account													
4	(Over)/Under Collection													
5	Less Revenue from Applicable Forward Component Rate													
6	Annual Interest (Calculated only in January)													
7	Ending Balance (Line 1 + Line 2 + Line 3 + Line 4 - Line 5 + Line 6)													
	XXXX Historical Component Tracking Account													
8	Beginning Balance													
9	Transfers from XXXX Forward Component Tracking Account													
10	Less Revenue from Applicable Historical Component Rate													
11	Annual Interest (Calculated only in January)													
12	Ending Balance (Line 8 + Line 9 - Line 10 + Line 11)													
	XXXX Transition Component Tracking Account													
13	Beginning Balance													
14	Transfers from XXXX Forward Component Tracking Account													
15	Less Revenue from Applicable Historical Component Rate													
16	Annual Interest (Calculated only in January)													
17	Ending Balance (Line 13 + Line 14 - Line 15 + Line 16)													
18	**Combined Balance ([Line 7 + Line 12 + Line 17])**[1]													
19	Annual Interest Rate	#.##%												

Schedule presentation will appear to round up to $000s and MWh; however, calculations are performed on an actual $ and kWh basis with resultant Rates/kWh rounded up to $0.000000/kWh.

[1] Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA Year will accrue interest at a rate equal to the Company's authorized ROE or APS's existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will accrue interest at a rate equal to the Company's authorized ROE or APS's existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 9
YYYY Native Load Customer Counts, Sales and Revenue
Mo YYYY

Line No.	Class	January	February	March	April	May	June	July	August	September	October	November	December	Total[1]
	Customers													
1	Residential													#DIV/0!
2	Commercial													#DIV/0!
3	Industrial													#DIV/0!
4	Irrigation													#DIV/0!
5	Sales for Resale[2]													#DIV/0!
6	Streetlights & Other Public Authority													#DIV/0!
7	Less E-36XL, AG-X and CoW (includes adj. to prior mth)													#DIV/0!
8	Total													#DIV/0!
	Sales (MWh)													
9	Residential													-
10	Commercial													-
11	Industrial													-
12	Irrigation													-
13	Sales for Resale[2]													-
14	Streetlights & Other Public Authority													-
15	Less E-36XL, AG-X and CoW (includes adj. to prior mth)													-
16	Total													-
	Revenue ($000)													
17														$ -
18	Commercial													$ -
19	Industrial													$ -
20	Irrigation													$ -
21	Sales for Resale[2]													$ -
22	Streetlights & Other Public Authority													$ -
23	Less E-36XL, AG-X and CoW (includes adj. to prior mth)													$ -
24	Total													$ -
	Est. System Losses and Peak													
25	Est. Native Load Sys. Losses (MWh)													
26	Est. Native Load Sys. Losses (MW)													
27	Est. Native Load Sys. Peak (MW)[3]													

[1] The Customers total is the average of the customer class' monthly totals.
[2] Includes traditional sales for resale, PacifiCorp supplemental sales, City of Williams (CoW), and other non-ACC jurisdictional sales. Off-System Interchange customers, sales and revenue are excluded from Sales for Resale.
[3] The Preliminary Native Load System Peak totals will be updated each month.

Appendix D

Transfer of Adjustors into Base Rates

$ in Millions

	$	%
Transmission Cost Adjustor Transfer	$ 128.785	4.46%
Lost Fixed Cost Recovery Adjustor Transfer	46.054	1.59%
Environmental Improvement Surcharge Transfer	2.459	0.09%
Demand Side Management Adjustment Clause Transfer	9.993	0.35%
Renewable Energy Adjustment Clause Transfer	37.596	1.30%
Four Corners Rate Rider Transfer	57.670	2.00%
System Benefits Charge Transfer	(14.604)	-0.51%
Total Surcharge Transfer	$ 267.953	9.28%

Appendix E

aps

PLAN OF ADMINISTRATION
TAX EXPENSE ADJUSTOR MECHANISM

Tax Expense Adjustor Mechanism
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Federal Income Tax Expense Adjustor Mechanism (TEAM) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on [insert date] in Decision No. XXXXX. In the event that significant Federal income tax reform legislation is enacted and effective prior to the conclusion of APS's next General Rate Case (GRC), and such legislation materially impacts [1] the Company's annual revenue requirements; the TEAM enables the pass-through of these income tax effects to customers. The TEAM will be calculated upon the effective date of legislation, and annually on a prospective basis, and will terminate upon the conclusion of APS's next GRC.

2. Definitions

Annual Tax Expense Adjustment – The Annual Tax Expense Adjustment represents the amount to be passed through to jurisdictional retail customers in the subsequent twelve month period and is applied to customer bills via a $ per kWh adjustment.

Base Revenue Requirements Change – The change in the Company's Base Revenue Requirements as a result of any Federal income tax reform legislation will be measured as the change in:

a. The Federal Income Tax Rate-Test Year as compared to the Federal Income Tax Rate-Revised as applied to the Company's Adjusted 2015 Test Year,
b. Annual amortization of any resulting excess deferred income tax regulatory account compared to the Company's Adjusted 2015 Test Year, and;
c. Permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted 2015 Test Year.

[1] "Material impacts" is defined as changing APS's revenue requirement by more than $5 million.

Federal Income Tax Rate-Revised – The Federal income tax rate that is revised as a result of any Federal income tax reform legislation enacted and effective subsequent to Decision No. XXXXX and prior to the conclusion of APS's next GRC.

Federal Income Tax Rate-Test Year – The Federal income tax rate of 35% in effect and utilized in the 2015 Test Year as approved by the Commission in Decision No. XXXXX.

Forecasted Retail kWh Sales – The forecasted calendar year energy (kWh) sales served under applicable ACC jurisdictional retail electric rate schedules. A true-up reconciliation of the forecasted data will be completed in the following year through the Balancing Account.

3. Calculation of TEAM

The Annual Tax Expense Adjustment is calculated annually and represents the amount to be passed through to jurisdictional retail customers. The adjustment is calculated based on the Company's Base Revenue Requirements Change resulting from any Federal income tax reform legislation enacted and effective subsequent to that used to set rates as approved in Decision No. XXXXX, and prior to the conclusion of APS's next GRC, as defined above.

The Annual Tax Expense Adjustment will be applied to applicable customers' total bill via a $ per kWh adjustment over the twelve month period beginning March 1 of the year following the rate filing described in Section 5 below. The TEAM $ per kWh rate is calculated by dividing the Annual Tax Expense Adjustment by the Forecasted Retail kWh Sales as determined in Schedule 1 of the filing.

4. TEAM Balancing Account

APS will maintain accounting records that accumulate the difference between the calculated Annual Tax Expense Adjustment as compared to the actual amounts applied to customers' total bills through the TEAM $ per kWh adjustment during the pass-through period (March through February). Additionally, as a result of utilizing Forecasted Retail kWh Sales, the balancing account will contain a true-up component in which estimated balances will be replaced with actual balances for the prior year filing.

The difference will be recorded to the TEAM Balancing Account each month and will accrue interest at the Company's applicable cost of short-term debt. In the event that the Annual Tax Expense Adjustment is more or less than the amount passed through to customers as of the last billing cycle of February, the over or under collection, plus interest, will be subtracted from or added to the TEAM calculation in the subsequent period.

5. Filing and Procedural Deadlines

APS will file the Annual Tax Expense Adjustment, including all Compliance Reports, with the Commission for the upcoming year by December 1st, terminating at the conclusion of APS's next GRC.

The Commission Staff and interested parties will have the opportunity to review the TEAM filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted or Staff has filed an objection by March 1st, the new TEAM $ per kWh rate proposed by APS will go into effect with the first billing cycle in March (without proration) and will remain in effect for the following 12-month period.

6. Compliance Reports

APS will provide an annual report to Staff and the Residential Utility Consumer Office detailing all calculations related to the TEAM $ per kWh adjustment. The reports will include the following Schedules 1 through 3 as attached to this document:

Schedule 1:	Current Year Annual Tax Expense Adjustment and TEAM $ per kWh Credit
Schedule 2:	Current Year TEAM Balancing Account
Schedule 3:	Adjusted 2015 Test Year SFR Schedules (as follows):

Schedule 3-A1:	Computation of Increase in Gross Revenue Requirements
Schedule 3-B1(1):	Summary of Original Cost Rate Base Elements
Schedule 3-B1(2):	Summary of RCND Rate Base Elements
Schedule 3-B2:	Original Cost Rate Base Pro Forma Adjustments
Schedule 3-B3:	RCND Rate Base Pro Forma Adjustments
Schedule 3-C1(1):	Total Company Adjusted Test Year Income Statement
Schedule 3-C1(2):	ACC Jurisdiction Adjusted Test Year Income Statement
Schedule 3-C2:	Income Statement Pro Forma Adjustments
Schedule 3-C3:	Computation of Gross Revenue Conversion Factor
Schedule 3-C2 Detail:	Detail of Pro Forma Adjustments as Shown on Schedule 3-C2

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1 - TEAM

ANNUAL TAX ADJUSTMENT AND TEAM $ PER KWH CREDIT FOR [YEAR]
CURRENT YEAR ENDED 12/31/XXXX
(Thousands of Dollars)

	(A)	(B)	(C)
Line No.	Annual Tax Adjustment and TEAM $ per kWh Credit for [Year]	Reference	$
1.	Annual Tax Adjustment for [Year]	Schedule 3, A-1, Line 10	
2.	Total TEAM Balancing Account	Schedule 2, Line 4	
3.	Total Annual Tax Adjustment for [Year]	Line 1 + Line 2	
4.	Forecasted Retail Sales (kWh)	Company Records	
5.	Annual TEAM $/kWh Credit	Line 3 / Line 4	

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2 - TEAM
TEAM BALANCING ACCOUNT
CURRENT YEAR ENDED 12/31/XXXX
(Thousands of Dollars)

	(A)	(B)	(C)
Line No.	Current Year TEAM Balancing Account	Reference	$
1.	Prior Period Annual Tax Adjustment	Previous Filing Schedule 1, Line 3	
2.	True-up from January-December Estimate (a)	Update Previous Filing	
3.	Amount Applied to Customer's Bills in Prior Period (b)	Company Records	
4.	TEAM Balancing Account	Line 1 + Line 2 - Line 3	

(a) Represents any difference between estimated prior period annual tax adjustment filed December 1, 20XX and actual annual tax adjustment based on final December 31, 20XX data.

(b) Represents the amount applied to customers for the twelve (12) calendar months of 20XX. True-up is the result of utilizing forecasted jurisdictional retail sales for the period January through December since the actual sales were not available at the time of prior period filing.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-A1 - TEAM
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2015
(Thousands of Dollars)

Line No.	Description	Electric Original Cost (A)	RCND (B)	Fair Value (C)	Line No.
1.	Adjusted Rate Base	[illegible]	[illegible]	[illegible]	1.
2.	Adjusted Operating Income	[illegible]	[illegible]	[illegible]	2.
3.	Current Rate of Return	[illegible]	[illegible]	[illegible]	3.
4.	Required Operating Income	[illegible]	[illegible]	[illegible]	4.
5.	Required Rate of Return on OCRB	[illegible]	[illegible]	[illegible]	5.
6.	Adjusted Operating Income Deficiency on OCRB	[illegible]	[illegible]	[illegible]	6.
7.	Gross Revenue Conversion Factor	[illegible]	[illegible]	[illegible]	7.
8.	Increse/(Decrease) in Base Revenue Requirements Based on OCRB	[illegible]	[illegible]	[illegible]	8.
9.	After Tax Return on Fair Value Increment			[illegible]	9.
10.	Requested Increse/(Decrease) in Base Revenue Requirements			[illegible]	10.

(A) Source: Schedule 3-B1 (1) (F)
(B) Source: Schedule 3-B1 (2) (F)
(C) Calculation

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B1 (1) - TEAM
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Settlement (A)	TEAM Pro Formas (B)	Adjusted Settlement (C)=(A)+(B)	Settlement (D)	TEAM Pro Formas (E)	Adjusted Settlement (F)=(D)+(E)	Line No.
1.	Gross utility plant in service							1.
2.	Less: Accumulated depreciation & amortization							2.
3.	Net utility plant in service							3.
	Deductions:							
4.	Deferred income taxes							4.
5.	Investment tax credits							5.
6.	Customer advances for construction							6.
7.	Customer deposits							7.
8.	Pension liabilities							8.
9.	Liability for asset retirements							9.
10.	Other deferred credits							10.
11.	Coal mine reclamation							11.
12.	Unrecognized tax benefits							12.
13.	Regulatory liabilities							13.
14.	Total deductions							14.
	Additions:							
15.	Regulatory assets							15.
16.	Other deferred debits							16.
17.	Decommissioning trust accounts							17.
18	OPEB assets							18
19.	Allowance for working capital							19.
20.	Total additions							20.
21.	Total rate base						(e)	21.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B1 (2) - TEAM
SUMMARY OF RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		RCND						
		Total Company			ACC			
Line No.	Description	Settlement (A)	TEAM Pro Formas (B)	Adjusted Settlement (C)=(A)+(B)	Settlement (D)	TEAM Pro Formas (E)	Adjusted Settlement (F)=(D)+(E)	Line No.
1.	Gross utility plant in service							1.
2.	Less: Accumulated depreciation & amortization							2.
3.	Net utility plant in service							3.
	Deductions:							
4.	Deferred income taxes							4.
5.	Investment tax credits							5.
6.	Customer advances for construction							6.
7.	Customer deposits							7.
8.	Pension liabilities							8.
9.	Liability for asset retirements							9.
10.	Other deferred credits							10.
11.	Coal mine reclamation							11.
12.	Unrecognized tax benefits							12.
13.	Regulatory liabilities							13.
14.	Total deductions							14.
	Additions:							
15.	Regulatory assets							15.
16.	Other deferred debits							16.
17.	Decommissioning trust accounts							17.
18	OPEB assets							18
19.	Allowance for working capital							19.
20.	Total additions							20.
21.	Total rate base						(e)	21.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B2 - TEAM
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

Line No.	Description	Settlement Test Year 12/31/2015 Total Co. (A)	Settlement Test Year 12/31/2015 ACC (B)	TEAM ADIT & Regulatory Account Impact Total Co. (C)	TEAM ADIT & Regulatory Account Impact ACC (D)	Adjusted Settlement at End of Test Year 12/31/2015 Total Co. (E)=(A)+(C)	Adjusted Settlement at End of Test Year 12/31/2015 ACC (F)=(B)+(D)
1.	Gross Utility Plant in Service						
2.	Less: Accumulated Depreciation & Amort.						
3	Net Utility Plant in Service						
4.	Less: Total Deductions						
5.	Total Additions						
6.	Total Rate Base						

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B3 - TEAM
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

		Settlement Test Year 12/31/2015		TEAM ADIT & Regulatory Account Impact		Adjusted Settlement at End of Test Year 12/31/2015	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
1.	Gross Utility Plant in Service						
2.	Less: Accumulated Depreciation & Amort.						
3	Net Utility Plant in Service						
4.	Less: Total Deductions						
5.	Total Additions						
6.	Total Rate Base						

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C1 (1) - TEAM
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		Total Company			
Line No.	Description	Settlement Test Year Ended 12/31/2015 (A)	TEAM Proforma Adjustments (B)	Settlement Results After Proforma Adjustments (C)=(A)+(B)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates	[illegible]	[illegible]	[illegible]	1.
2.	Revenues from Surcharges	[illegible]	[illegible]	[illegible]	2.
3.	Other Electric Revenues	[illegible]	[illegible]	[illegible]	3.
4.	Total	[illegible]	[illegible]	[illegible]	4.
	Operating expenses:				
5.	Electric fuel and purchased power	[illegible]	[illegible]	[illegible]	5.
6.	Operations and maintenance excluding fuel expenses	[illegible]	[illegible]	[illegible]	6.
7.	Depreciation and amortization	[illegible]	[illegible]	[illegible]	7.
8.	Income taxes	[illegible]	[illegible]	[illegible]	8.
9.	Other taxes	[illegible]	[illegible]	[illegible]	9.
10.	Total	[illegible]	[illegible]	[illegible]	10.
11.	Operating income	[illegible]	[illegible]	[illegible]	11.
	Other income (deductions):				
12.	Income taxes	[illegible]	[illegible]	[illegible]	12.
13.	Allowance for equity funds used during construction	[illegible]	[illegible]	[illegible]	13.
14.	Other income	[illegible]	[illegible]	[illegible]	14.
15.	Other expense	[illegible]	[illegible]	[illegible]	15.
16.	Total	[illegible]	[illegible]	[illegible]	16.
17.	Income before interest deductions	[illegible]	[illegible]	[illegible]	17.
	Interest deductions:				
18.	Interest on long-term debt	[illegible]	[illegible]	[illegible]	18.
19.	Interest on short-term borrowings	[illegible]	[illegible]	[illegible]	19.
20.	Debt discount, premium and expense	[illegible]	[illegible]	[illegible]	20.
21.	Allowance for borrowed funds used during construction	[illegible]	[illegible]	[illegible]	21.
22.	Total	[illegible]	[illegible]	[illegible]	22.
23.	Net income	[illegible]	[illegible]	[illegible]	23.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C1 (2) - TEAM
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		ACC Jurisdiction			
Line No.	Description	Settlement Test Year Ended 12/31/2015 (A)	TEAM Proforma Adjustments (B)	Settlement Results After Proforma Adjustments (C)=(A)+(B)	Line No.
	Electric Operating Revenues				
1.	Revenues from Base Rates				1.
2.	Revenues from Surcharges				2.
3.	Other Electric Revenues				3.
4.	Total				4.
	Operating expenses:				
5.	Electric fuel and purchased power				5.
6.	Operations and maintenance excluding fuel expenses				6.
7.	Depreciation and amortization				7.
8.	Income taxes				8.
9.	Other taxes				9.
10.	Total				10.
11.	Operating income				11.
	Other income (deductions):				
12.	Income taxes				12.
13.	Allowance for equity funds used during construction				13.
14.	Other income				14.
15.	Other expense				15.
16.	Total				16.
17.	Income before interest deductions				17.
	Interest deductions:				
18.	Interest on long-term debt				18.
19.	Interest on short-term borrowings				19.
20.	Debt discount, premium and expense				20.
21.	Allowance for borrowed funds used during construction				21.
22.	Total				22.
23.	Net income				23.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C2 - TEAM
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

		Normalize Income Tax Expense/Interest Synchronization		Interest Expense on Rate Base Impact		Total Income Tax Income Statement Adjustments	
Line No.	Description	Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
	Electric Operating Revenues						
1.	Revenues from Base Rates						
2.	Revenues from Surcharges						
3.	Other Electric Revenues						
4.	Total Electric Operating Revenues						
5.	Electric Fuel and Purchased Power Costs						
6.	Oper Rev Less Fuel & Purch Pwr Costs						
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense						
8.	Maintenance						
9.	Subtotal						
10.	Depreciation and Amortization						
11.	Amortization of Gain						
12.	Administrative and General						
13.	Other Taxes						
14.	Total Other Operating Expense						
15.	Operating Income Before Income Tax						
16.	Interest Expense						
17.	Taxable Income						
18.	Current Income Tax Rate -						
19.	Operating Income (line 15 minus line 18)						

(A) Source: Schedule 3-C2 Workpaper Detail

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY

Schedule 3-C3 - TEAM

COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

TEST YEAR ENDED 12/31/2015

		Settlement	TEAM Pro Forma	
Line No.	Description	Percentage of Incremental Gross Revenues (A)	Percentage of Incremental Gross Revenues (B)	*Line No.*
1	Gross Revenue			1
2	Less uncollectible revenue			2
3	Taxable revenue as a percent			3
4	Federal Income Taxes			4
5	State Income Taxes Net of Federal Tax Benefit			5
6	Total Tax Percentage			6
7	Taxable Revenue - Tax Percentage			7
8	1/Operating Income % = Gross Revenue Conversion Factor			8

'Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C2 Workpaper Detail - TEAM
TOTAL COMPANY
DETAIL OF PRO FORMA ADJUSTMENTS AS SHOWN ON SCHEDULE 3-C2
TEST YEAR ENDED 12/31/15
(Thousands of Dollars)

Line No.	Description	TEAM Pro Forma (A)	Settlement Test Year (B)
1.	**Pre-Tax Operating Income (SFR Schedule C-1, line 11 + line 8)**		
2.	**Allocated Interest Expense (unadjusted rate base SFR B-1 line 21 * cost of debt SFR D-1 line 1)**		
3.	**Adjusted Operating Income**		
4.	**Gross Income Tax at 38.10% (Settlement Test Year) and XX.XX% (TEAM Pro Forma)**		
5.	**Tax Effected Permanent Items**		
6.	Meals and Entertainment		
7.	Non-Deductible Compensation		
8.	Research & Development Credit		
9.	Amortization of OPEB Subsidy PPACA		
10.	Other Federal Tax Credits (Net)		
11.	Amortization of FAS109 Liability		
12.	Arizona Tax Credits		
13.	Depreciation on AFUDC		
14.	Amortization of Permanent Plant Basis Differences		
15a.	New Permanent Income Tax Adjustment [1]		
15b.	New Permanent Income Tax Adjustment [2]		
15c.	Other New Permanent Income Tax Adjustment (Add row as necessary)		
16.	Out of Period Adjustments		
	Rounding		
17.	**Net On-Going Tax Expense**	-	-
18.	**Settlement Test Year Tax Expense (SFR Schedule C-1, line 8)**	-	
19.	**TEAM Pro Forma Adjustment**	$ -	
(A)	Source: 2015 Test Year Normalize Income Tax Expense/Interest Synchronization pro forma, adjusted for tax reform impacts		

Appendix F

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RATE SCHEDULE R-XS
EXTRA SMALL RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to full requirements residential Customers with an average monthly energy usage of 600 kilowatt-hours (kWh) or less who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site. Annual reassignment will begin with January 2019 bills.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not have time-of-use charges, seasonal charges, or a demand charge.

CHARGES

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

Bundled Charges

Basic Service Charge	$0.329	per day
Energy Charge	$0.11672	per kWh

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

Customer Accounts Charge	$0.072	per day
Metering Charge	$0.104	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03112	per kWh
Generation Charge	$0.07187	per kWh

RATE SCHEDULE R-XS
EXTRA SMALL RESIDENTIAL SERVICE

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedules EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
8. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

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

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

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RATE SCHEDULE R-XS
EXTRA SMALL RESIDENTIAL SERVICE

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

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown below.

aps

RATE SCHEDULE R-BASIC
SMALL RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to residential Customers with an annual average monthly energy usage of more than 600 but less than 1,000 kilowatt-hours (kWh) who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site. Annual reassignment will begin with January 2019 bills.

Starting May 1, 2018, first-time Customers are not eligible for this rate for a period of ninety (90) days from the date service begins. After this initial 90-day period, qualifying Customers may move to this rate at any time but must remain on this R-Basic rate schedule for at least twelve (12) consecutive months before moving to another residential rate schedule for which the Customer may qualify.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not vary by time-of-use, season, or demand (how much energy is used at one time).

CHARGES

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

Bundled Charges

Basic Service Charge	$0.493	per day
Energy Charge	$0.12393	per kWh

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

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

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RATE SCHEDULE R-BASIC
SMALL RESIDENTIAL SERVICE

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03112	per kWh
Generation Charge	$0.07908	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

aps

**RATE SCHEDULE R-BASIC
SMALL RESIDENTIAL SERVICE**

SERVICE DETAILS

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

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

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

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

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RATE SCHEDULE R-BASIC L
LARGE RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to residential Customers with an annual average monthly energy usage of 1,000 kilowatt-hours (kWh) or more who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site.

Eligibility for this rate schedule will be frozen on May 1, 2018. After this date, Customers may not elect to take service under this rate, whether they are new or moving from a different rate. Charges on this schedule may change.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not vary by time-of-use, season, or demand (how much energy is used at one time).

CHARGES

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

Bundled Charges

Basic Service Charge	$0.658	per day
Energy Charge	$0.13412	per kWh

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

Customer Accounts Charge	$0.290	per day
Metering Charge	$0.215	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

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RATE SCHEDULE R-BASIC L
LARGE RESIDENTIAL SERVICE

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh
Delivery Charge	$0.03112	per kWh
Generation Charge	$0.08927	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

aps

RATE SCHEDULE R-BASIC L
LARGE RESIDENTIAL SERVICE

SERVICE DETAILS

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

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

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

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

aps

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday year round. This rate also has a Super Off-Peak period, which is 10 a.m. to 3 p.m. Monday through Friday during the winter billing cycles of November through April. All other hours are Off-Peak hours.

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

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

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

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

CHARGES

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

Bundled Charges

Basic Service Charge	$0.427	per day

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RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

Bundled Charges continued:

	Summer	Winter	
On-Peak Energy Charge	$0.24314	$0.23068	per kWh
Off-Peak Energy Charge	$0.10873	$0.10873	per kWh
Super Off-Peak Energy Charge		$0.03200	per kWh

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

Customer Accounts Charge	$0.073	per day
Metering Charge	$0.201	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Energy Charge Components

System Benefits Charge	$0.00276	per kWh
Transmission Charge	$0.01097	per kWh

	Summer	Winter	
Delivery Charge	$0.03112	$0.01105	per kWh
Generation On-Peak Charge	$0.19829	$0.18583	per kWh
Generation Off-Peak Charge	$0.06388	$0.06388	per kWh
Generation Super Off-Peak Charge		$0.00722	per kWh

CHARGE FOR ON-SITE DISTRIBUTED GENERATION CUSTOMERS

The monthly bill for Customers on this rate schedule who have an on-site distributed generation system will also include a Grid Access Charge. This charge will apply to the nameplate kW-dc power rating of the Customer's distributed generation facility:

Grid Access Charge	$0.93	per kW-dc of generation

aps

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

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

aps

RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE

SERVICE DETAILS

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

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

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

4. Direct Access Customers who purchase available electric servies from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Acounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing servies are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

aps

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will not vary by season.

TIME PERIODS

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

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

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

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

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

CHARGES

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

aps

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

Bundled Charges

Basic Service Charge:	$0.427	per day

	Summer	Winter	
On-Peak Demand Charge:	$8.40	$8.40	per kW
On-Peak Energy Charge:	$0.13160	$0.11017	per kWh
Off-Peak Energy Charge:	$0.07798	$0.07798	per kWh

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

Customer Accounts Charge:	$0.073	per day
Metering Charge	$0.201	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Demand Charge Components

Delivery On-Peak kW Charge	$4.000	per kW
Generation On-Peak kW Charge	$4.400	per kW

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Transmission Charge:	$0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$0.01105	$0.01105	per kWh
Generation On-Peak kWh Charge:	$0.10682	$0.08539	per kWh
Generation Off-Peak kWh Charge:	$0.05320	$0.05320	per kWh

aps

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

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

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to partial requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

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

aps

RATE SCHEDULE R-2
RESIDENTIAL SERVICE

SERVICE DETAILS

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

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

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

4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

5. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

   Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

aps

RATE SCHEDULE R-3
RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

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

TIME PERIODS

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

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

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

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

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

CHARGES

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

aps

RATE SCHEDULE R-3
RESIDENTIAL SERVICE

Bundled Charges

Basic Service Charge:	$0.427	per day

	Summer	Winter	
On-Peak Demand Charge:	$17.438	$12.239	per kW
On-Peak Energy Charge:	$0.08683	$0.06376	per kWh
Off-Peak Energy Charge:	$0.05230	$0.05230	per kWh

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

Customer Accounts Charge:	$0.073	per day
Metering Charge	$0.201	per day
Meter Reading Charge	$0.072	per day
Billing Charge	$0.081	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	$4.000	$4.000	per kW
Generation On-Peak kW Charge	$13.438	$8.239	per kW

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Transmission Charge:	$0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	$0.01105	$0.01105	per kWh
Generation On-Peak kWh Charge:	$0.06205	$0.03898	per kWh
Generation Off-Peak kWh Charge:	$0.02752	$0.02752	per kWh

aps

RATE SCHEDULE R-3
RESIDENTIAL SERVICE

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

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to partial requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Charge TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CCP- RES	Critical Peak Pricing (Residential)
EPR-2	Partial requirements
EPR-6	Partial Requirements - Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount

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RATE SCHEDULE R-3
RESIDENTIAL SERVICE

GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

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

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

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

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

5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.

6. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

   Monthly Load Factor = Billed kWh/(Billed kW * Billing Days * 24 hours)

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RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

AVAILABILITY

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

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

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

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

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

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

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

DESCRIPTION

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

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will also vary by season (summer or winter) and time of day (On-Peak or Off-Peak).

TIME PERIODS

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

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

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

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

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

CHARGES

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

Bundled Charges

Basic Service Charge	$0.493	per day

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

aps

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

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

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

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

Demand Charge Components

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

Energy Charge Components

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

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

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

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

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

ADJUSTMENTS

The bill will include the following adjustments:

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

RATE RIDERS

Eligible rate riders for this rate schedule are:

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

SERVICE DETAILS

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

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

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

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

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

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

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

Appendix G

Settlement Rate Summary for Residential Rates

	TOU-E	R-2	R-3
Bundled Rates			
Summer			
BSC $/day	0.427	0.427	0.427
On kW		8.400	17.438
On-peak kWh	0.24314	0.13160	0.08683
Off-peak kWh	0.10873	0.07798	0.05230
Winter			
BSC $/day	0.427	0.427	0.427
On kW		8.400	12.239
On-peak kWh	0.23068	0.11017	0.06376
Off-peak kWh	0.10873	0.07798	0.05230
Super Off-peak kWh	0.03200		
Unbundled Rates			
Generation - Summer			
kWh - on	0.19829	0.10682	0.06205
kWh - off	0.06388	0.05320	0.02752
kW - on		4.400	13.438
Generation - Winter			
kWh - on	0.18583	0.08539	0.03898
kWh - off	0.06388	0.05320	0.02752
kWh - super off	0.00722		
kW - on		4.400	8.239
Transmission - kWh	0.01097	0.01097	0.01097
Delivery - Summer			
kWh	0.03112	0.01105	0.01105
kW		4.000	4.000
Delivery - Winter			
kWh	0.01105	0.01105	0.01105
kW		4.000	4.000
System Benefits - kWh	0.00276	0.00276	0.00276
BSC $/day			
Customer accounts	0.073	0.073	0.073
Metering	0.201	0.201	0.201
Billing	0.081	0.081	0.081
Meter reading	0.072	0.072	0.072

	R-TECH
Bundled Rates	
Summer	
BSC $/day	0.493
On kW	20.250
Off kW	6.500
On-peak kWh	0.05750
Off-peak kWh	0.04750
Winter	
BSC $/day	0.493
On kW	14.250
Off kW	6.500
On-peak kWh	0.04750
Off-peak kWh	0.04750
Super Off-peak kWh	
Unbundled Rates	
Generation - Summer	
kWh - on	0.04167
kWh - off	0.03167
kW - on	13.750
kW - off	1.000
Generation - Winter	
kWh - on	0.03167
kWh - off	0.03167
kW - on	7.750
kW - off	1.000
Transmission - kWh	0.01097
Delivery	
kWh	0.00210
kW - on	6.500
kW - off	5.500
System Benefits - kWh	0.00276
BCS $-Day	
Customer accounts	0.125
Metering	0.215
Billing	0.081
Meter reading	0.072

Settlement Rate Summary for Residential Rates

	R-XS	R-BASIC	R-BASIC L
Bundled Rates			
Summer & Winter			
BSC $/day	0.329	0.493	0.658
kWh	0.11672	0.12393	0.13412
Unbundled Rates			
Generation kWh	0.07187	0.07908	0.08927
Transmission - kWh	0.01097	0.01097	0.01097
Delivery kWh	0.03112	0.03112	0.03112
System Benefits - kWh	0.00276	0.00276	0.00276
BSC $/day			
Customer accounts	0.072	0.125	0.290
Metering	0.104	0.215	0.215
Billing	0.081	0.081	0.081
Meter reading	0.072	0.072	0.072

Transition E-12	
Bundled Rates	
Summer	
BSC $/day	0.330
0-400 kWh	0.11161
401-800 kWh	0.15920
801-3000 kWh	0.18627
< 3000 kWh	0.19863
Winter	
BSC $/day	0.330
All kWh	0.10851
Unbundled Rates	
Generation - Summer	
1st 400 kWh	0.06676
Next 400 kWh	0.11435
Next 2200 kWh	0.14142
All other kWh	0.15378
Generation Winter - kWh	0.06366
Transmission - kWh	0.01097
Delivery kWh	0.03112
System Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.073
Metering	0.104
Billing	0.081
Meter reading	0.072

Settlement Rate Summary for Residential Rates

Transition TOU-E Bundled Rates	ET-1	ET-2
Summer		
BSC $/day	0.643	0.643
On-Peak kWh	0.20697	0.28205
Off-Peak kWh	0.06697	0.07105
Winter		
BSC $/day	0.643	0.643
On-Peak kWh	0.16794	0.22900
Off-Peak kWh	0.06397	0.07005
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.16211	0.23715
Off-Peak kWh	0.02211	0.02615
Generation - Winter		
On-Peak kWh	0.12308	0.18410
Off-Peak kWh	0.01911	0.02515
Transmission - kWh	0.01097	0.01097
Delivery kWh	0.03113	0.03117
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200

Transition TOU-D Bundled Rates	ECT-1R	ECT-2
Summer		
BSC $/day	0.643	0.643
kW	15.69	15.61
On-Peak kWh	0.08490	0.10256
Off-Peak kWh	0.04730	0.05109
Winter		
BSC $/day	0.643	0.643
kW	10.89	10.76
On-Peak kWh	0.06470	0.06647
Off-Peak kWh	0.04594	0.04750
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.05332	0.07264
Off-Peak kWh	0.01572	0.02117
kW	11.17500	10.40900
Generation - Winter		
On-Peak kWh	0.03128	0.03435
Off-Peak kWh	0.01252	0.01538
kW	8.22200	7.98000
Transmission - kWh	0.01097	0.01097
Delivery		
Summer kWh	0.01785	0.01619
Summer kW	4.51600	5.20500
Winter kWh	0.01969	0.01839
Winter kW	2.66300	2.77600
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200
Total Non-timed kWh		
Summer kWh	0.03156	0.02992
Winter kWh	0.03342	0.03212

Settlement Rate Summary for Residential Rates

Solar Legacy E-12 Bundled Rates	
Summer	
BSC $/day	0.330
0-400 kWh	0.11161
401-800 kWh	0.15920
801-3000 kWh	0.18627
< 3000 kWh	0.19863
Winter	
BSC $/day	0.330
All kWh	0.10851
Unbundled Rates	
Generation - Summer	
1st 400 kWh	0.06676
Next 400 kWh	0.11435
Next 2200 kWh	0.14142
All other kWh	0.15378
Generation Winter - kWh	0.06366
Transmission - kWh	0.01097
Delivery kWh	0.03112
System Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.07300
Metering	0.10400
Billing	0.08100
Meter reading	0.07200

Solar Legacy TOU-E Bundled Rates	ET-1	ET-2
Summer		
BSC $/day	0.643	0.643
On-Peak kWh	0.20697	0.28205
Off-Peak kWh	0.06697	0.07105
Winter		
BSC $/day	0.643	0.643
On-Peak kWh	0.16794	0.22900
Off-Peak kWh	0.06397	0.07005
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.16211	0.23715
Off-Peak kWh	0.02211	0.02615
Generation - Winter		
On-Peak kWh	0.12308	0.18410
Off-Peak kWh	0.01911	0.02515
Transmission - kWh	0.01097	0.01097
Delivery kWh	0.03113	0.03117
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200
Total untimed kWh	0.04486	0.04490

Settlement Rate Summary for Residential Rates

Solar Legacy TOU-D Bundled Rates	ECT-1R	ECT-2
Summer		
BSC $/day	0.643	0.643
kW	15.69	15.61
On-Peak kWh	0.08490	0.10256
Off-Peak kWh	0.04730	0.05109
Winter		
BSC $/day	0.643	0.643
kW	10.89	10.76
On-Peak kWh	0.06470	0.06647
Off-Peak kWh	0.04594	0.04750
Unbundled Rates		
Generation - Summer		
On-Peak kWh	0.05332	0.07264
Off-Peak kWh	0.01572	0.02117
kW	11.17500	10.40900
Generation - Winter		
On-Peak kWh	0.03128	0.03435
Off-Peak kWh	0.01252	0.01538
kW	8.22200	7.98000
Transmission - kWh	0.01097	0.01097
Delivery		
Summer kWh	0.01785	0.01619
Summer kW	4.51600	5.20500
Winter kWh	0.01969	0.01839
Winter kW	2.66300	2.77600
System Benefits - kWh	0.00276	0.00276
BSC $/day		
Customer accounts	0.27500	0.27500
Metering	0.21500	0.21500
Billing	0.08100	0.08100
Meter reading	0.07200	0.07200
Total Non-timed kWh		
Summer kWh	0.03156	0.02992
Winter kWh	0.03342	0.03212

Settlement Rate Summary for General Service Rates

E-20 House of Worship
Bundled Rates

Summer	
BSC $/day	2.020
kW on-peak	3.800
kW excess	2.400
On-peak kWh	0.15458
Off-peak kWh	0.07519
Winter	
BSC $/day	2.020
kW on-peak	3.800
kW excess	2.400
On-peak kWh	0.13626
Off-peak kWh	0.06748
Minimum	
BSC(Days)	2.020
KW	3.101
Unbundled Rates	
Generation	
kWh summer - on	0.11390
kWh summer - off	0.03451
kWh winter - on	0.09558
kWh winter - off	0.02680
Delivery kW - on	0.930
Delivery kW - excess	2.400
Delivery kWh	0.03792
Transmission - kW - on	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	
Metering - instrument rated	1.477
Metering - primary	
Metering - Transmission	

E-30 Non-Metered
Bundled Rates

Summer	
BSC $/day	0.405
kWh	0.13791
Winter	
BSC $/day	0.405
kWh	0.12443
Unbundled Rates	
Generation - Summer	
kWh	0.07972
Generation - Winter	
kWh	0.06624
Transmission	0.00794
Delivery	0.04749
Systems Benefits	0.00276
BSC $/day	
Customer accounts	0.375
Billing	0.030

E-32 XS D
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kW Secondary	6.900
kW Primary	4.300
kWh secondary	0.10549
kWh- primary	0.09951
Winter	
kW Secondary	6.90
kW Primary	4.30
kWh secondary	0.08631
kWh- primary	0.08051
Unbundled Rates	
Generation	
Summer kWh	0.08081
Winter kWh	0.06181
Delivery - Summer	
kWh secondary	0.01398
kWh- primary	0.00800
kW secondary	6.900
kW primary	4.300
Delivery - Winter	
kWh secondary	0.01380
kWh- primary	0.00800
kW secondary	6.900
kW primary	4.300
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-32 XS
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kWh secondary tier 1	0.13514
kWh secondary tier 2	0.07612
kWh primary tier 1	0.13195
kWh primary tier 2	0.07264
Winter	
kWh secondary tier 1	0.11797
kWh secondary tier 2	0.05864
kWh primary tier 1	0.11476
kWh primary tier 2	0.05545
Unbundled Rates	
Generation - Summer	
kWh tier 1	0.08390
kWh tier 2	0.05240
Generation - Winter	
kWh tier 1	0.06680
kWh tier 2	0.03529
Delivery - Summer	
kWh tier 1 - secondary	0.04054
kWh tier 2 - secondary	0.01302
kWh tier 1 - primary	0.03735
kWh tier 2 - primary	0.00954
Delivery - Winter	
kWh tier 1 - secondary	0.04047
kWh tier 2 - secondary	0.01265
kWh tier 1 - primary	0.03726
kWh tier 2 - primary	0.00946
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

Solar billing determinants
E-32 XS
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kWh secondary tier 1	0.13514
kWh secondary tier 2	0.10762
kWh primary tier 1	0.13195
kWh primary tier 2	0.10414
Winter	
kWh secondary tier 1	0.11797
kWh secondary tier 2	0.09015
kWh primary tier 1	0.11476
kWh primary tier 2	0.08696
Unbundled Rates	
Generation - Summer	
kWh tier 1	0.08390
kWh tier 2	0.08390
Generation - Winter	
kWh tier 1	0.06680
kWh tier 2	0.06680
Delivery - Summer	
kWh tier 1 - secondary	0.04054
kWh tier 2 - secondary	0.01302
kWh tier 1 - primary	0.03735
kWh tier 2 - primary	0.00954
Delivery - Winter	
kWh tier 1 - secondary	0.04047
kWh tier 2 - secondary	0.01265
kWh tier 1 - primary	0.03726
kWh tier 2 - primary	0.00946
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

E-32 S
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW tier 1 - secondary	11.360
kW tier 2 - secondary	6.608
kW tier 1 - primary	10.627
kW tier 2 - primary	5.875
Summer	
kWh secondary tier 1	0.10828
kWh secondary tier 2	0.06535
Winter	
kWh secondary tier 1	0.09126
kWh secondary tier 2	0.04836
Unbundled Rates	
Generation - Summer	
kWh tier 1	0.09658
kWh tier 2	0.05365
Generation - Winter	
kWh tier 1	0.07956
kWh tier 2	0.03666
Delivery	
kW tier 1 - secondary	8.490
kW tier 2 - secondary	3.738
kW tier 1 - primary	7.757
kW tier 2 - primary	3.005
kWh	0.00894
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-32 M
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Transmission meter	36.795
Demand	
kW tier 1 - secondary	12.124
kW tier 2 - secondary	6.935
kW tier 1 - primary	11.226
kW tier 2 - primary	6.197
kW tier 1 - transmission	9.056
kW tier 2 - transmission	3.869
Summer	
kWh secondary tier 1	0.10532
kWh secondary tier 2	0.06475
Winter	
kWh secondary tier 1	0.08921
kWh secondary tier 2	0.04863

Unbundled Rates

Generation - Summer	
kWh tier 1	0.09101
kWh tier 2	0.05044
Generation - Winter	
kWh tier 1	0.07490
kWh tier 2	0.03432
Delivery	
kW tier 1 - secondary	9.25400
kW tier 2 - secondary	4.06500
kW tier 1 - primary	8.35600
kW tier 2 - primary	3.32700
kW tier 1 - transmission	6.18600
kW tier 2 - transmission	0.99900
kWh	0.01155
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252
kWh Schools discount	-0.0024

E-32 L
Bundled Rates

BSC $/day	
Self contained meter	3.060
Instrument rated meter	3.920
Primary meter	6.847
Transmission meter	38.695
Demand	
kW tier 1 - secondary	25.372
kW tier 2 - secondary	17.605
kW tier 1 - primary	23.049
kW tier 2 - primary	16.411
kW tier 1 - transmission	17.624
kW tier 2 - transmission	11.753
Summer	
kWh	0.05540
Winter	
kWh	0.03712

Unbundled Rates

Generation - Summer	
kWh	0.05264
Generation - Winter	
kWh	0.03436
Generation - kW	5.49600
Delivery	1.36
kW tier 1 - secondary	17.00600
kW tier 2 - secondary	9.23900
kW tier 1 - primary	14.68300
kW tier 2 - primary	8.04500
kW tier 1 - transmission	9.25800
kW tier 2 - transmission	3.38700
kWh	-
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	2.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252
kWh aggregation discount	-0.0024
kWh Schools discount	-0.0024

E-34
Bundled Rates

BSC $/day	
Self contained meter	4.262
Instrument rated meter	5.122
Primary meter	8.049
Transmission meter	39.897
Demand	
Secondary	22.009
Primary	20.675
Transmission	14.088
Military	15.051
kWh	0.03972

Unbundled Rates

Generation	
kWh	0.03696
kW	10.464
Delivery - kW	
Secondary	8.309
Primary	6.975
Transmission	0.388
Military	1.351
Transmission - kW	3.236
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	3.606
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252

Settlement Rate Summary for General Service Rates

E-35
Bundled Rates

BSC $/day	
Self contained meter	4.262
Instrument rated meter	5.122
Primary meter	8.049
Transmission meter	39.897
Demand	
Secondary on peak	19.229
off peak	2.975
Primary on peak	17.947
off peak	2.847
Transmission on peak	11.323
off peak	2.183
Military on peak	13.103
off peak	2.361
kWh on peak	0.04483
kWh off peak	0.03550
Unbundled Rates	
Generation	
kWh on peak	0.04207
kWh off peak	0.03274
kW on peak	7.49800
kW off peak	2.12600
Delivery - kW	
Secondary on peak	8.49500
off peak	0.84900
Primary on peak	7.21300
off peak	0.72100
Transmission on peak	0.58900
off peak	0.05700
Military on peak	2.36900
off peak	0.23500
Transmission - kW	3.236
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	3.606
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - Transmission	36.252

E-221
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW secondary	4.754
kWh	
Tier 1	0.10640
Tier 2	0.07336
Unbundled Rates	
Generation	
kWh - Tier 1	0.07675
kWh - Tier 2	0.06115
kW	0.99600
Delivery	
kW Secondary	0.88800
kWh Secondary Tier 1	0.02689
kWh Secondary Tier 2	0.00945
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

E-221 8 T
Bundled Rates

BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW secondary on-peak	6.617
kW secondary off-peak	4.410
kWh	
on-peak	0.08967
off-peak	0.04808
Unbundled Rates	
Generation	
kWh - on-peak	0.08517
kWh - off-peak	0.04358
kW - on-peak	2.20714
kW - off-peak	-
Delivery	
kW Secondary On and Off peak	1.54000
kWh	0.00174
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404

Settlement Rate Summary for General Service Rates

E-32 TOU XS

Bundled Rates	
BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Summer	
kWh - secondary - on	0.13800
kWh - secondary - off	0.10321
kWh - primary - on	0.13600
kWh - primary - off	0.09700
kW - secondary - on	4.546
kW - secondary - off	2.599
kW - primary - on	3.951
kW - primary - off	1.565
Winter	
kWh - secondary - on	0.10800
kWh - secondary - off	0.08021
kWh - primary - on	0.10600
kWh - primary - off	0.07400
kW - secondary - on	4.546
kW - secondary - off	2.599
kW - primary - on	3.951
kW - primary - off	1.565

Unbundled Rates	
Generation - Summer	
kWh - on	0.08100
kWh - off	0.06700
kW - on	2.95100
kW - off	1.51500
Generation - Winter	
kWh - on	0.05100
kWh - off	0.04400
kW - on	2.951
kW - off	1.515
Delivery	
kWh - secondary - on	0.05700
kWh - secondary - off	0.03621
kWh - primary - on	0.05500
kWh - primary - off	0.03000
kW - secondary - on	1.595
kW - secondary - off	1.084
kW - primary - on	1.000
kW - primary - off	0.050
Transmission - kWh	0.00794
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

E-32 TOU S

Bundled Rates	
BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Demand	
kW tier 1 - secondary - on	19.977
kW tier 2 - secondary - on	10.225
kW tier 1 - secondary - off	7.879
kW tier 2 - secondary - off	2.715
kW tier 1 - primary - on	19.004
kW tier 2 - primary - on	10.081
kW tier 1 - primary - off	6.657
kW tier 2 - primary - off	2.548
Summer	
kWh - on	0.07161
kWh - off	0.05436
Winter	
kWh - on	0.05601
kWh - off	0.04121

Unbundled Rates	
Generation - Summer	
kWh - on	0.06885
kWh - off	0.05160
Generation - Winter	
kWh - on	0.05325
kWh - off	0.03845
Generation - kW	
kW - on	4.83700
kW - off	1.84000
Delivery	
kW tier 1 - secondary - on	12.27000
kW tier 2 - secondary - on	2.51800
kW tier 1 - secondary - off	6.03900
kW tier 2 - secondary - off	0.87500
kW tier 1 - primary - on	11.29700
kW tier 2 - primary - on	2.37400
kW tier 1 - primary - off	4.81700
kW tier 2 - primary - off	0.70800
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
kWh Schools discount	-0.0024

E-32 TOU M

Bundled Rates	
BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Transmission meter	36.795
Demand	
kW tier 1 - secondary - on	18.190
kW tier 2 - secondary - on	11.744
kW tier 1 - secondary - off	6.742
kW tier 2 - secondary - off	3.327
kW tier 1 - primary - on	17.546
kW tier 2 - primary - on	11.647
kW tier 1 - primary - off	5.934
kW tier 2 - primary - off	3.216
kW tier 1 - transmission - on	16.394
kW tier 2 - transmission - on	11.250
kW tier 1 - transmission - off	5.022
kW tier 2 - transmission - off	3.066
Summer	
kWh - on	0.07170
kWh - off	0.05952
Winter	
kWh - on	0.05783
kWh - off	0.04566

Unbundled Rates	
Generation - Summer	
kWh - on	0.05756
kWh - off	0.04538
Generation - Winter	
kWh - on	0.04369
kWh - off	0.03152
Generation - kW	
kW - on	4.91300
kW - off	1.87000
Delivery	
kW tier 1 - secondary - on	10.40700
kW tier 2 - secondary - on	3.96100
kW tier 1 - secondary - off	4.87200
kW tier 2 - secondary - off	1.45700
kW tier 1 - primary - on	9.76300
kW tier 2 - primary - on	3.86400
kW tier 1 - primary - off	4.06400
kW tier 2 - primary - off	1.34600
kW tier 1 - transmission - on	8.61100
kW tier 2 - transmission - on	3.46700
kW tier 1 - transmission - off	3.15200
kW tier 2 - transmission - off	1.19600
kWh	0.01138
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-32 TOU L

Bundled Rates	
BSC $/day	
Self contained meter	3.060
Instrument rated meter	3.920
Primary meter	6.847
Transmission meter	38.695
Demand	
kW tier 1 - secondary - on	17.508
kW tier 2 - secondary - on	11.795
kW tier 1 - secondary - off	6.396
kW tier 2 - secondary - off	3.370
kW tier 1 - primary - on	16.936
kW tier 2 - primary - on	11.710
kW tier 1 - primary - off	5.679
kW tier 2 - primary - off	3.272
kW tier 1 - transmission - on	15.916
kW tier 2 - transmission - on	10.478
kW tier 1 - transmission - off	4.871
kW tier 2 - transmission - off	3.137
Summer	
kWh - on	0.07018
kWh - off	0.05730
Winter	
kWh - on	0.05552
kWh - off	0.04264
Unbundled Rates	
Generation - Summer	
kWh - on	0.05534
kWh - off	0.04246
Generation - Winter	
kWh - on	0.04068
kWh - off	0.02780
Generation - kW	
kW - on	5.98000
kW - off	2.27500
Delivery	
kW tier 1 - secondary - on	8.658
kW tier 2 - secondary - on	2.945
kW tier 1 - secondary - off	4.121
kW tier 2 - secondary - off	1.095
kW tier 1 - primary - on	8.086
kW tier 2 - primary - on	2.860
kW tier 1 - primary - off	3.404
kW tier 2 - primary - off	0.997
kW tier 1 - transmission - on	7.066
kW tier 2 - transmission - on	1.628
kW tier 1 - transmission - off	2.596
kW tier 2 - transmission - off	0.862
kWh	0.01208
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	2.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh aggregation discount	-0.0024
kWh Schools discount	-0.0024

GS-Schools M

Bundled Rates	
BSC $/day	
Self contained meter	1.160
Instrument rated meter	2.020
Primary meter	4.947
Transmission meter	36.795
Demand	
kW tier 1 - secondary	11.816
kW tier 2 - secondary	6.802
kW tier 1 - primary	11.044
kW tier 2 - primary	6.028
kW tier 1 - transmission	8.853
kW tier 2 - transmission	3.839
Summer - Peak	
kWh - on	0.18571
kWh - shoulder	0.13746
kWh - off	0.06920
Summer - Shoulder	
kWh - on	0.16032
kWh - shoulder	0.11865
kWh - off	0.05952
Winter	
kWh - on	0.12415
kWh - shoulder	0.09186
kWh - off	0.04617
Unbundled Rates	
Generation - Summer Peak	
kWh - on	0.16003
kWh - shoulder	0.11178
kWh - off	0.04352
Generation - Summer Shoulder	
kWh - on	0.13464
kWh - shoulder	0.09297
kWh - off	0.03384
Generation - Winter	
kWh - on	0.09847
kWh - shoulder	0.06618
kWh - off	0.02049
Generation - kW	-
kW	-
Delivery	
kW tier 1 - secondary	8.946
kW tier 2 - secondary	3.932
kW tier 1 - primary	8.174
kW tier 2 - primary	3.158
kW tier 1 - transmission	5.983
kW tier 2 - transmission	0.969
kWh	0.02292
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	0.504
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh Schools discount	-0.0024

GS-Schools L

Bundled Rates	
BSC $/day	
Self contained meter	3.060
Instrument rated meter	3.920
Primary meter	6.847
Transmission meter	38.695
Demand	
kW tier 1 - secondary	11.564
kW tier 2 - secondary	6.661
kW tier 1 - primary	10.804
kW tier 2 - primary	5.905
kW tier 1 - transmission	8.666
kW tier 2 - transmission	3.761
Summer - Peak	
kWh - on	0.16704
kWh - shoulder	0.12360
kWh - off	0.06809
Summer - Shoulder	
kWh - on	0.14419
kWh - shoulder	0.10667
kWh - off	0.05163
Winter	
kWh - on	0.11163
kWh - shoulder	0.08257
kWh - off	0.04541
Unbundled Rates	
Generation - Summer Peak	
kWh - on	0.14913
kWh - shoulder	0.10569
kWh - off	0.05018
Generation - Summer Shoulder	
kWh - on	0.12628
kWh - shoulder	0.08876
kWh - off	0.03372
Generation - Winter	
kWh - on	0.09372
kWh - shoulder	0.06466
kWh - off	0.02750
Generation - kW	
kW	-
Delivery	
kW tier 1 - secondary	8.694
kW tier 2 - secondary	3.791
kW tier 1 - primary	7.934
kW tier 2 - primary	3.035
kW tier 1 - transmission	5.796
kW tier 2 - transmission	0.891
kWh	0.01515
Transmission - kW	2.870
Systems Benefits - kWh	0.00276
BSC $/day	
Customer accounts	2.404
Billing	0.030
Meter reading	0.009
Metering - self contained	0.617
Metering - instrument rated	1.477
Metering - primary	4.404
Metering - transmission	36.252
kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-59 Bundled Rates		SL Contract Bundled Rates		E-67 Bundled Rates	
lamp	3.00	Delivery Point	17.73	kWh	0.05594
kWh	0.06563	kWh	0.09142		

Settlement Rate Summary for General Service Rates

XHLF Rate
Bundled Rates

BSC $/day	
Instrument rated met	5.122
Primary meter	8.049
Transmission meter	39.897
Demand (kW)	
Secondary	17.950
Primary	16.609
Transmission	12.917
kWh	0.037610
Unbundled Rates	
Generation - kWh	
kW	9.27400
kWh	0.03485
Delivery - kW (primary)	
Secondary	5.44000
Primary	4.09900
Transmission	0.40700
Transmission - kW	3.236
Systems Benefits - kV	0.00276
BSC (day)	
Customer accounts	3.606
Billing	0.030
Meter reading	0.009
Metering - instrumen	1.477
Metering - primary	4.404
Metering - Transmissi	36.252

E-36 XL
Bundled Rates

Basic Service Charge	7,436
T&D Capacity Charge:	
Secondary	5.584
Primary	5.388
Transmission	1.743
Hourly Proxy	
Power Supply kWh	0.00061

E-36 M (Rider)
Bundled Rates

BSC $/day	
E32-XS option	
Self contained meter	3.764
Instrument rated meter	4.602
Primary meter	13.037
E32-L option	
Self contained meter	3.764
Instrument rated meter	4.602
Primary meter	13.037
Transmision meter	44.885
Unbundled Rates	
BSC (day)	
E32-XS option	
Customer accounts:	
Self contained meter	3.14700
Instrument rated meter	3.12500
Primary meter	8.63300
Metering:	
Self contained meter	0.61700
Instrument rated meter	1.47700
Primary meter	4.40400
Meter Reading	0.00900
Billing	0.03000
kWh rate - summer	0.13514
kWh rate - winter	0.11797
E32-L option	
Customer accounts:	
Self contained meter	3.14700
Instrument rated meter	3.12500
Primary meter	8.63300
Metering:	
Self contained meter	0.61700
Instrument rated meter	1.47700
Primary meter	4.40400
Transmision meter	36.25200
Meter Reading	0.00900
Billing	0.03000

Settlement Rate Summary for General Service Rates

E-56 Back-up Power Charges		Rider PPR	
Rate Schedule E-34	0.647	Extra Large	0.05142
Rate Schedule E-32	0.131	Large - summer	0.06080
Excess power charge		Large - winter	0.04480
secondary	0.54802	Medium - summer	0.06623
primary	0.52019	Medium - winter	0.05220
transmission	0.38187		

Appendix H

Resource Comparison Proxy
Plan of Administration

Table of Contents

1. General Description

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

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

2. Customer Billing

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

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

3. Resource Comparison Proxy Purchase Rate

The RCP will be determined as follows:

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

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

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

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

4. Definitions

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

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

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

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

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

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

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

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

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

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

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

5. System Eligibility

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

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

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

SPECIAL CASES

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

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

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

6. Calculation of Resource Comparison Proxy Purchase Rate

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

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

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

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

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

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

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

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

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

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

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

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

7. Procedural Timeline

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

8. Confidential Data

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

9. Schedules

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

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

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

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

Competitively/Highly Confidential
Page 1 of 6

= Competitively/Highly Confidential

Competitively/Highly Confidential | Competitively/Highly Confidential

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

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

Arizona Public Service Company

Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost

Competitively/Highly Confidential

Page 2 of 6

Project	RFP Year	Start Date	Start Year	Levelized Cost (Base Year)	GWH (1st Year)
= Competitively/Highly Confidential					

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

Competitively/Highly Confidential
Page 3 of 6

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

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

Competitively/Highly Confidential
Page 4 of 6

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

Arizona Public Service Company
Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost ($000)

Competitively/Highly Confidential
Page 5 of 6

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

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

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

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

AVAILABILITY

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

DESCRIPTION

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

The purchase rates will be determined as follows:

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

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

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

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

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

aps

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

PURCHASE RATES

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

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

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

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. Electricity must be generated using solar photovoltaic panels;
2. The generator must be interconnected to the Company's distribution grid;
3. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;
4. The facility's nameplate capacity cannot be larger than the following electrical service limits:
    a. For 200 Amp service, a maximum of 15 kW-dc.
    b. For 400 Amp service, a maximum of 30 kW-dc.
    c. For 600 Amp service, a maximum of 45 kW-dc.
    d. For 800 Amp service and above, a maximum of 60 kW-dc; and
5. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

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

SPECIAL CASES

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

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

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

SERVICE DETAILS

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

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

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

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

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

AVAILABILITY

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

DESCRIPTION

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

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

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

PURCHASE RATES

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

$0.02895	per kWh

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

BILLING DETAILS

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

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

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

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

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

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

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

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

SERVICE DETAILS

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

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

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

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

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

   b. Uses renewable resources, as defined by the Arizona Corporation Commission, including a fuel cell with the chemical reaction derived from renewable resources

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

or a combined heat and power (CHP) facility as defined by A.A.C. R14-2-2302, to generate energy; and

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

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

aps

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

AVAILABILITY

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

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

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

DESCRIPTION

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

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

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

PURCHASE RATES

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

$0.02895	per kWh

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

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

BILLING DETAILS

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

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

RESIDENTIAL GRANDFATHERING PROGRAM

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

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

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

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

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

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

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

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

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

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

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

SERVICE DETAILS

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

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

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

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

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

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

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

Appendix I

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RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedules E-34 or E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

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

Bundled Charges

Basic Service Charges (only one applies)		
For service through Self-Contained Meters	$3.060	per day
For service through Instrument-Rated Meters	$3.920	per day
For service at Primary Voltage	$6.847	per day
For service at Transmission Voltage	$38.695	per day

Demand Charges (only one set applies)			
Secondary	First 100 kW	$25.372	per kW
	All additional kW	$17.605	per kW
Primary	First 100 kW	$23.049	per kW
	All additional kW	$16.411	per kW
Transmission	First 100 kW	$17.624	per kW
	All additional kW	$11.753	per kW

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RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

	Summer	Winter	
Energy Charge	$0.05540	$0.03712	per kWh

Unbundled Components of the Bundled Charges

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

Basic Service Charge Components

Customer Accounts Charge	$2.404	per day
Meter Reading	$0.009	per day
Billing	$0.030	per day
Metering* (only one applies)		
Self Contained Meters	$0.617	per day
Instrument-Rated Meters	$1.477	per day
Primary	$4.404	per day
Transmission	$36.252	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		$2.870	per kW
Generation		$5.496	per kW
Delivery - Secondary	First 100 kW	$17.006	per kW
	All additional kW	$9.239	per kW
Delivery - Primary	First 100 kW	$14.683	per kW
	All additional kW	$8.045	per kW
Delivery - Transmission	First 100 kW	$9.258	per kW
	All additional kW	$3.387	per kW

Energy Charge Components

System Benefits	$0.00276	per kWh
Delivery	$0.00000	per kWh

	Summer	Winter	
Generation	$0.05264	$0.03436	per kWh