ORIGINAL

0000178645

RECEIVED
AZ CORP COMMISSION
DOCKET CONTROL

2017 APR -3 P 3: 57

Arizona Corporation Commission
DOCKETED
APR 3 2017
DOCKETED BY
GB

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

TOM FORESE– Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD DUNN

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-16-0036
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-16-0123 **STAFF'S NOTICE OF FILING REMAINING APPENDICES TO THE SETTLEMENT AGREEMENT**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby files, on behalf of all the Signatories, the remaining Appendices to the Proposed Settlement Agreement, in the above-captioned Dockets.

On March 27, 2017, Staff filed Appendices F and H with the proposed Settlement Agreement. The remaining Appendices attached hereto include A through E, G, and I through R.

RESPECTFULLY SUBMITTED this 3rd day of April, 2017.

Maureen A. Scott, Senior Staff Counsel
Wesley C. Van Cleve, Staff Counsel
Charles H. Hains, Staff Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007
(602) 542-3402

CERTIFICATE OF SERVICE

On this 3rd day of April, 2017, the foregoing document was filed with Docket Control as a Utilities Division Motion - Miscellaneous, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

Thomas Jernigan
Federal Executive Agencies
U.S. Airforce Utility Law Field Support Center
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
thomas.jernigan.3@us.af.mil
ebony.payton.crt@us.af.mil
andrew.unsicker@us.af.mil
lanny.zieman.1@us.af.mil
natalie.cepak.2@us.af.mil
Consented to Service by Email

Nicholas J. Enoch
LUBIN & ENOCH, PC
349 N. Fourth Ave.
Phoenix Arizona 85003

T. Hogan
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
514 W. Roosevelt Street
Phoenix, Arizona 85003

Timothy J. Sabo
SNELL & WILMER, LLP
One Arizona Center
400 East Van Buren, 19th Floor
Phoenix, Arizona 85004
tsabo@swlaw.com
jhoward@swlaw.com
docket@swlaw.com
pwalker@conservamerica.org
Consented to Service by Email

Thomas A Loquvam
PINNACLE WEST CAPITOL CORPORATION
400 N. 5Th St, MS 8695
Phoenix, Arizona 85004
Thomas.Loquvam@pinnaclewest.com
Thomas.Mumaw@pinnaclewest.com
Melissa.Krueger@pinnaclewest.com
Amanda.Ho@pinnaclewest.com
Debra.Orr@aps.com
prefo@swlaw.com
Consented to Service by Email

Cynthia Zwick
ARIZONA COMMUNITY ACTION ASSOCIATION
2700 N. Third St. - 3040
Phoenix, Arizona 85004
czwick@azcaa.org
khengehold@azcaa.org
Consented to Service by Email

Daniel Pozefsky
RUCO
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Janet Wagner
ARIZONA CORPORATION COMMISSION
1200 W Washington
Phoenix, Arizona 85007
Legaldiv@azcc.gov
JXHatch-Miller@azcc.gov
chains@azcc.gov
wvancleve@azcc.gov
eabinah@azcc.gov
tford@azcc.gov
evanepps@azcc.gov
cfitzsimmons@azcc.gov
kchristine@azcc.gov
mscott@azcc.gov
Consented to Service by Email

Anthony Wanger
IO DATA CENTERS, LLC
615 N. 48th St
Phoenix, Arizona 85008

Giancarlo Estrada
KAMPER ESTRADA, LLP
3030 N. 3rd Street, Suite 770
Phoenix, Arizona 85012
gestrada@law.phx.com
kfox@kfwlaw.com
kcrandall@eq-research.com
Consented to Service by Email

Garry D Hays
LAW OFFICES OF GARRY D. HAYS, PC
2198 East Camelback Road, Suite 305
Phoenix, Arizona 85016
ghays@lawgdh.com
Consented to Service by Email

John William Moore, Jr.
MOORE BENHAM & BEAVER, PLC
7321 N. 16th Street
Phoenix, Arizona 85020

Craig A. Marks
CRAIG A. MARKS, PLC
10645 N. Tatum Blvd., Suite 200-676
Phoenix, Arizona 85028
Craig.Marks@azbar.org
Pat.Quinn47474@gmail.com
Consented to Service by Email

Dennis M. Fitzgibbons
FITZGIBBONS LAW OFFICES, PLC
P.O. Box 11208
Casa Grande, Arizona 85230
denis@fitzgibbonslaw.com
Consented to Service by Email

Thomas E. Stewart
GRANITE CREEK POWER &
GAS/GRANITE CREEK FARMS
5316 East Voltaire Avenue
Scottsdale, Arizona 85254-3643
tom@gcfaz.com
Consented to Service by Email

Albert E. Gervenack
SUN CITY WEST PROPERTY OWNERS &
RESIDENTS ASSOCIAT
13815 Camino Del Sol
Sun City West, Arizona 85375
al.gervenack@porascw.org
rob.robbins@porascw.org
Bob.miller@porascw.org
Consented to Service by Email

Lawrence V. Robertson, Jr.
210 Continental Road, Suite 216A
Green Valley, Arizona 85622
tubaclawyer@aol.com
Consented to Service by Email

Charles Wesselhoft
Pima County Attorney's Office
32 North Stone Avenue, Suite 2100
Tucson, Arizona 85701
Charles.Wesselhoft@pcao.pima.gov
Consented to Service by Email

Robert Pickels, Jr.
Sedona City Attorney's Office
102 Roadrunner Drive
Sedona, Arizona 86336
rpickels@sedonaaz.gov
Consented to Service by Email

Kurt Boehm
BOEHM, KURTZ & LOWRY
36 E. Seventh St. Suite 1510
Cincinnati, Ohio 45202

Richard Gayer
526 W. Wilshire Dr.
Phoenix, Arizona 85003
rgayer@cox.net
Consented to Service by Email

Timothy M. Hogan
ARIZONA CENTER FOR LAW IN THE
PUBLIC INTERST
514 W. Roosevelt St.
Phoenix, Arizona 85003
thogan@aclpi.org
ken.wilson@westernresources.org
schlegelj@aol.com
ezuckerman@swenergy.org
bbaatz@aceee.org
briana@votesolar.org
cosuala@earthjustice.org
dbender@earthjustice.org
cfitzgerrell@earthjustice.org
Consented to Service by Email

Michael Patten
SNELL & WILMER, LLP
One Arizona Center
400 East Van Buren Street
Phoenix, Arizona 85004
mpatten@swlaw.com
jhoward@swlaw.com
docket@swlaw.com
BCarroll@tep.com
Consented to Service by Email

…

…

Albert H. Acken
One N. Central Ave, Ste. 1200
Phoenix, Arizona 85004
aacken@rcalaw.com
ssweeney@rcalaw.com
slofland@rcalaw.com
jjw@krsaline.com
Consented to Service by Email

Jay I. Moyes
MOYES SELLERS & HENDRICKS, LTD
1850 N. Central Ave. - 1100
Phoenix, Arizona 85004
JasonMoyes@law-msh.com
jimoyes@law-msh.com
jim@harcuvar.com
Consented to Service by Email

Greg Patterson
MUNGER CHADWICK
916 W. Adams Suite 3
Phoenix, Arizona 85007

Timothy La Sota
ARIZONA CORPORATION COMMISSION
Acting Director- Legal Division
1200 W. Washington
Phoenix, Arizona 85007
Legaldiv@azcc.gov
chains@azcc.gov
wvancleve@azcc.gov
eabinah@azcc.gov
tford@azcc.gov
evanepps@azcc.gov
cfitzsimmons@azcc.gov
kchristine@azcc.gov
mscott@azcc.gov
EAblinah@azcc.gov
Consented to Service by Email

Meghan H. Grabel
OSBORN MALEDON, PA
2929 N. Central Avenue Suite 2100
Phoenix, Arizona 85012
mgrabel@omlaw.com
gyaquinto@arizonaic.org
Consented to Service by Email

Patrick J. Black
FENNEMORE CRAIG, P.C.
2394 E. Camelback Rd, Ste. 600
Phoenix, Arizona 85016
pblack@fclaw.com
khiggins@energystrat.com
Consented to Service by Email

Scott S. Wakefield
HIENTON & CURRY, PLLC
5045 N 12th Street, Suite 110
Phoenix, Arizona 85014-3302
swakefield@hclawgroup.com
mlougee@hclawgroup.com
Stephen.chriss@wal-mart.com
Greg.tillman@walmart.com
chris.hendrix@wal-mart.com
Consented to Service by Email

Tom Harris
ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION
2122 W. Lone Cactus Dr. Suite 2
Phoenix, Arizona 85027
Tom.Harris@AriSEIA.org
Consented to Service by Email

Ann-Marie Anderson
WRIGHT WELKER & PAUOLE, PLC
10429 South 51st Street, Suite 285
Phoenix, Arizona 85044
aanderson@wwpfirm.com
sjennings@aarp.org
aallen@wwpfirm.com
john@johncoffman.net
Consented to Service by Email

Court S. Rich
ROSE LAW GROUP, PC
7144 E. Stetson Drive, Suite 300
Scottsdale, Arizona 85251
crich@roselawgroup.com
hslaughter@roselawgroup.com
cledford@mcdonaldcarano.com
Consented to Service by Email

Greg Eisert
SUN CITY HOME OWNERS ASSOCIATION
10401 W. Coggins Drive
Sun City, Arizona 85351
gregeisert@gmail.com
steven.puck@cox.net
Consented to Service by Email

Patricia C. Ferre
P.O. Box 433
Payson, Arizona 85547
pFerreact@mac.com
Consented to Service by Email

L. Robertson, Jr.
210 Continental Road, Suite 216A
Green Valley Arizona 85622

Warren Woodward
200 Sierra Road
Sedona, Arizona 86336
w6345789@yahoo.com
Consented to Service by Email

By: Monica A. Martz for
Karyn Christine
Administrative Assistant

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) 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
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

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
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

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

Statement A

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
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)			Proposed (at 12/31/2015)		
	Investment	Net Salvage	Total	Investment	Net Salvage	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) Investment	Net Salvage	Total	Proposed (at 12/31/2015) 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

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

<u>a. Accounts</u>

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

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)

Line		Formula	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)													$ -	

Line		Value
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.

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.		January	February	March	April	May	XXXX Data 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

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

		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.	ACC	Total Co.	ACC	Total Co.	ACC
		(A)	(B)	(C)	(D)	(E)=(A)+(C)	(F)=(B)+(D)
1.	Gross Utility Plant in Service	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2.	Less: Accumulated Depreciation & Amort.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	Net Utility Plant in Service	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4.	Less: Total Deductions	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5.	Total Additions	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6.	Total Rate Base	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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				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.

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

Line No.	Description	Settlement Percentage of Incremental Gross Revenues (A)	TEAM Pro Forma 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

aps

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

aps

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.

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

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

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.

aps

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

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

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.

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

aps

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:

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

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

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:

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

aps

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)

aps

RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE

AVAILABILITY

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

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

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

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

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

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

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

DESCRIPTION

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

TIME PERIODS

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

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

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

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

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

CHARGES

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

Bundled Charges

Basic Service Charge	$0.493	per day

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

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.

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

ADJUSTMENTS

The bill will include the following adjustments:

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

RATE RIDERS

Eligible rate riders for this rate schedule are:

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

SERVICE DETAILS

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

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

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

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

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

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

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

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

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

Arizona Public Service Company

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

Competitively/Highly Confidential

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

= Competitively/Highly Confidential

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

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

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

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

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

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

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

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

RATE RIDER 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.

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).

aps

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).

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

AVAILABILITY

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

DESCRIPTION

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

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

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

PURCHASE RATES

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

$0.02895	per kWh

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

BILLING DETAILS

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

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

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

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

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

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

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

SERVICE DETAILS

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

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

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

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

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

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

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

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

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

AVAILABILITY

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

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

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

DESCRIPTION

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

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

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

PURCHASE RATES

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

$0.02895	per kWh

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

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.

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

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

aps

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

aps

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

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

For billing purposes, the kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of $0.0024 per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

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 Tax Expense Adjustment Charge, Adjustment Schedule TEAM.

7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

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:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements Service
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

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.

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedule 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) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule Time-of-Use 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

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
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 Charge (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 On-Peak kW	508	per kW
	All additional On-Peak kW	$11.795	per kW
	First 100 Off-Peak kW	$6.396	per kW
	All additional Off-Peak kW	$3.370	per kW
Primary	First 100 On-Peak kW	$16.936	per kW
	All additional On-Peak kW	$11.710	per kW
	First 100 Off-Peak kW	$5.679	per kW
	All additional Off-Peak kW	$3.272	per kW
Transmission	First 100 On-Peak kW	$15.916	per kW
	All additional On-Peak kW	$10.478	per kW
	First 100 Off-Peak kW	$4.871	per kW
	All additional Off-Peak kW	$3.137	per kW

Energy Charges			
	Summer	Winter	
On-Peak	$0.07018	$0.05552	per kWh
Off-Peak	$0.05730	$0.04264	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

aps

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

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 On-Peak		$5.980	per kW
Generation Off-Peak		$2.275	per kW
Delivery - Secondary	First 100 On-Peak kW	$8.658	per kW
	All additional On-Peak kW	$2.945	per kW
	First 100 Off-Peak kW	$4.121	per kW
	All additional Off-Peak kW	$1.095	per kW
Delivery - Primary	First 100 On-Peak kW	$8.086	per kW
	All additional On-Peak kW	$2.860	per kW
	First 100 Off-Peak kW	$3.404	per kW
	All additional Off-Peak kW	$0.997	per kW
Delivery - Transmission	First 100 On-Peak kW	$7.066	per kW
	All additional On-Peak kW	$1.628	per kW
	First 100 Off-Peak kW	$2.596	per kW
	All additional Off-Peak kW	$0.862	per kW

Energy Charge Components

System Benefits Charge:	$0.00276	per kWh
Delivery Charge	$0.01208	Per kWh

	Summer	Winter	
Generation On-Peak	\$0.05534	\$0.04068	per kWh
Generation Off-Peak	\$0.04246	\$0.02780	per kWh

For billing purposes, the On-Peak kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during the On-Peak period during the billing period, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.

2. 80% of the highest On-Peak kW measured during the six summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

Off-peak kW will be based on the average kW supplied during the 15-minute period of maximum use during the Off-peak hours of the billing period, as determined from readings of the Company's meter.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of \$0.0024 per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

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 Tax Expense Adjustment Charge, Adjustment Schedule TEAM.

7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.

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:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

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.

RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR

AVAILABILITY

This rate schedule is available to Customers whose monthly maximum demand is 5,000 kW or more with a load factor of 92% or more for a minimum of nine months of the prior 12 month period.

Customers will be required to execute a service agreement or contract that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges, and other service details.

Qualifying Customers with monthly demands of 15,000 kW and greater may choose to be served with transmission level service by providing the Company with a contribution in aid of construction (CIAC) in lieu of purchasing transmission level facilities. The Customer will be required to execute a maintenance contract and share in the cost of replacement facilities. Under this option, the Company may also finance the CIAC at the Company's weighted average cost of capital established in its most recent rate case. This financing period will not exceed 10 years.

DESCRIPTION

This rate has three parts: a basic service charge, a demand (kW) charge consisting of the average kW supplied during the 15-minute period of maximum use during the billing period, and an energy (kWh) charge for the energy used for the entire month.

Monthly load factor will be established using the formula:

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

CHARGES

The monthly bill will be calculated at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Service

Customers Served at Secondary Voltage		
Basic Service Charge	$5.122	per day
Demand Charge	$17.950	per kW
Energy Charge	$0.03761	per kWh

RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR

Customers Served at Primary Voltage		
Basic Service Charge	$8.049	per day
Demand Charge	$16.609	per kW
Energy Charge	$0.03761	per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	$39.897	per day
Demand Charge	$12.917	per kW
Energy Charge	$0.03761	per kWh

Unbundled Standard Offer Service

Bundled Charges consists of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	$3.606	per day
Meter Reading	$0.009	per day
Billing	$0.030	per day
Meter (only one applies)		
Instrument-Rated Meter	$1.477	per day
Primary Meter	$4.404	per day
Transmission Meter	$36.252	per day
Demand Charge Components		
Transmission Charge	$3.236	per kW
Generation - Capacity	$9.274	per kW
Delivery (only one applies)		
Secondary Service	$5.440	per kW
Primary Service	$4.099	per kW
Transmission Service	$0.407	per kW
Energy Charge Components		
Generation - Fuel	$0.03485	per kWh
System Benefits	$0.00276	per kWh

The kW for billing will be the greater of:

a. The average kW supplied during the 15-minute period of maximum use during the monthly billing period; or

b. The minimum kW specified in a service agreement.

MINIMUM BILL

The bill will not be less than the minimum amount specified in the Customer's service agreement or contract.

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. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
6. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Any applicable taxes and governmental fees that are assessed on APS's revenue, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

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

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.

3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of ± 95%.

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.

5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.

2. Daily metering charges apply to typical installations. Customers requiring specialized Equipment may incur additional metering charges that reflect the additional cost.

3. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the partial requirement rate riders.

4. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.

5. This schedule is not applicable to breakdown, standby, supplemental, residential or reseale service.

6. 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 the Company and billed to the Customer at the charges shown above.

7. 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).

Appendix J

aps

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

General Description

This Service Schedule provides the Terms and Conditions under which Arizona Public Service Company (APS or Company) may offer financial incentives to potential new commercial or industrial Customers or to existing commercial and industrial Customers who are adding significant new load.

Availability of this schedule is limited to the lesser of 100 MW of new and additional load or 50 new Customers.

The Customer must provide all requested information to the Company in order to demonstrate eligibility. The Company will evaluate all relevant information and will determine whether to offer the Customer an incentive.

Consistent with the Schedule, when the Company determines that it is appropriate to offer an incentive to an eligible Customer, an agreement will be executed with the Customer. The agreement will specify the incentive and other terms where different from the Company's other Service Schedules.

APS will file each agreement, along with a complete Customer Characteristics Report with Arizona Corporation Commission (Commission) Staff as a compliance filing. Each agreement filed with the Commission Staff will become effective 30 days after filing.

Any Customer information that the Company provides to Commission Staff on a confidential basis will be returned to the Company no later than 60 days after an application under this Schedule is filed.

1. **Eligibility Criteria**
   The Company will evaluate the following Customer characteristics prior to offering service under this Schedule to determine if the Customer is eligible for a financial incentive:

   1.1 Availability of Alternative Locations
   (A) Incentives are available only to Customers who have not located or expanded in the Company's service area before the Commission's review of the application and who would not locate or expand in the Company's service area without this Schedule's incentive.

   (B) The Customer must provide the Company with evidence that additional locations, outside the Company's service area, have been considered for location or expansion. This evidence must consist of written documentation including, but not limited to, detailed quantitative analyses performed by the Customer or consultants regarding the suitability of alternative locations.

(C) Based on the information provided, the Company will determine whether the Customer would reasonably locate elsewhere in the absence of the incentive. If so, the Customer will be deemed to have met this requirement.

1.2 Effects on Competitors

(A) Incentives will be available to the Customer only when existing Customers in the same line of business and market are not adversely impacted by the discounted rates.

(B) The Customer must provide a detailed description of goods and services produced, the technology employed, and the market(s) the Customer serves.

(C) Based on the provided information, along with knowledge of its customer base, the Company must reasonably verify that this requirement is satisfied for the Customer to be eligible for an incentive.

1.3 Customer Load Requirements

(A) To qualify for this Schedule, electric requirements for a new Customer must be at least 2 MW and existing Customers must add at least 1 MW of load. To determine Customer load, APS will consider both energy purchased from the Company and any energy generated by the Customer using cogeneration or small power production facilities.

(B) The Customer's monthly average load factor must be 55% or greater. This load factor criteria may be waived if one of the following apply:

1. The Customer's daily off-peak energy usage in kWh is greater than 50% of total monthly energy usage in kWh (off-peak hours will be defined using the applicable General Service Rate Schedule); or
2. The Customer's new or added load is interruptible and the Customer's peak load is at least 3 MW.

(C) Loads that do not operate in the summer months of June through September will be given special consideration when determining an applicable incentive.

(D) APS will assist the Customer to consider and employ state-of-the-art, cost-effective energy conservation and demand response measures at its facility. These measures may include efficiency motors, motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.

1.4 Economic Requirements

(A) The load must be economic, as calculated under the Company's current extension policy using standard rates.

(B) To be eligible for incentives under this schedule, a potential load must bring a significant number of jobs or ancillary business into Arizona. In conjunction with this criterion, capital investment by the Customer may also be considered.

(C) The Company will give particular consideration to Customers whose electric bills exceed 5% of their operating expenses.

2. Conflict of Interest.

2.1 In order to limit any potential conflict of interest, APS is required to submit an affidavit to Commission Staff for each Customer under consideration for service under this Service Schedule. This affidavit will include:

(A) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries, or one who has filled such role within the three-years prior to the effective date of the Customer's agreement, has or had any interest, direct or indirect, with any entity which has provided substantial services, including real estate broker services, to the Customer in connection with a proposed agreement under this Schedule; and

(B) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has or had any direct or indirect interest in any property owned in whole or in part by the Customer.

2.2 If the affidavit provided by APS is shown to be inaccurate, the Commission will, in future APS rate cases, impute as revenue the difference between the discounted rate and the tariffed rate which would otherwise apply to the Customer for the period during which the discount was in effect.

3. Rate Provisions

3.1 A Customer satisfying the requirements above may receive an incentive to locate in the Company's service territory. The incentive will be a discount from the Customer's otherwise applicable base electric bill (excluding taxes and adjustments).

3.2 The discounted charges will not be below the Company's marginal cost.

3.3 The discount may vary over the term of the Customer agreement.

3.4 The discount will not be larger than 25% of the Customer's total energy bill from the Company.

3.5 No discount will be provided from the minimum bill as computed under the Customer's otherwise applicable rate.

3.6 For current Customers adding load, the discount will apply only to the added load.

3.7 Any incentive available under this schedule will be limited to a specific period of six years or less.

3.8 The specific discount and the period over which the discount is applied will be determined after full evaluation of the Customer information as determined by the Company.

4. Customer Characteristic Report

Each agreement must be accompanied by a Customer Characteristic Report. The following information will be included in the Customer Characteristics Report:

4.1 **General Information**

(A) Customer name
(B) Customer contact name and address
(C) Dates of Customer application and Company decision
(D) New or existing Customer
(E) Proposed effective date of agreement

4.2 **Location Decision**

(A) Customer location
(B) Description of other locations considered
(C) Other locations of Customer's operations
(D) An affidavit from Customer demonstrating that the Customer would not locate or expand in Arizona absent the discounts
(E) Within ninety (90) days of the effective date of any agreement under this Schedule, the Customer must supply written documentation and analyses substantiating the affidavit provided under 4.2 (D)
(F) If the requirements of 4.2 (E) are not met within ninety (90) days of approval of the agreement, the agreement will be void

(G) Proportion of Customer's production and distribution expenses accounted for by electricity, by natural gas and by other energy sources (specify)

4.3 **Effects on Competitors**

(A) Nature of business, description and North American Industry Classification System (NAICS) code
(B) Number of other Customers in same business
(C) Market area served by Customer
(D) Description of effects on other Customers

4.4 **Load Characteristics**

(A) Size of load
(B) Annual load factor
(C) Off-peak operation
(D) Description of daily load shape
(E) Seasonality
(F) Interruptibility
(G) Permanency of load
(H) Estimated impact on system peak demand from the new load

4.5 **Energy Service Mix**

(A) Use of natural gas and other energy sources
(B) Description of energy efficiency measures including building design, processing and other
(C) Feasibility of cogeneration

4.6 **Rates**

(A) Applicable rate schedule
(B) Years discount will be in effect
(C) Percentage discount by year
(D) Estimated annual revenues
(E) Estimated annual incremental electricity production costs
(F) Support that the agreement meets the terms described in Rate Provisions Section 3.2 and 3.4

4.7 **Special Agreement Provisions**

(A) List of special provisions
(B) Reasons for special provisions

Appendix K

aps

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer customers who have an Aggregated Peak Load of 10 MW or more and are served under Rate Schedules E-34, E-35, E32-L, or E-32 TOU L. An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.

Customers must have interval metering, Advanced Metering Infrastructure, or an alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of customer load, 100 MW of which will be initially reserved for Customers with single-site peak demands of 20 MW or greater and with monthly average load factors above 70% unless not fully subscribed during the solicitation process.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-X.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the aggregated actual hourly metered load for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, customers may enroll on a first come first serve basis. After the initial lottery, if necessary, customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

Eligible customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer must apply for service under this rate rider schedule.

The Company will conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer must select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company must enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider must provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company will provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company will bill the customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, and APS will not request recovery of any unmitigated costs resulting from AG-X, if any, in its next rate case.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company will serve as the scheduling coordinator. The Generation Service Provider must provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

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

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

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

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company will provide the required power to the customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule if: (1) they provide one or more years notice to the Company; or (2) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to the Customers under the following conditions. The Company may elect to provide the customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain 1 year notice, at which time the Customer returns to the Company's Standard Generation Service under their applicable retail rate schedule. The returning customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;

2. Adjustment Schedule PSA-1 will not apply;

3. Adjustment Schedule EIS will not apply; and

4. The applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder will be applied to the customer's bill.

Schedule AG-X charges determined and billed by the Company include:

1. A monthly administrative management fee of $0.00180 per kWh applied to the customer's billed kWh;

2. A monthly reserve capacity charge of $5.540 per kW applied to 100% of the customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);

3. Returning Customer charge, where applicable, as described herein;

4. Generation Service Provider Default charge, where applicable, as described herein.

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

Schedule AG-X Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges will be charged at a rate within the minimum and maximum limits as follows:

    a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.

b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.

c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges will be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with Section IV under imbalance services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

Appendix L

Targets by Class
Settlement

	Target	Percent
Settlement revenue increase	94,624,000	3.28%
Application revenue increase	165,883,743	5.74%
ratio	57.0424%	
adjustor transfer	267,953,000	9.28%
Increase base rates (with adjustor transfer)	362,577,000	12.55%
GS - XS,S decrease to spread to non-res	123,826	0.014%
Schools discount	1,206,688	0.086%

Class	Base Rates ATY Revenue	Present % COS	Application Requested Increase	Step 1 Settlement Requested Increase	Step 2 Spread GS - XS,S hold	Step 3a Recover Schools Discount	Step 3b Receive Schools Discount	**Net Impact** Increase	Adjustor Transfers	Target **Increase Base Rates**	Actual **Increase Base Rates**
Residential	1,486,577,640	85.9%	7.959%	4.54%	0.00%	0.00%	0.00%	4.54%	11.36%	**15.90%**	15.90%
GS - XS,S	515,621,307	123.7%	0.042%	0.04%	0.00%	0.09%	-0.04%	0.09%	8.59%	**8.68%**	8.66%
GS - M	316,428,191	111.9%	4.042%	2.31%	-0.01%	0.09%	-0.17%	2.21%	7.66%	**9.86%**	9.87%
GS - L	293,386,250	100.5%	6.042%	3.45%	-0.01%	0.09%	-0.07%	3.45%	5.10%	**8.55%**	8.55%
GS - XL	203,076,401	87.0%	6.142%	3.50%	-0.01%	0.09%	0.00%	3.58%	4.71%	**8.28%**	8.28%
GS - schools	11,344,975	91.1%	6.042%	3.45%	-0.01%	0.09%	-2.33%	1.19%	9.35%	**10.54%**	10.54%
GS - worship	4,069,264	62.3%	9.042%	5.16%	-0.01%	0.09%	0.00%	5.23%	11.34%	**16.57%**	16.77%
Irrigation	28,739,440	93.7%	5.742%	3.28%	-0.01%	0.09%	0.00%	3.35%	11.30%	**14.65%**	14.66%
Lighting	29,660,294	94.6%	5.742%	3.28%	-0.01%	0.09%	0.00%	3.35%	4.37%	**7.71%**	7.71%
Total	2,888,903,762	95.0%	5.742%	3.28%				3.28%	9.28%	**12.55%**	**12.55%**

		Increase	Increase
residential	1,486,577,640	7.96%	4.54%
Non-res	1,402,326,122	3.40%	1.93%

Appendix M

aps

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all rate schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. Application for Service

Before supplying service APS will verify the identity of Applicant. Applicants may be required to appear at Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 Grounds for Refusal of Service - APS may refuse service if any of the following conditions exist:

(A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

(B) A condition exists that in Company's judgment is unsafe or hazardous.

(C) The Applicant has failed to meet APS's security-deposit requirements outlined in Section 3.

(D) The Applicant is known to be in violation of a Company Tariff.

(E) The Applicant fails to furnish the funds, service, equipment, rights-of-way or Easements required to serve the Applicant and that have been specified by APS as a condition for providing service.

(F) The Applicant falsifies his or her identity for the purpose of obtaining service.

(G) Service is already being provided at the address for which the Applicant is requesting service.

(H) Service is requested by an Applicant, and a prior Customer, who will reside at, or benefit from service at the premises, owes APS a delinquent bill for the same class of service, from the same or a prior service address.

(I) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

2. Service-Establishment Charges

A Service-Establishment Charge of $8.00 for residential or $33.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month.

2.1 Multiple Connects - If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service-Establishment Charge once for every two Delivery Points.

2.2 After-hours Charge -The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $8.00 for residential with standard metering, $137.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 Same-Day Connect Charge - The Customer must also pay a same-day connect charge of $87.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by Company, waive the same-day fee.

2.4 Non-Standard Service Request Charge -The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when Customer requests services that do not meet the definition of Service-Establishment as defined in A.A.C. R14-2-203.D.3 and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives used by APS to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 Waiving of Service Establishment Charge - Company may waive the Service-Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company.

aps

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

3. Establishing Credit, Security Deposits and other forms of Credit Assurance

When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to place a security deposit to secure payment of bills for service.

3.1 Residential Establishment of Credit - APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

(A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.

(B) Company receives an acceptable credit rating, as determined by Company, for the Applicant from a credit-rating agency used by Company.

(C) The Applicant can produce a letter regarding verification of credit from an electric utility where service of a comparable nature was last received within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.

(D) If in lieu of a security deposit, Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.

3.2 Nonresidential Establishment of Credit - All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

(A) The Applicant had service of a comparable nature with Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.

(B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 General Deposits Guidelines - If a security deposit is required, a separate deposit may be required for each service location.

(A) Customer's security deposits will not preclude Company from terminating an agreement for service or suspending service if Customer fails to meet service-agreement obligations.

(B) Company may choose to accept less than the full deposit required at time of service establishment based on Customer's financial condition.

(C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, Company may require Customer to establish or reestablish a security deposit.

3.4 Residential Security Deposits - Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 Nonresidential Security Deposits - Nonresidential security deposits will not exceed two and one-half times the Customer's maximum monthly billing as estimated by Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by Company based on the results of using a credit-scoring worksheet. Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 Deposit Interest - Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 Deposit Refunds - If the Customer terminates all service with Company, their security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days.

3.8 Residential security deposits or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

(A) Nonresidential security deposits and noncash deposits on file with Company will be reviewed after 24 months of service and will be returned if:

(1) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(2) Customer's financial condition does not warrant an extension of the security deposit.

4. Rates

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 Rate Selection - APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 Rate Information - APS will provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in Company Tariff affecting those Customers.

4.3 Optional Rates – Optional rate schedules are available for certain classes of service. After establishing service a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. No further rate schedule changes may be made within the succeeding 12 month period. If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

5. Billing

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at Company option.

5.1 Payment of Bills - The Customer is responsible for paying bills until service is ordered discontinued and Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services are involved, until Company has had reasonable time to process the disconnect request.

5.2 Failure to Receive Bills or Notices (including notices of disconnection) which have been properly placed in the United States mail or sent through alternative billing forms, such as electronic mail, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the customer of their obligations.

5.3 Incentive for Electronic Payments - A monthly incentive of $0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

5.4 Billing Errors - When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.

5.5 Corrected Charges for Overbilling - Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by Company.

5.6 Corrected Charges for Underbilling - Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and is not limited to three or six months as applicable.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with Customer to establish a payment plan that is acceptable to Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

5.7 Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. Collection Policy

The following collection policies apply to all Customer accounts:

6.1 Delinquent Bills - All bills rendered by Company are due and payable no later than 15 calendar days from the billing date. Any payment not received within this time frame are delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of Company's termination procedure.

Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.

6.2 Late Charges - All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 Transfer of Outstanding Bills - If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to Company, Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, Company has the right to collect the full amount owed from any one of the Customers.

6.4 Dishonored Payments - If Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The tender of a dishonored payment in no way relieves the Customer of the obligation to pay Company under the original terms of the bill, or defers the Company's right to terminate service for nonpayment of bills.

(C) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 Collection Agency Referrals - All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, Customer may be responsible for the associated collection-agency fees incurred.

7. Termination of Service

7.1 To avoid termination of service, the Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

APS may also require payment of Same-Day and After-Hours charges prior to restoring service

7.3 Termination of Service With Notice - APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if Company has met the notice requirements established by the Arizona Corporation Commission:

(A) Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.

(B) A Customer's failure to pay a Delinquent Bill for services provided by Company.

(C) The Customer's breach of a written contract for service.

(D) The Customer's failure to comply with Company's deposit requirements.

(E) The Customer's failure to provide Company with satisfactory and unassisted access to Company's equipment.

(F) When necessary to comply with an order of any governmental agency having jurisdiction.

(G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the premises.

(H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.

(I) Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

7.4 Termination of Service Without Notice - Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

(A) If Company observes, or has evidence of, a hazard to the health or safety of persons or property;

(B) If Company has evidence of Meter Tampering or fraud.

(C) If Company has evidence of unauthorized resale or use of electric service.

(D) The Customer fails to comply with the curtailment procedures imposed by Company during a supply shortage.

7.5 Termination of Service for Dishonored Payment - Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, or certified funds. If Customer has already received a notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

(A) When Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.

(B) When Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 Termination Process Charges - Company will require payment of a Field Call Charge of $10.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

8. Metering & Metering Equipment

8.1 Standard Metering - The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All customers will be served using the Company's standard metering equipment unless:

(A) the customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) the customer meets all eligibility requirements for non-standard metering and voluntarily requests non-standard metering.

8.2 Non-Standard Metering - The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to customers who select a non-standard meter.

8.3 Non-Standard Metering Eligibility - Only residential customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 Non-Standard Metering Charges -The following charges will apply when a customer voluntarily requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for customerswith existing AMI meter.

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 Discontinuation of Non-Standard Metering - The Company may replace a non-standard meter with a standard meter, without notifying the customer prior to replacement, under any of the following conditions:

(A) Company employees observe or have evidence of a safety hazard to employees, customers, or Company or customer property.

(B) Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) Company has evidence of unauthorized resale of electricity.

(D) Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to Company equipment, and physical threats such as weapons or dogs.

(E) All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 Measuring Customer Service - All energy sold to the Customer by Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 Meter Rereads – When requested by Customer, APS will reread the customer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 Meter Testing - APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon Customer request.

If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 Meter Test Charge - If the Meter is found to be within the plus or minus 3% limit, Company may charge the Customer $44.00 plus applicable adjustments for Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

8.10 Meter Tampering - If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by Company.

9. **Service Installations & Metering -** The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

   9.1 Customer Equipment - The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by Company. In circumstances where a clearance is not required by law, Company may require Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

   9.2 Special Meter-Reading Device - Where a Customer requests, and Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

   9.3 Totalized Metering and Billing - Company normally meters and bills each site separately. But, at Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at Company's option, be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

   9.4 Service Connections - Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

   (A) For overhead service, the Point of Delivery is where Company's service conductors terminate at the Customer's weatherhead or bus rider.

(B) For underground service, the Point of Delivery is where Company's service conductors terminate in the Customer's or development's service equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing Company's underground service conductors.

(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the Customer's service entrance conductors. APS employees must carry Company-issued identification that they will show on request.

10. Customer Obligations

10.1 Load Characteristics - The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customer must meet power factor requirements as specified in the applicable rate schedules.

10.2 Easements - All suitable Easements or rights-of-way required by Company for any portion of an extension to serve a Customer, which is either on sites owned, leased, or otherwise controlled by the Customer or developer, or other property required for the extension, will be furnished in Company's name by the Customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All Easements or rights-of-way granted to, or obtained on behalf of Company will contain terms and conditions that are acceptable to Company. When Company discovers that the Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, Company will notify the Customer or the Customer's agent and take whatever actions are necessary to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. Company will notify the Customer in writing of the violations.

10.3 Access for Repair, Maintenance and Service Restoration - Company's authorized agents must have satisfactory unassisted 24 hour a day, seven days a week access to Company's equipment located on Customer's sites for the purpose of repair, maintenance, and service-restoration work that Company may need to perform.

10.4 Access for Install, Inspect, Read, or Remove - Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all reasonable hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 Trip Charge - A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

10.6 Six Months No Access - If Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then Company has sufficient cause to terminate service or deny any rate options where, in Company's opinion, access is required.

10.7 Remedies - The remedy for unassisted access will be at APS's discretion and may include the installation by Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

11. Company Obligations

11.1 Customer-Specific Information - Customer-specific information will not be released without Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with Company if the goods or services will help Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to Company.

11.2 Service Voltage –Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. Limitations on Liability of Company

12.1 Service Interruptions - Company is not liable to the Customer for any damages caused by Load Serving Electric Service Provider's equipment or failure to perform, fluctuations, interruptions, or curtailment of electric service, except where caused by Company's willful misconduct or gross negligence.

(A) Company may, without incurring any liability, suspend the Customer's electric service for periods reasonably required to permit Company to accomplish repairs to, or changes in, any Company's facilities.

(B) The Customer is responsible for protecting Customer's own sensitive equipment from harm caused by variations or interruptions in power supply.

(C) If a national emergency or local disaster results in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other Customers to provide necessary service to civil-defense or other emergency-service agencies on a temporary basis until normal service to these agencies can be restored.

12.2 Use of Service or Apparatus - The Customer will save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or their use on the Customer's side of the Point of Delivery. Company has the right to suspend or terminate service if Company learns of service use by the Customer under hazardous conditions.

(A) The Customer will exercise all reasonable care to prevent loss or damage to Company property installed on the Customer's site for the purpose of supplying service to the Customer. The Customer is responsible for payment for loss or damage to Company property on the Customer's site arising from neglect, carelessness, or misuse, and will reimburse Company for the cost of necessary repairs or replacements.

(B) The Customer is responsible for payment of any equipment damage or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the Meter.

(C) The Customer is responsible for notifying APS of any failure in Company's equipment.

12.3 Removal of Facilities - Upon termination of service, Company may, without liability for injury or damage, dismantle and remove its facilities, installed for the purpose of supplying service to the Customer, and Company will have no further obligation to serve the Customer.

13. Successors and Assigns - Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by Company.

14. Warranty – There are no understanding, agreements, representations, or warranties , expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of Company in connection with sales and deliveries.

15. Direct Access Service – *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*

15.1 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

15.2 Direct Access Service - Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.

(A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.

(B) If a Customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer service.

(C) Unpaid charges incurred before the Customer selects Direct Access will not delay the Customer's request for Direct Access. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to Company under Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where Company is the MRSP, Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 Direct Access Deposits - If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that Company is providing bundled electric service.

15.4 Direct Access and Company Equipment

(A) Meters - A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment under Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) Lock-rings - Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace 10% of the issued keys within any 12 month period because of loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock-ring keys must be returned to Company within five working days if the MSP or its authorized agents are:

No longer permitted to remove Company Meters under the conditions of Company's Schedule 10;

(1)No longer authorized by the Arizona Corporation Commission to provide services; or

(2)The ESP Agreement has been terminated.

(C) Site Meetings - If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30 day intervals. [A.A.C. R14-2-201-(5)]

Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, and Christmas Day.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (15 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(12)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on Customer's property. [A.A.C. R-14-2-201-(13)]

Easement means a property owner ("Grantor") grants the right to use the owner's land to another party. An easement gives Company the right to have Company lines on property not owned by the Company. This allows Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity. The Grantor may continue to use the land along the easement within certain limitations.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not apply and service will automatically be transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(23)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(25)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(26)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(27)]

aps

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(31)]

Tariffs mean the documents filed with the Arizona Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products. [A.A.C. R14-2-201(42)]

Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$8.00	2
Nonresidential Service Establishment Charge	$33.00	2
After hours Charge -Residential Standard Metering	$8.00	2.2
After hours Charge -Residential Non-Standard Metering	$137.00	2.2
After hours Charge -Nonresidential	$164.00	2.2
Same Day Connect Charge	$87.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
Electronically Transmitted Payment Discount	-$0.48	5.3
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$10.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering- Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9

Trip Charge - Residential	$22.00	10.5
Trip Charge - Nonresidential	$26.00	10.5

Appendix N

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

General Description

This schedule establishes the Terms and Conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (APS or Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1 **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2 **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

1.3 **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.4 **Conversion** means converting overhead distribution facilities to underground facilities.

1.5 **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.

1.6 **Doubtful Permanency means** a customer who in the opinion of the Company is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.7 **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8 **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9 **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment installed solely to serve an individual applicant, or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system, as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10 **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11 **Irrigation** means water pumping service.

1.12 **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicants successors in interest with Company approval, which approval will not be unreasonably withheld.

1.13 **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.14 **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.15 **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.16 **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.17 **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.18 **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.19 **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.20 **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.

1.21 **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.22 **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.23 **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.24 **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed

1.25 **Rural Arizona Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.26 **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Rural Arizona Municipality, and where the Rural Arizona Municipality will be the lease-holder for future permanent applicants.

1.27 **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.28 **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.29 **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

2. General Provisions for Service

2.1 **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), "Temporary Applicants" (Section 13), and "Doubtful Permanency Customers" (Section 14).

2.2 **Schedule of Charges** -An applicant requesting an extension will be provided a sketch showing the Extension Facilities and an itemized cost quote based on the Schedule of Charges or other applicable details. The Schedule of Charges is attached to this Service Schedule as Attachment 1. When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Extension Facilities for General Service applicants with estimated demand loads of three megawatts or greater, or that require in aggregate 3,000 kVA of transformer capacity or greater.

(D) Extension Facilities that require three-phase transformer installations greater than the sizes noted in the Schedule of Charges.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.

2.3 **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all earth-work including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

(C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

(D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

2.4 **Refunds** – The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High Rise Development will be five years from the date Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family Developments will be five years and will start three months from the date Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

2.5 **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6 **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1 Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on a free footage basis under the following conditions:

(A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line

Extension Agreement is signed by the applicant.

(B) The site plan has been approved and recorded in the county having jurisdiction.

(C) The total footage of the Extension Facilities (primary, secondary, service) does not exceed 750 feet per applicant or $10,000; or

(D) The total cost of the Extension Facilities, as determined by Company, is less than $10,000 per applicant.

3.2 All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3 Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5 The footage allowance of 750 feet and the cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

3.6 Examples of the application of Section 3.1 can be found in Attachment 2 – Free Footage Illustrative Example.

4. Residential Subdivision Developments

4.1 Extension Facilities will be installed to Residential Subdivision Developments of four or more homes in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If final approved plat is different from what was originally submitted to Company it may cause delays and additional cost for redesign.

4.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3 A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4 In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of developer.

4.5 That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as street lights.

4.6 The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7 Examples of the application of Section 4 can be found in Attachment 3 - Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1 Extension Facilities will be installed to Residential "Lot Sale" Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

5.3 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

5.4 Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

5.5 Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1 Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2 The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate based on the scope of the project.

6.3 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

6.4 Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

7.1 Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost estimate depending on the scope of the project.

7.3 A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4 In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of applicant.

7.5 That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as street lights etc.

7.6 The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8 General Service Provisions

8.1 Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9 Basic General Service

9.1 Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2 The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3 The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity, will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

9.4 The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project-Specific Cost Estimates.

9.5 Economic Feasibility Analysis for Basic General Service Applicants - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(E) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10 High Rise Developments

10.1 Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS's Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2 The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate, and will be paid by the applicant before Company installing facilities.

10.3 Economic Feasibility Analysis for High Rise Developments - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4 Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

11 Mixed-Use Developments

11.1 Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2 The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate, and will be paid by the applicant before Company installing facilities.

11.3 Economic Feasibility Analysis for Mixed-Use Developments - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4 Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12 Corporate Business & Industrial Park Developments

12.1 Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2 The cost of installing Extension Facilities will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

12.3 The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity, will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

12.4 The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project-Specific Cost Estimates.

12.5 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

12.6 Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

12.7 Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13 Temporary Applicants

13.1 Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate.

13.2 A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3 When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14 Doubtful Permanency Customers

14.1 When, in the opinion of Company, Permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with the

Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

14.2 A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15 Municipalities and Other Governmental Agencies

15.1 Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2 The effective date for projects enacted under this provision for purposes of refunds (Section 2.4) will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16 Change in Applicant's Service Requirements

16.1 Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17 Relocations, Conversions and Upgrades of Company Facilities

17.1 **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction.

Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2 **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3 **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

18 Additional Primary Feed or Specialized Equipment

18.1 When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19 Unusual Circumstances

19.1 In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20 Abnormal Loads

20.1 Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as: transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21 Master Metering

21.1 **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion are individually metered by Company.

21.2 **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

21.3 **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4 **Conversion from Master Meter to Individually Metered System** - Company will convert its facilities from a master metered system to a Permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22 Voltage

22.1 All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2 Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right-of- way.

23 Point of Delivery

23.1 For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

23.2 For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.

23.3 For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

24 Easements

24.1 Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension, will be obtained by applicant and provided to Company in Company's name without cost to, or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25 Grade Modifications

25.1 If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26 Measurement and Location

26.1 Measurement must be along the proposed route of construction.

26.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

26.3 Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27 Agreements

27.1 **Study and Design Agreements** -Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.

27.2 **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement, or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension; otherwise the payment will be non-refundable.

27.3 **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28 Applicant Construction of Company Distribution Facilities

28.1 Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2 This option is not available for the following:
(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.
(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3 All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4 Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5 Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6 A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7 For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8 Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29 Settlement of Disputes

29.1 Any dispute between the applicant or prospective applicant and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30 Policy Exceptions

30.1 This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission. The following exceptions have been approved for Rural Municipality applicants:

(A) Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by Permanent applicants.

(B) The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

(C) The refund eligibility period for Rural Municipal Business Developments will be seven years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

(D) Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required seven years from the Execution Date of the agreement if the project has not become economically feasible by the end of the seven year refundable period. Any unrefunded advance balance paid at the start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction seven years from the Execution Date of the agreement.

(E) Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

(F) The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(G) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment 1
Schedule of Charges – Single Phase

APS Schedule 3 Rev 13, Line Extension Schedule of Charges

Single Phase	OH Primary	UG Primary				OH Secondary	UG Secondary	
	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Junction Cabinet	OH/UG Transition	Secondary Pole	OH/UG Secondary Transition	J Box
	$16.67	$5.64	$898	$3,889	$1,346	$2,259	$892.22	$105.55
	Each Installation							
Pole Interset	$10,251.54							
OVERHEAD Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$3,853	$6.15				
	200 Amp	50kVA	$4,178	$7.90				
	400 Amp	50kVA	$4,178	$7.90				
	600 Amp	75kVA	$5,249	$13.06				
	800 Amp	100kVA	$6,057	$18.23				
UNDERGROUND Single Phase	SES Size	Transformer Size, 120/240V		Service wire/Linear Ft				
	200 Amp	25kVA	$4,266	$5.22				
	200 Amp	50kVA	$4,657	$6.66				
	400 Amp	50kVA	$4,657	$6.66				
	600 Amp	75kVA	$5,229	$13.46				
	800 Amp	100kVA	$5,984	$14.91				

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.
3) Pad Mount Junction Cabinet is a single phase termination cabinet.
4) Primary OH cost per foot is for one phase and a neutral or two phases and no neutral; includes poles, framing, 2R conductor.
5) Charges for services are based on linear footage from Transformer to SES regardless of the number of sets. J Boxes not included in footage cost.
6) All footages to be calculated by linear footages.
7) Transition is from the OH line to the UG line: includes wire down pole and accessories. Pole NOT included.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment 1
Schedule of Charges – Three Phase

APS Schedule 3 Rev 13, Line Extension Schedule of Charges

	Overhead	Underground								
FEEDER Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (3-750)	Pull Box (3-750)	Manhole (3-750)	Cost per Circuit Foot (6-750)	Pull Box (6-750)	Manhole (6-750)	Pad Mount Switch Gear	Cost per Circuit Foot 1100A Cable (3-1100)	Cost per Circuit Foot 1100A Cable (6-1100)
	$29.31	$24.36	$4,694	$13,345	$48.08	$8,435	$19,144	$17,981	$27.63	$54.63
		Each Installation			Each Installation				Each Installation	Each Installation
OH/UG Transition		$6,566			$7,947				$6,603	$8,021
	Each Installation									
Pole Interset	$10,425.96									
	Overhead	Underground								
PRIMARY Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (3-1/0T)	Cost per Circuit Foot (3-4/0T)	Pull Box	Pad Mount Switch Gear					
	$22.18	$16.80	$19.91	$1,647	$17,981					
		Each Installation	Each Installation							
OH/UG Transition		$3,004	$3,100							
	Each Installation									
Pole Interset	$10,425.96									
	Overhead									
OVERHEAD Three Phase	SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft	
	200 Amp	3-25kVA	$9,047	$6.29		200 Amp	3-50kVA	$12,069	$6.29	
	200 Amp	3-50kVA	$10,422	$6.29						
	400 Amp	3-50kVA	$10,422	$8.19		400 Amp	3-75kVA	$14,064	$8.19	
	600 Amp	3-50kVA	$10,422	$10.42		600 Amp	3-100kVA	$15,939	$10.42	
	800/1000 Amp	3-75kVA	$13,619	$19.69		600 Amp	3-167kVA	$18,181	$10.42	
	Underground Pad mount									Transition
UNDERGROUND Three Phase	SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft	OH/UG Secondary Transition
	200 Amp	112.5kVA	$8,337	$7.12		200 Amp	112.5kVA	$11,080	$7.12	
						400 Amp	150kVA	$12,434	$12.71	
	400 Amp	112.5kVA	$8,337	$12.73		400 Amp	225kVA	$13,445	$12.71	$927.66
	600 Amp	150kVA	$12,495	$18.08		600 Amp	300kVA	$15,042	$22.86	
	800 Amp	225kVA	$13,907	$36.16		800 Amp	500kVA	$17,145	$36.09	
	1000 Amp	225kVA	$13,907	$36.16		1000 Amp	500kVA	$17,145	$36.09	
	1200 Amp	300kVA	$15,181	$36.16		1200 Amp	750kVA	$21,376	$54.01	
	1600 Amp	500kVA	$19,433	$72.04		1600 Amp	1000kVA	$24,378	$72.04	
	2000 Amp	500kVA	$19,438	$72.04		2000 Amp	1000kVA	$24,383	$72.04	
	2500 Amp	750kVA	$25,603	$126.10		2500 Amp	1500kVA	$34,903	$108.09	
	3000 Amp	750kVA	$25,613	$126.10		3000 Amp	1500KVA	$34,913	$108.09	
	3000 Amp	1000kVA	$30,638	$162.05		3000 Amp	2000kVA	$42,539	$162.05	

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.
3) For Multiple services out of one three phase transformer; the service cost will be determined by each SES and the transformer cost will be determined from the combined total of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000 amps.
4) Overhead feeder cost per foot is for 3/0 and above, including 477 & 795 conductors.
5) UG Primary circuit footage is 3 cables making up 3 phase; 2 circuits is parallel conductors.
6) Charges for services are based on linear footage from transformer to SES regardless for the number of sets.
7) Transition is from the OH line to the UG line: includes wire down pole and accessories. Pole NOT included.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment 2
Examples to Section 3* - Free Footage Illustrative Example

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 1	**500**	**$15.00**	**50**	**$ 4.89**	**550**	**$ 7,744.50**	**$ -**

APS $7,744.50** | Total 550' | Customer Payment $0

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 2	**620**	**$ 15.00**	**135**	**$ 4.89**	**755**	**$ 9,960.15**	**$ -**

APS $9,960.15** | Total 755' | Customer Payment $0

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 3	**675**	**$ 15.00**	**50**	**$ 4.89**	**725**	**$ 10,369.50**	**$ 369.50**

APS $10,000.00** | Total 725' | Customer Payment $369.50

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 4	**660**	**$ 15.00**	**90**	**$ 4.89**	**750**	**$ 10,340.10**	**$ 340.10**

APS $10,000.00** | Total 750' | Customer Payment $340.10

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 5	**700**	**$ 15.00**	**100**	**$ 4.89**	**800**	**$ 10,989.00**	**$ 989.00**

APS $10,000.00** | Total 800' | Customer Payment $989.00

*Scenarios do not reflect all components required for a complete project. **APS portion does not include cost of transformer.

Attachment 3
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Appendix O

Lost Fixed Cost Recovery
Plan of Administration

Effective Date: XXXX

Table of Contents

1. General Description

This document describes the plan of administration for the Lost Fixed Cost Recovery (LFCR) mechanism approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on XX/XX/XXX in Decision No. XXXXX. The LFCR mechanism provides for the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of energy efficiency (EE) savings and distributed generation (DG) determined to have occurred. Costs to be recovered through the LFCR include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution.

2. Definitions

Applicable Company Revenues - The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Current Period - The most recent adjustment year.

DG Savings - The amount of MWh sales reduced by DG. APS will use meter data to calculate DG system savings where available. Each year, APS will use actual data from January through September and forecast data for the remainder of the calendar year (October through December) to calculate the savings. The calculation of DG Savings will consist of the following by class:

a. Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.

b. Excluded MWh Production: The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

c. True-Up Prior Period: The reconciliation of APS's forecast data of DG sales reductions for the three months in the Prior Period to verified DG sales reductions in the Prior Period.

EE Programs - Any program approved in APS's annual implementation plan.

EE Savings - The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

a. Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.

b. Current Period: The annual EE related sales reductions (MWh). Each year, APS will use actual pre-MER verified data through November and forecast data for December to calculate annual savings.

c. Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules.

d. True-Up Prior Period: The reconciliation of APS's forecast data of annual EE sales reductions for the Prior Period to the MER verified EE sales reductions in the Prior Period.

Excluded Delivery Revenue - 50% of any delivery demand (kW) revenue as determined in Decision No. XXXXX and calculated on Schedules 6 and 7.

Excluded Rate Schedules - The LFCR mechanism will not apply to large general service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35, XHLF and E-36 XL, or to unmetered General Service customers under E-30 and lighting schedules, Contract 12.

LFCR Adjustment - Total Lost Fixed Cost Revenue as calculated on Schedule 2, divided by forecast retail kWh sales for the proposed adjustor period. For customers on a demand rate the adjustment will be applied as a kW charge. For customers on an energy only rate the adjustment will be applied as kWh charge. This adjustment will be applied to all customer bills, with the exception of those customers on Excluded Rate Schedules, or if the customer's current rate has alternate provisions.

Lost Fixed Cost Rate - A rate determined at the conclusion of APS's most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue - The amount of fixed costs not recovered by the utility because of EE and DG during the calendar year. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Prior Period - The 12 months preceding the Current Period.

Recoverable MWh Savings - The sum of EE Savings and DG Savings by rate class.

Transition Balance - The Lost Fixed Cost Revenue balance as calculated in compliance with the LFCR Plan of Administration applicable during that time period per Decision No. 73183 and modified in Decision No. 74202.

3. LFCR Annual Incremental Cap

The LFCR Adjustment will be subject to an annual 1% year-over-year cap based on Applicable Company Revenues. If the annual LFCR Adjustment results in a surcharge and the annual incremental increase exceeds 1% of Applicable Company Revenues, any amount in excess of the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance.

4. Historical Transition

Upon implementation of the revised LFCR Plan of Administration in Decision No. XXXXX, the Transition balance will be calculated on Schedule 4 (LFCR Historical Transition) and reported on Schedule 2 (LFCR Annual Incremental Cap Calculation).

5. Filing and Procedural Deadlines

APS will file the calculated LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by February 15th. The new LFCR Adjustment will not go into effect until approved by the Commission. If approved, the new rate will take effect with the first billing cycle in May, unless otherwise specified by the Commission.

6. Compliance Reports

APS will provide comprehensive Compliance Reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1: LFCR Annual Adjustment
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Historical Transition
- Schedule 5: LFCR Test Year Rate Calculation
- Schedule 6: Distribution Revenue Calculation - General Service
- Schedule 7: Distribution Revenue Calculation - Residential
- Schedule 8: Annual DG Installation Report

Schedules 1 through 8, attached hereto, will be submitted with APS's annual compliance filing.

Line No.	(A) Annual Percentage Adjustment	(B) Reference	(C) Total
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	$ -
2.	Applicable Company MWh		-
3.	$/kWh	Line 1 / Line 2	$ -
4.	Applicable Company MWh for customer billed demand		-
5.	$ for Customers Billed Demand	Line 3 * Line 4	$ -
6.	Applicable Company MW for customer billed demand		-
7.	$/kW	Line 5 / Line 6	$ -

Line No.	(A) **LFCR Annual Incremental Cap Calculation**	(B) **Reference**	(C) **Totals**
1.	Applicable Company Revenues		$ -
2.	Allowed Cap %		1.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$ -
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 33, Column C	$ -
4a	Historical Transition	Schedule 4, Line 33, Column C	$ -
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	-
6.	Annual Interest Rate		0.00%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 4a + Line 5 + Line 7)	$ -
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$ -
10a	Lost Fixed Cost Revenue - Billed[1]		$ -
10b	Rate Rider LFCR DG - Billed[1,2]		$ -
10c	Grid Access - Billed[1,2]		$ -
11.	LFCR Balancing Account	(Line 9 - Line 10)	$ -
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$ -
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$ -
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]	0.00%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$ -

[1] Amount billed to customers for the 12 calendar months of 20XX.
[2] Excludes amount billed to customers with DG installations prior to 2016.

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	(C) Totals	(D) Units
	Residential			
	Energy Efficiency Savings			
1.	Current Period		-	MWh
2.	Prior Period	Previous Filing, Schedule 3, Line 1, Column C	-	MWh
3.	Verified - Prior Period		-	MWh
4.	True-Up Prior Period	(Line 3 - Line 2)	-	MWh
5.	Cumulative Verified	(Previous Filing, Schedule 3, Line 5, Column C + Line 6)	-	MWh
6.	Total Recoverable EE Savings	(Line 1 + Line 4 + Line 5)	-	MWh
	Distributed Generation Savings			
7.	Current Period		-	MWh
8.	Prior Period	Previous Filing, Schedule 3, Line 7, Column C	-	MWh
9.	Verified - Prior Period		-	MWh
10.	True-Up Prior Period	(Line 9 - Line 8)	-	MWh
11.	Total Recoverable DG Savings	(Line 7 + Line 10)	-	MWh
12.	Total Recoverable MWh Savings	(Line 6 + Line 11)	-	MWh
13.	Residential - Lost Fixed Cost Rate	Schedule 5, Line 3, Column C	$ -	$/kWh
14.	Residential - Lost Fixed Cost Revenue	(Line 12 * Line 13)	$ -	
	C&I			
	Energy Efficiency Savings			
15.	Current Period		-	MWh
16.	Excluded MWh reduction		-	MWh
17.	Net - Current Period	(Line 15 - Line 16)	-	MWh
18.	Prior Period	Previous Filing, Schedule 3, Line 17, Column C	-	MWh
19.	Verified - Prior Period		-	MWh
20.	True-Up Prior Period	(Line 19 - Line 18)	-	MWh
21.	Cumulative Verified	(Previous Filing, Schedule 3, Line 21, Column C + Line 24)	-	MWh
22.	Total Recoverable EE Savings	(Line 17 + Line 20 + Line 21)	-	MWh
	Distributed Generation Savings			
23.	Current Period		-	MWh
24.	MWh DG Savings from Rate Schedules Excluded from LFCR		-	MWh
25.	Net - Current Period	(Line 23 - Line 24)	-	MWh
26.	Prior Period	Previous Filing, Schedule 3, Line 25, Column C	-	MWh
27.	Verified - Prior Period		-	MWh
28.	True-Up Prior Period	(Line 27 - Line 26)	-	MWh
29.	Total Recoverable DG Savings	(Line 25 + Line 28)	-	MWh
30.	Total Recoverable MWh Savings	(Line 22 + Line 29)	-	MWh
31.	C&I - Lost Fixed Cost Rate	Schedule 5, Line 6, Column C	$ -	$/kWh
32.	C&I - Lost Fixed Cost Revenue	(Line 30 * Line 31)	$ -	
33.	**Total Lost Fixed Cost Revenue**	**(Line 14 + Line 32)**	$ -	

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	(C) Totals	(D) Units
	Residential			
	Energy Efficiency Savings			
1.	Current Period		-	MWh
2.	Prior Period		-	MWh
3.	Verified - Prior Period		-	MWh
4.	True-Up Prior Period	(Line 3 - Line 2)	-	MWh
5.	Cumulative Verified		-	MWh
6.	Total Recoverable EE Savings	(Line 1 + Line 4 + Line 5)	-	MWh
	Distributed Generation Savings			
7.	Current Period		-	MWh
8.	Prior Period		-	MWh
9.	Verified - Prior Period		-	MWh
10.	True-Up Prior Period	(Line 9 - Line 8)	-	MWh
11.	Total Recoverable DG Savings	(Line 7 + Line 10)	-	MWh
12.	Total Recoverable MWh Savings	(Line 6 + Line 11)	-	MWh
13.	Residential - Lost Fixed Cost Rate	Decision No. 73183	$ 0.031111	$/kWh
14.	Residential - Lost Fixed Cost Revenue	(Line 12 * Line 13)	$ -	
	C&I			
	Energy Efficiency Savings			
15.	Current Period		-	MWh
16.	Excluded MWh reduction		-	MWh
17.	Net - Current Period	(Line 15 - Line 16)	-	MWh
18.	Prior Period		-	MWh
19.	Verified - Prior Period		-	MWh
20.	True-Up Prior Period	(Line 19 - Line 18)	-	MWh
21.	Cumulative Verified		-	MWh
22.	Total Recoverable EE Savings	(Line 17 + Line 20 + Line 21)	-	MWh
	Distributed Generation Savings			
23.	Current Period		-	MWh
24.	MWh DG Savings from Rate Schedules Excluded from LFCR		-	MWh
25.	Net - Current Period	(Line 23 - Line 24)	-	MWh
26.	Prior Period		-	MWh
27.	Verified - Prior Period		-	MWh
28.	True-Up Prior Period	(Line 27 - Line 26)	-	MWh
29.	Total Recoverable DG Savings	(Line 25 + Line 28)	-	MWh
30.	Total Recoverable MWh Savings	(Line 22 + Line 29)	-	MWh
31.	C&I - Lost Fixed Cost Rate	Decision No. 73183	$ 0.023190	$/kWh
32.	C&I - Lost Fixed Cost Revenue	(Line 30 * Line 31)	$ -	
33.	**Total Lost Fixed Cost Revenue**	**(Line 14 + Line 32)**	$ -	

Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference	(C) Total
	Residential Customers		
1.	Residential Fixed Revenue	Schedule 7, Line 18, Column G	$ -
2.	MWh Billed	Schedule 7, Line 17, Column B / 1,000	-
3.	Lost Fixed Cost Rate	(Line 1 / Line 2)	$ -
	C & I Customers		
4.	Total Fixed Revenue	Schedule 6, Line 18, Column G	$ -
5.	MWh Billed	Schedule 6, Line 17, Column B / 1,000	-
6.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$ -

Line No.	Rate Schedule (A)	Tariff Component (B)	Adjusted Test Year Billing Determinants (C)	Units (D)	Delivery Charge (E)	Demand Stability Factor (F)	(G) C*E*(1-F) Total Distribution Revenue
1	General Service Rate X						
2			-	kW	$ -	50%	$ -
3			-	kWh	$ -	0%	$ -
4	Sub Total		-	kW			$ -
5			-	kWh			$ -
6	General Service Rate X						
7			-	kW	$ -	50%	$ -
8			-	kWh	$ -	0%	$ -
9	Sub Total		-	kW			$ -
10			-	kWh			$ -
11	General Service Rate X						
12			-	kW	$ -	50%	$ -
13			-	kWh	$ -	0%	$ -
14	Sub Total		-	kW			$ -
15			-	kWh			$ -
16	Total kW		-	kW			$ -
17	Total kWh		-	kWh			$ -
18	Total						$ -

	(A)		(B)	(C)	(D)	(E)	(F)	(G)
								C*E*(1-F)
Line No.	**Rate Schedule**		**Tariff Component**	**Adjusted Test Year Billing Determinants**	**Units**	**Delivery Charge**	**Demand Stability Factor**	**Total Distribution Revenue**
1.	Residential Rate X							
2.				-	kW	$ -	50%	$ -
3.				-	kWh	$ -	0%	$ -
4.		**Sub Total**		-	**kW**			$ -
5.				-	**kWh**			$ -
6.	Residential Rate X							
7.				-	kW	$ -	50%	$ -
8.				-	kWh	$ -	0%	$ -
9.		**Sub Total**		-	**kW**			$ -
10.				-	**kWh**			$ -
11.	Residential Rate X							
12.				-	kW	$ -	50%	$ -
13.				-	kWh	$ -	0%	$ -
14.		**Sub Total**		-	**kW**			$ -
15.				-	**kWh**			$ -
16.	Total kW			-	**kW**			$ -
17.	Total kWh			-	**kWh**			$ -
18.	Total							$ -

Annual DG Statistics

	20XX	Cummulative beginning 2016
Total Number of Installation		
<5kW		
5kW to 6.5kW		
6.5kW to 10kW		
> 10kW		
Total Installed kW		

Appendix P

Environmental Improvement Surcharge
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Environmental Improvement Surcharge (EIS) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on [insert date] in Decision No. XXXXX. The EIS provides for the recovery of the capital carrying costs effect of actual environmental investments made by APS and not already recovered in base rates approved in Decision No. XXXXX or recovered through another Commission approved adjustment. The EIS will be calculated annually based on the EIS Qualified Investments closed to plant-in-service during the preceding calendar year.

2. Definitions

<u>Annual EIS Adjustment</u> - The Annual EIS Adjustment represents the EIS Capital Carrying Costs on the Qualified Net Plant to be recovered in the subsequent twelve month period and is assessed to customer bills via the EIS $/kWh rate.

<u>EIS Capital Carrying Costs</u> - EIS Capital Carrying Costs consists of (1) Return on the Qualified Net Plant calculated based on the Company's Weighted Average Cost of Capital (WACC) approved by the Commission in Decision No. XXXXX plus a return on the fair value increment (if any) for the Qualified Net Plant; (2) depreciation expense; (3) income taxes; (4) property taxes and (5) associated operations and maintenance expenses (O&M).

<u>EIS Qualified Investments</u> - Investments in Qualified Environmental Improvement Projects. Each EIS Qualified Investment must: (1) be classified in one or more of the FERC plant accounts as listed in Section 3 of this document, or any other successor FERC account, upon going into service and (2) be tracked by a specific project number.

<u>Fair Value Increment</u> - For purposes of the EIS, the difference between the Fair Value of the EIS Qualified Investments and Qualified Net Plant shall be deemed to be zero.

<u>Qualified Environmental Improvement Projects</u> - Projects designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. These standards and criteria for water, waste, and air include but are not limited to limits for carbon dioxide (CO_2), sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile

organic compounds (VOC), and toxics such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts.

Qualified Net Plant - The Qualified Net Plant consists of the EIS Qualified Investments and their associated accumulated depreciation, accumulated deferred income taxes, tax credits and in the event of federal corporate tax reform any related unamortized excess deferred taxes, where applicable.

Total kWh Sales - The total prior calendar year energy (kWh) sales served under applicable ACC jurisdictional electric rate schedules, except Rate Schedules E-36 XL and AG-X as reported in the Company's FERC Form No. 1.

3. Qualified FERC Accounts

1. Steam Production
    - FERC Account 310 - Land and Land Rights
    - FERC Account 311 - Structures and Improvements
    - FERC Account 312 - Boiler Plant Equipment
    - FERC Account 313 - Engines and Engine-Driven Generators
    - FERC Account 314 - Turbogenerator Units
    - FERC Account 315 - Accessory Electric Equipment
    - FERC Account 316 - Miscellaneous Power Plant Equipment

2. Nuclear Production
    - FERC Account 320 - Land and Land Rights
    - FERC Account 321 - Structures and Improvements
    - FERC Account 322 - Reactor Plant Equipment
    - FERC Account 323 - Turbogenerator Units
    - FERC Account 324 - Accessory Electric Equipment
    - FERC Account 325 - Miscellaneous Power Plant Equipment

3. Other Production
    - FERC Account 340 - Land and Land Rights
    - FERC Account 341 - Structures and Improvements
    - FERC Account 342 - Fuel Holders, Products, and Accessories
    - FERC Account 343 - Prime Movers
    - FERC Account 344 - Generators
    - FERC Account 345 - Accessory Electric Equipment
    - FERC Account 346 - Miscellaneous Power Plant Equipment

Please note this list may expand to include other accounts approved by the ACC in the future.

4. Calculation of Annual EIS Adjustment

The Annual EIS Adjustment is calculated utilizing the accumulation of Qualified Net Plant and calculated EIS Capital Carrying Costs, as defined above and is applied to applicable customers' total bill via a $/kWh rate over the twelve month period beginning in April of the year following the filing described in Section 6. below. The EIS $/kWh rate is calculated by dividing the

Annual EIS Adjustment by Total kWh Sales as determined in Schedule 3 of the filing. The EIS rate will not exceed $0.00050 per kWh.

5. EIS Balancing Account

APS will maintain accounting records that accumulate the difference between the actual allowable Annual EIS Adjustment as compared to the actual revenues received by the Company through the EIS surcharge during the recovery period (April through March). The difference will be recorded to the EIS Balancing Account each month and will be provided annually in Schedule 3 of the filing. In the event that Annual EIS Adjustments are more or less than the revenues collected as of the last billing cycle of March, the over or under collection will be subtracted from or added to the EIS calculation in the subsequent period subject to the overall cap of $0.00050 per kWh.

6. Filing and Procedural Deadlines

EIS Qualified Projects and the Annual EIS Adjustment calculation will be submitted by the Company to the ACC in the form of Schedules 1 through 3 as attached to this document and described in Section 7. *Compliance Reports*. APS will file the calculated EIS $/kWh rate including all supporting data, with the Commission for the previous year on or before February 1st.

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

7. Compliance Reports

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

Schedule 1: Qualified Investments for EIS Electric Plant in Service
Schedule 2: Annual EIS Adjustment Calculation
Schedule 3: Current Year EIS Cap Calculation and Adjustment

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1 - EIS
QUALIFIED INVESTMENTS
ELECTRIC PLANT IN SERVICE
FOR CALENDAR YEARS 20XX - 20XX

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
Totals					$ -

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2 - EIS
ANNUAL EIS ADJUSTMENT CALCULATION
PLANT IN SERVICE CALENDAR YEARS 20XX-20XX
BILLING PERIOD 4/1/20XX - 3/30/20XX
(Thousands of Dollars)

Line No.	(A) Annual EIS Adjustment Calculation	(B) Reference	(C) Totals
Qualified Plant			
1.	Qualified Environmental Improvement Projects	Schedule 1, Total Line, Column F	$ -
2.	Accumulated Depreciation		-
3.	Cumulative Deferred Tax/Tax Credits/Excess Deferred Taxes[1]		-
4.	Qualified Net Plant	Line 1 - Line 2 - Line 3	$ -
5.	Pre-tax Weighted Average Cost of Capital	Decision No. XXXXX	0.0000%
Capital Carrying Cost			
6.	Composite Return on EIS Net Plant	Line 4 * Line 5	$ -
7.	Annual Depreciation of Plant In Service		-
8.	Applicable Property Tax		-
9.	Associated O&M Expense		-
10.	Total Annual EIS Adjustment	Line 6 + Line 7 + Line 8 + Line 9	$ -

[1] In the event of a Federal Corporate Tax Rate Change

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3 - EIS

CURRENT YEAR EIS CAP CALCULATION AND ADJUSTMENT
PLANT IN SERVICE CALENDAR YEARS 20XX-20XX
BILLING PERIOD 4/1/20XX - 3/30/20XX
(Thousands of Dollars)

Line No.	(A) EIS Rate Calculation	(B) Reference		(C) Totals
1.	EIS Adjustment Prior Year	Previous Filing Schedule 2, Line 10	$	-
2.	EIS Revenue Billed Prior Year			-
3.	EIS Balancing Account	Line 1 - Line 2	$	-
4.	Current Year Annual EIS Adjustment	Schedule 2, Line 10	$	-
5.	Total Current Year Annual EIS Adjustment	Line 3 + Line 4	$	-
6.	Applicable Company Sales, excluding E-36XL and AG-X (kWhs)	FERC Form 1		-
7.	EIS Rate ($/kWh)	Line 5 / Line 6	$	-
8.	EIS Rate Cap ($/kWh)		$	0.00050
9.	EIS $ per kWh Rate Applied to Customer's Bills ($/kWh)	(Lesser of Line 7 and Line 8)	$	-

Appendix Q

Transmission Cost Adjustment
Plan of Administration

Table of Contents

1. General Description

The purpose of the Transmission Cost Adjustment (TCA) is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission (FERC) and at the same time as new transmission rates become effective for Arizona Public Service (APS or Company) wholesale customers. APS shall file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC information filing of its annual update of transmission service rates pursuant to its Open Access Transmission Tariff (OATT). This notice shall be filed with the Commission at the same time that APS makes its FERC filing.

The TCA applies to APS's Retail Electric Rate Schedules. For Standard Offer customers, the TCA is applied to the bill as a monthly kWh charge for Residential Service Customers and General Service Customers less than or equal to 20 kW. For all other Standard Offer customers, the TCA is applied to the bill as a monthly kW charge. The charge and modifications to it will take effect in billing cycle 1 of the June revenue month without proration.

APS's Network Integration Transmission Service (NITS) is calculated and filed annually with the FERC in accordance with APS's formula rate. The formula rate calculation is specified within the Company's OATT as filed and approved by the FERC.

2. Calculations

The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC Informational Filing of its Annual Update of transmission service. NITS rates as determined for the following classes:

Residential Service Customers
General Service Customers less than or equal to 20 kW
General Service Customers over 20 kW and less than 3 MW
General Service Customers equal to and greater than 3 MW

In addition to NITS, APS charges retail customers for other transmission services in accordance with its OATT. These additional ancillary services include:

Schedule 1 - Scheduling, System Control and Dispatch Service
Schedule 3 - Regulation and Frequency Response Service
Schedule 4 - Energy Imbalance Service

Schedule 5 - Operating Reserve-Spinning Reserve Service
Schedule 6 - Operating Reserve – Supplemental Reserve Service

APS's NITS rates will change annually, where ancillary service charges will change only through a separate filing when made by the Company to FERC.

The total APS OATT rate is the sum of the rates for providing these services. The revenue requirement resulting from the FERC APS OATT rate are collected by APS from its retail customers, partly in base rates and the remaining through the TCA rate.

3. TCA Balancing Account

APS will maintain accounting records that accumulate the difference in revenues anticipated to be recovered by the TCA, as compared to the actual revenues received by the Company through the TCA during the recovery period (June through May). The difference will be recorded to the TCA Balancing Account each month and will be provided annually in Attachment C of the filing. In the event the actual TCA revenues for the recovery period (June through the last billing cycle of May) are more or less than the anticipated revenues for that same period, the over or under collection will be subtracted from or added to the TCA balancing account calculation for the subsequent period.

4. Filing and Procedural Deadlines

APS will file the calculated TCA rates with the Commission each year no later than May 15th, in the form of Attachments A through H as attached to this document and described in Section 5. *Compliance Reports.*

The Commission Staff and interested parties shall have the opportunity to review APS's FERC Informational Filing of its Annual Update of transmission service rates pursuant to the APS OATT Attachment H-2, Formula Rate Implementation Protocols. The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC filing. The new TCA rates proposed by APS will go into effect with the first billing cycle in June (without proration), unless Staff requests Commission review or otherwise ordered by the Commission, and will remain in effect for the following 12-month period.

5. Compliance Reports

APS will provide an annual report to Staff detailing all calculations related to the calculated TCA rates. The reports will include the following Attachments A through H as attached to this document:

Attachment A:	Non-redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment B:	Redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment C:	Numerical inputs used to develop the new TCA-1 rates
Attachment D:	Estimated monthly bill impacts of the new TCA-1 rates
Attachment E:	Table illustrating the percentage demand of each of the classes for the 20XX OATT and 20XX OATT as filed with FERC

Attachment F:	Table illustrating the transmission cost embedded in base rates, the current and proposed TCA rates, and the differences in the current and new rates
Attachment G:	Actual and estimated transmission additions, dollars and estimated O&M for calendar years 20XX through 20XX (1 year actual and 2 years forecast)
Attachment H:	APS's Annual Update of transmission service rates pursuant to the APS OATT as filed with FERC

Attachment A

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail electric schedules. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include a transmission component of base rates that was originally established at $0.00000 per kilowatt-hour in accordance with A.C.C. Decision No. 67744. Decision No. 67744 also established the TCA. Decision No. 69663 modified the collection of transmission costs in retail rates to tie to the costs found in the FERC approved Open Access Transmission Tariff.

RATE

The charge shall be applied as follows:

Customer Class	**TCA Charge**
Residential	$0.000000/kWh
General Service 20 kW or less	$0.000000/kWh
General Service over 20 kW, under 3,000 kW	$0.000/kW
General Service 3,000 kW and over	$0.000/kW

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail electric schedules. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include a transmission component of base rates that was originally established at $0.00000 per kilowatt-hour in accordance with A.C.C. Decision No. 67744. Decision No. 67744 also established the TCA. Decision No. 69663 modified the collection of transmission costs in retail rates to tie to the costs found in the FERC approved Open Access Transmission Tariff.

RATE

The charge shall be applied as follows:

Customer Class	**TCA Charge**
Residential	$0.000000/kWh
General Service 20 kW or less	$0.000000/kWh
General Service over 20 kW, under 3,000 kW	$0.000/kW
General Service 3,000 kW and over	$0.000/kW

Attachment C

TCA Rate Calculation - Plan of Administration

Line	Service Type Retail Transmission Rates	Residential $/kWh (A)	GS≤20 kW $/kWh (B)	GS > 20 kW and < 3MW $/kW (C)	GS≥3 MW $/kW (D)
1.	NITS (A)	0.000000	0.000000	0.000	0.000
2.	Scheduling (B)	0.000000	0.000000	0.000	0.000
3.	Regulation & Frequency (B)	0.000000	0.000000	0.000	0.000
4.	Spinning Reserve (B)	0.000000	0.000000	0.000	0.000
5.	Operating Reserve (B)	0.000000	0.000000	0.000	0.000
6.	Energy Imbalance (B)	0.000000	0.000000	0.000	0.000
7.	Total (Lines 1 thru 7)	0.000000	0.000000	0.000	0.000
8.	Included In Retail Base Rates (C)	0.000000	0.000000	0.000	0.000
9.	Balancing Account (D)	0.000000	0.000000	0.000	0.000
10.	TCA (Line 7 - Line 8 + Line 9) (E)	0.000000	0.000000	0.000	0.000

(A) Source: Attachment H, Appendix A of Attachment H-1, Lines 161-164 - (APS's FERC Formula Rate Annual Update of transmission service rates pursuant to the APS OATT)

(B) Source: Ancillary Services as defined in Schedule 11 of the APS OATT

(C) Source: Base Transmission Rates as approved in Decision No. XXXXX

(D) Source: TCA Balancing Account Workpaper Detail (to be provided with TCA filing)

(E) Amounts presented in Attachment A and Attachment B

Attachment D

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of TCA Reset June 20XX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Residential (Avg - All Rates)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Residential (Rate E-12)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Commercial XS (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Attachment D

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of TCA Reset June 20XX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Commercial S (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-				-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Commercial - M (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Commercial - L (E-32)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Attachment D

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of TCA Reset June 20XX

	AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
	Current	Proposed			Current	Proposed	Current	Proposed
Industrial - XL (E-34,35)	Average Monthly Bill [1]	Average Monthly Bill [1,2]	$ Impact	% Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	-	-			-	-	-	-
Averge kW per Month	-				-	-	-	-
Base Rates	$ -	$ -			$ -	$ -	$ -	$ -
PSA	$ -	$ -			$ -	$ -	$ -	$ -
TCA	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
RES	$ -	$ -			$ -	$ -	$ -	$ -
DSMAC	$ -	$ -			$ -	$ -	$ -	$ -
EIS	$ -	$ -			$ -	$ -	$ -	$ -
SBA-2	$ -	$ -			$ -	$ -	$ -	$ -
Four Corners	$ -	$ -			$ -	$ -	$ -	$ -
LFCR	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	0.00%	$ -	$ -	$ -	$ -

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. All Adjustor levels in effect as of May 15, 20XX.
(2) Bill includes the projected impact to customers of the reset TCA adjustor.

Attachment E

Class Coincident Peak Demand

Class	20XX		20XX	
	MW	% of Coincident Demand	MW	% of Coincident Demand
Residential	0000.0	0.00%	0000.0	0.00%
General Service < 3MW	0000.0	0.00%	0000.0	0.00%
General Service > 3 MW	0000.0	0.00%	0000.0	0.00%
Total	0000.0	0.00%	0000.0	0.00%

Attachment F

Transmission Rates Embedded in Base Rates and TCA

Customer Group	Embedded Base Rate	Current TCA Rate	Proposed TCA Rate	Difference	Percentage Difference	
					TCA Rate	Total
	(A)	(B)	(C)	(D) = (C) - (B)	(E) = (D)/(B)	(F) = (D)/[(A)+(B)]
Residential	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	0.0%	0.0%
General Service 20 kW or less	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	$ 0.000000 /kWh	0.0%	0.0%
General Service over 20 kW and under 3,000 kW	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	0.0%	0.0%
General Service 3,000 kW and over	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	$ 0.0000 /kW	0.0%	0.0%

ATTACHMENT G

Arizona Public Service Company
20XX Transmission Actual Addition Dollars and O&M

Line No.	Funding Project	WA#	Description	Actual Cost	Purpose	Miles	Estimated O&M	In-Service Date
1							-	
2							-	
3							-	
4							-	
5							-	
6							-	
7							-	
8							-	
9							-	
10							-	
11							-	
12							-	
13							-	
14							-	
15							-	
16							-	
17							-	
18							-	
19							-	
20							-	
21							-	
22							-	
23							-	
24							-	
25							-	
26							-	
27							-	
28							-	
29							-	
30							-	
31							-	
32							-	
			Work Orders > $250k	-			$ -	
			Work Orders < $250K	-				
			Total	-				

ATTACHMENT G

Arizona Public Service Company
20XX Transmission Estimated Addition Dollars and O&M

Line #	Funding Project	WA#	Description	Total Estimate	Purpose	Miles	Estimated O&M	Estimated In-Service Date
1							-	
2							-	
3							-	
4							-	
5							-	
6							-	
7							-	
8							-	
9							-	
10							-	
11							-	
12							-	
13							-	
14							-	
15							-	
16							-	
17							-	
18							-	
19							-	
20							-	
21							-	
22							-	
23							-	
24							-	
25							-	
26							-	
27							-	
28							-	
29							-	
30							-	
31							-	
32							-	
			Work Orders > $250k	-			$ -	
			Work Orders < $250K	-				
			Total $	-				

ATTACHMENT G

Arizona Public Service Company
20XX Transmission Estimated Addition Dollars and O&M

Line #	Funding Project	WA#	Description	Total Estimate	Purpose	Miles	Estimated O&M	Estimated In-Service Date
1							-	
2							-	
3							-	
4							-	
5							-	
6							-	
7							-	
8							-	
9							-	
10							-	
11							-	
12							-	
13							-	
14							-	
15							-	
16							-	
17							-	
18							-	
19							-	
20							-	
21							-	
22							-	
23							-	
24							-	
25							-	
26							-	
27							-	
28							-	
29							-	
30							-	
31							-	
32							-	
			Work Orders > $250k	-			$ -	
			Work Orders < $250K	-				
			Total $	-				

Attachment H

Arizona Public Service Company

Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction	YEAR
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	0
2	Total Wages Expense		p354.28b	0
3	Less A&G Wages Expense		p354.27b	0
4	Total		(Line 2 - 3)	0
5	**Wages & Salary Allocator**		(Line 1 / 4)	**0.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	0
7	Total Plant In Service		(Sum Line 6)	0
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	0
9	Total Accumulated Depreciation		(Line 8)	0
10	Net Plant		(Line 7 - 9)	0
11	Transmission Gross Plant		(Line 22 - Line 38)	0
12	**Gross Plant Allocator**		(Line 11 / 7)	**0.0000%**
13	Transmission Net Plant		(Line 32 - Line 38)	0
14	**Net Plant Allocator**		(Line 13 / 10)	**0.0000%**
	Plant Calculations			
	Plant In Service (Note O)			
15	Transmission Plant In Service	(Note B)	Attachment 5	0
16	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	0
17	**Total Transmission Plant In Service**		(Line 15 + 16)	**0**
18	General & Intangible		Attachment 5	0
19	Total General		(Line18)	0
20	Wage & Salary Allocation Factor		(Line 5)	0.00000%
21	**General Plant Allocated to Transmission**		(19 * 20)	**0**
22	**TOTAL Plant In Service**		**(Line 17 + 21)**	**0**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	0
24	Accumulated Depreciation for Transmission Plant Additions for Current Rate Year		Attachment 6	0
25	**Total Transmission Accumulated Depreciation**		(Line 23 + Line 24)	0
26	Accumulated General Depreciation		Attachment 5	0
27	Accumulated Intangible Depreciation		Attachment 5	0
28	Total Accumulated Depreciation		(Sum Lines 26 to 27)	0
29	Wage & Salary Allocation Factor		(Line 5)	0.0000%
30	**General Allocated to Transmission**		(Line 28 * 29)	**0**
31	**TOTAL Accumulated Depreciation**		**(Line 25 + 30)**	**0**
32	**TOTAL Net Property, Plant & Equipment**		**(Line 22 - 31)**	**0**

Attachment H

Line	Description	Note	Source		Amount
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
33	ADIT net of FASB 106 and 109		Attachment 1		0
34	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 33)		**0**
	Transmission O&M Reserves				
35	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5		**0**
	Prepayments				
36	Prepayments	(Note A)	Attachment 5		0
37	**Total Prepayments Allocated to Transmission**		(Line 36)		**0**
38	**Land Held for Future Use**	(Note C)	p214		**0**
	Materials and Supplies				
39	Undistributed Stores Exp	(Note A)	p227.6c & 16.c		0
40	Wage & Salary Allocation Factor		(Line 5)		0.0000%
41	Total Transmission Allocated		(Line 39 * 40)		0
42	Transmission Materials & Supplies		p227.8c		0
43	**Total Materials & Supplies Allocated to Transmission**		(Line 41 + 42)		**0**
	Cash Working Capital				
44	Operation & Maintenance Expense		(Line 72)		0
45	Zero Cash Working Capital		Zero		0.0%
46	**Total Cash Working Capital Allocated to Transmission**		(Line 44 * 45)		**0**
	Network Credits				
47	Outstanding Network Credits	(Note N)	Attachment 5		0
48	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5		0
49	Net Outstanding Credits		(Line 47 - 48)		**0**
50	**TOTAL Adjustment to Rate Base**		(Line 34 + 35 + 37 + 38 + 43 + 46 - 49)		**0**
51	**Rate Base**		(Line 32 + 50)		**0**
	O&M				
	Transmission O&M				
52	Transmission O&M		p321.112.b		0
53	Less Account 565		p321.96.b		0
54	**Transmission O&M**		(Line 52 - 53)		**0**
	Allocated General Expenses				
55	Total A&G		p323.197.b		0
56	Less PBOP Adjustment		Attachment 5		0
57	Less Property Insurance Account 924		p323.185b		0
58	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b		0
59	Less General Advertising Exp Account 930.1		p323.191b		0
60	Less EPRI Dues	(Note D)	p352-353		0
61	**General Expenses**		(Line 55) - Sum (56 to 60)		0
62	Wage & Salary Allocation Factor		(Line 5)		0.0000%
63	**General Expenses Allocated to Transmission**		(Line 61 * 62)		**0**
	Directly Assigned A&G				
64	Regulatory Commission Exp Account 928	(Note G)	Attachment 5		0
65	General Advertising Exp Account 930.1	(Note K)	Attachment 5		0
66	Subtotal - Transmission Related		(Line 64 + 65)		**0**
67	Property Insurance Account 924		p323.185b		0
68	General Advertising Exp Account 930.1	(Note F)	Attatchment 5		0
69	Total		(Line 67 + 68)		0
70	Net Plant Allocation Factor		(Line 14)		0.0000%
71	**A&G Directly Assigned to Transmission**		(Line 69 * 70)		**0**
72	**Total Transmission O&M**		**(Line 54 + 63 + 66 + 71)**		**0**
	Depreciation & Amortization Expense				
	Depreciation Expense (Note P)				
73	Transmission Depreciation Expense		p336.7f		0
74	New plant Depreciation Expense		Attachment 6		0
75	**Total Transmission Depreciation Expense**		(Line 73 + Line 74)		**0**
76	General Depreciation		p336.10f		0
77	Intangible Amortization	(Note A)	p336.1f		0
78	Total		(Line 76 + 77)		0
79	Wage & Salary Allocation Factor		(Line 5)		0.0000%
80	**General Depreciation Allocated to Transmission**		(Line 78 * 79)		**0**
81	**Total Transmission Depreciation & Amortization**		**(Line 75 + 80)**		**0**

Attachment H

	Taxes Other than Income			
82	**Taxes Other than Income**		Attachment 2	0
83	**Total Taxes Other than Income**		**(Line 82)**	0
	Return / Capitalization Calculations			
	Long Term Interest			
84	Long Term Interest		p117.62c through 67c	0
85	**Long Term Interest**		(Line 84)	0
86	**Preferred Dividends**	enter positive	p118.29c	0
	Common Stock			
87	Proprietary Capital		p112.16c	0
88	Less Preferred Stock	enter negative	(Line 96)	0
89	Less Accumulated Other Comprehensive Income Account 219	enter negative	p112.15c	0
90	Less Account 216.1	enter negative	p112.12c	0
91	**Common Stock**		(Sum Lines 87 to 90)	0
	Capitalization			
92	Long Term Debt		p112.18c through 23c	0
93	Less Loss on Reacquired Debt	enter negative	p111.81c	0
94	Plus Gain on Reacquired Debt	enter positive	p113.61c	0
95	Total Long Term Debt		(Sum Lines 92 to 94)	0
96	Preferred Stock		p112.3c	0
97	Common Stock		(Line 91)	0
98	**Total Capitalization**		(Sum Lines 95 to 97)	0
99	Debt %		(Line 95 / 98)	0%
100	Preferred %		(Line 96 / 98)	0%
101	Common %		(Line 97 / 98)	0%
102	Debt Cost		(Line 85 / 95)	0.0000
103	Preferred Cost		(Line 86 / 96)	0.0000
104	Common Cost	(Note J)	Fixed	0.1075
105	Weighted Cost of Debt		(Line 99 * 102)	0.0000
106	Weighted Cost of Preferred		(Line 100 * 103)	0.0000
107	Weighted Cost of Common		(Line 101 * 104)	0.0000
108	**Total Return (R)**		(Sum Lines 105 to 107)	**0.0000**
109	**Investment Return = Rate Base * Rate of Return**		**(Line 51 * 108)**	**0**
	Composite Income Taxes			
	Income Tax Rates			
110	FIT=Federal Income Tax Rate			0.00%
111	SIT=State Income Tax Rate or Composite	(Note I)		0.00%
112	p		FIT deductible for SIT	0.00%
113	T = 1-{[(1-SIT) * (1-FIT)]/(1-SIT * FIT * p)}			0.00%
114	T/ (1-T)			0.00%
	ITC Adjustment	(Note I)		
115	Amortized Investment Tax Credit	enter negative	p266.8f	0
116	T/(1-T)		(Line 114)	0.00%
117	Net Plant Allocation Factor		(Line 14)	0.0000%
118	**ITC Adjustment Allocated to Transmission**		(Line 115 * (1 + 116) * 117)	**0**
119	**Income Tax Component =**		[Line 114 * 109 * (1-(105 / 108))]	-
120	**Total Income Taxes**		**(Line 118 + 119)**	-
	REVENUE REQUIREMENT			
	Summary			
121	Net Property, Plant & Equipment		(Line 32)	0
122	Adjustment to Rate Base		(Line 50)	0
123	**Rate Base**		(Line 51)	**0**
124	O&M		(Line 72)	0
125	Depreciation & Amortization		(Line 81)	0
126	Taxes Other than Income		(Line 83)	0
127	Investment Return		(Line 109)	0
128	Income Taxes		(Line 120)	0
129	**Gross Revenue Requirement**		**(Sum Lines 124 to 128)**	**0**

Attachment H

	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
130	Transmission Plant In Service		(Line 15)	0
131	Excluded Transmission Facilities	(Note M)	Attachment 5	0
132	Included Transmission Facilities		(Line 130 - 131)	0
133	Inclusion Ratio		(Line 132 / 130)	0.00%
134	Gross Revenue Requirement		(Line 129)	0
135	**Adjusted Gross Revenue Requirement**		(Line 133 * 134)	**0**
	Revenue Credits & Interest on Network Credits			
136	**Revenue Credits**		Attachment 3	0
137	**Interest on Network Credits**	(Note N)	Attachment 5	0
138	**Net Revenue Requirement**		**(Line 135 - 136 + 137)**	**0**
	Net Plant Carrying Charge			
139	Net Revenue Requirement		(Line 138)	-
140	Net Transmission Plant		(Line 15 - 23)	-
141	Net Plant Carrying Charge		(Line 139 / 140)	**0.0000%**
142	Net Plant Carrying Charge without Depreciation		(Line 139 - 73) / 140	**0.0000%**
143	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 139 - 73 - 109 - 120) / 140	**0.0000%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
144	Net Revenue Requirement Less Return and Taxes		(Line 138 - 127 - 128)	-
145	Increased Return and Taxes		Attachment 4	-
146	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 144 + 145)	-
147	Net Transmission Plant		(Line 15 - 23)	-
148	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 146 / 147)	**0.0000%**
149	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		(Line 146 - 73) / 147	**0.0000%**
150	**Net Revenue Requirement**		(Line 138)	-
151	True-up amount		Attachment 6	-
152	Plus any increased ROE calculated on Attachment 7		Attachment 7	-
153	Facility Credits under Section 30.9 of the APS OATT		Attachment 5	-
154	**Net Adjusted Revenue Requirement**		(Line 150 - 151 + 153)	-
	Annual Point-to-Point Transmission Rate			
155	Average of the 4 Summer CP	(Note L)	Network Transmission Peak Report	**0**
156	Annual Point-to-Point Transmission Rate		(Line 154 / 155)	**0.00**
157	Average of the 8 Non-Summer CP	(Note L)	Network Transmission Peak Report	**0**
158	Implied Non-Summer Revenue Requirement		((Line 156/12)*8* Line 157)	**0**
159	Implied Summer Revenue Requirement		(Line 138 - Line 158)	**0**
160	Implied Annualized Summer Point-to-Point Transmission Rate		((Line 154- line 158/Line 155/4)*12)	**0.00**
	Retail Transmission Rates			
161	Residential (kWh)		Rate Design Worksheet	**0.00000**
162	Gen Serv < 3MW Without Demand Meters -Includes All Customers 20 kW and less (kWh)		Rate Design Worksheet	**0.00000**
163	Gen Serv < 3MW (kW)		Rate Design Worksheet	**0.000**
164	Gen Serv > 3MW (kW)		Rate Design Worksheet	**0.000**

Notes

A Electric portion only

B Exclude Construction Work In Progress expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the Transmission Plan must be separately detailed on Attachment 5.
For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service

C Transmission Portion Only

D All EPRI Annual Membership Dues

E All Regulatory Commission Expenses

F Safety related advertising included in Account 930.1

G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.
If the tax rates change during a calendar year, an average tax rate will be used - calculated based on the number of days each was effective in the calendar year.

J ROE of 10.75%

K Education and outreach expenses relating to transmission, for example siting or billing

L Based on APS Network Transmission Peak Report

M Amount of transmission plant excluded from rates per Attachment 5.

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A.
Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmisison Owner whole on Line 137.

O AFUDC shall not be applied to the portion of a Network Upgrade for which the customer has provided the funds.

P Changes in depreciation or amortization rates must be filed with the Commission, as well as any new depreciation or amortization rates.

END

Arizona Public Service Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	0	0	0
ADIT-283	0	0	0	0
ADIT-190	0	0	0	0
ADITC-255	0	0	0	0
Subtotal-End of Year	0	0	0	0
Subtotal-Beginning of Year	0	0	0	0
End of Year for Est./Average for Final	0	0	0	0
Wages & Salary Allocator (Appendix A, Line 5)			0.0000%	
Gross Plant Allocator (Appendix A, Line 12)		0.0000%		
ADIT-End of Year for Estimate	0	0	0	0
ADIT-Average for Final	0	0	0	0

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

A ADIT-190	B Total	C Gas, Prod Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
Subtotal - p234						
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total						

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A ADIT- 282	B Total	C Gas, Prod Or Other	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
Subtotal - p275 (Form 1-F filer: see note 6 below)					0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total					0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A ADIT-283	B Total	C Gas, Prod Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
Subtotal - p277 (Form 1-F filer: see note 6, below)						
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total						

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

			Balance	Amortization	
1	Rate Base Treatment				
2	Balance to Attachment 1, Page 1, Transmission Related ADIT 255,				One or the other but not both.
3	Amortization				
4	Amortization to line 115 of Appendix A			-	
5	Total			-	
6	Total Form No. 1 (p 266 & 267)			-	
7	Difference /1		-	-	

/1 Difference must be zero

Arizona Public Service Company

Attachment 2 - Taxes Other Than Income Worksheet

Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
Plant Related		***Gross Plant Allocator***	
1 Transmission Personal Property Tax (directly assigned to Transmission)		100%	$ -
2 Capital Stock Tax		0.0000%	$ -
3 Gross Premium (insurance) Tax		0.0000%	$ -
4 PURTA		0.0000%	$ -
5 Corp License		0.0000%	$ -
		0.0000%	$ -
Total Plant Related	0		0
Labor Related		***Wages & Salary Allocator***	
6 Federal FICA & Unemployment & state unemployment			
Total Labor Related	0	0.0000%	0
Other Included		***Gross Plant Allocator***	
7 Miscellaneous	0		
Total Other Included	0	0.0000%	0
Total Included			0

Currently Excluded

8 Use & Sales Tax	0
9 Adjust state and local tax reserve	
10 Other Sales & Use Tax	0
11 Other Personal Property Tax (excluded)	
12	
13	
14	
15	
16	
17	
18	
19	
20	
21 Total "Other" Taxes (included on p. 263)	0
22 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	
23 Difference	-

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Arizona Public Service Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		-
2	Total Rent Revenues	(Sum Lines 1)	-
	Account 456 - Other Electric Revenues (Note 1)		
3	Scheduling, System Control & Dispatch (Ancillary Service)	p398 line 1 column g	
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (Note 4)		
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		-
6	Transitional Revenue Neutrality (Note 1)		
7	Transitional Market Expansion (Note 1)		
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	-
12	Line 17g		-
13	Total Revenue Credits		-

Revenue Adjustment to determine Revenue Credit

14 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 171 of Appendix A.

15 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

16 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	-
17b	Costs associated with revenues in line 17a	-
17c	Net Revenues (17a - 17b)	-
17d	50% Share of Net Revenues (17c / 2)	-
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.	-
17f	Net Revenue Credit (17d + 17e)	-
17g	Line 17f less line 17a	-
18	Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here but not included in the total above and is explained in the Cost Support; for example revenues associated with distribution facilities.	-
19	Amount offset in line 4 above	
20	Total Account 454 and 456	-

Composite Tax Rate 0.00%

Arizona Public Service Company

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

A	100 Basis Point increase in ROE and Income Taxes		Line 12 + Line 23	-
B	100 Basis Point increase in ROE			1.00%
Return Calculation				
1	Rate Base		Appendix A, Line 51	-
2	Debt %		Appendix A, Line 99	0.0%
3	Preferred %		Appendix A, Line 100	0.0%
4	Common %		Appendix A, Line 101	0.0%
5	Debt Cost		Appendix A, Line 102	0.00%
6	Preferred Cost		Appendix A, Line 103	0.00%
7	Common Cost	Appendix A % plus 100 Basis Pts	Appendix A, Line 104 + 1%	11.75%
8	Weighted Cost of Debt		Appendix A, Line 105	-
9	Weighted Cost of Preferred		Appendix A, Line 106	-
10	Weighted Cost of Common		Line 4 * Line 7	0.0000
11	**Total Return (R)**		Sum Lines 8 to 10	**0.0000**
12	**Investment Return = Rate Base * Rate of Return**		Line 11 * Line 1	**0**
Composite Income Taxes				
	Income Tax Rates			
13	FIT=Federal Income Tax Rate		Appendix A, Line 110	0.00%
14	SIT=State Income Tax Rate or Composite		Appendix A, Line 111	0.00%
15	p (percent of federal income tax deductible for state purposes)		Appendix A, Line 112	0.00%
16	T =1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		Appendix A, Line 113	0.00%
17	T/ (1-T)		Appendix A, Line 114	0.00%
	ITC Adjustment			
18	Amortized Investment Tax Credit		Appendix A, Line 115	-
19	1/(1-T)		Appendix A, Line 116	0.0000%
20	Net Plant Allocation Factor		Appendix A, Line 117	0.0000%
21	**ITC Adjustment Allocated to Transmission**		Appendix A, Line 118	**0**
22	**Income Tax Component = CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =**		Line 17*Line 12*(1-(Line 8/Line 11))	-
23	**Total Income Taxes**		**Line 21 + 22"**	-

Arizona Public Service Company

Attachment 5 - Cost Support

Plant in Service Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Details
Calculation of Transmission Plant In Service	Source		Balance For True up	Balance for Estimate
December	p206.58.b	2013		
January	company records	2014		
February	company records	2014		
March	company records	2014		
April	company records	2014		
May	company records	2014		
June	company records	2014		
July	company records	2014		
August	company records	2014		
September	company records	2014		
October	company records	2014		
November	company records	2014		
December	p207.58.g	2014		-
Transmission Plant In Service			-	-
Calculation of Distribution Plant In Service	Source			
December	p206.75.b	2013		
January	company records	2014		
February	company records	2014		
March	company records	2014		
April	company records	2014		
May	company records	2014		
June	company records	2014		
July	company records	2014		
August	company records	2014		
September	company records	2014		
October	company records	2014		
November	company records	2014		
December	p207.75.g	2014		-
Distribution Plant In Service			-	-
Calculation of Intangible Plant In Service	Source			
December	p204.5.b	2013		
December	p205.5.g	2014		-
Intangible Plant In Service			-	-
Calculation of General Plant In Service	Source			
December	p206.96.b	2013		
December	p207.96.g	2014		-
General Plant In Service			-	-
Calculation of Production Plant In Service	Source			
December	p204.46b	2013		
January	company records	2014		
February	company records	2014		
March	company records	2014		
April	company records	2014		
May	company records	2014		
June	company records	2014		
July	company records	2014		
August	company records	2014		
September	company records	2014		
October	company records	2014		
November	company records	2014		
December	p205.46.g	2014		-
Production Plant In Service			-	-
Total Plant In Service	Sum of averages above		0	0

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Details
Calculation of Transmission Accumulated Depreciation	Source		Balance For True up	Balance for Estimate
December	Prior year p219.25	2013		
January	company records	2014		
February	company records	2014		
March	company records	2014		
April	company records	2014		
May	company records	2014		
June	company records	2014		
July	company records	2014		
August	company records	2014		
September	company records	2014		
October	company records	2014		
November	company records	2014		
December	p219.25	2014		-
Transmission Accumulated Depreciation			-	-
Calculation of Distribution Accumulated Depreciation	Source			
December	Prior year p219.26	2013		
January	company records	2014		
February	company records	2014		
March	company records	2014		
April	company records	2014		
May	company records	2014		
June	company records	2014		
July	company records	2014		
August	company records	2014		
September	company records	2014		
October	company records	2014		
November	company records	2014		
December	p219.26	2014		-
Distribution Accumulated Depreciation			-	-
Calculation of Intangible Accumulated Depreciation	Source			
December	Prior year p200.21.c	2013		
December	p200.21c	2014		-
Accumulated Intangible Depreciation			-	-
Calculation of General Accumulated Depreciation	Source			
December	Prior year p219.28	2013		
December	p219.28	2014		-
Accumulated General Depreciation			-	-
Calculation of Production Accumulated Depreciation	Source			
December	Prior year p219.20 thru 219.24	2013		
January	company records	2014		
February	company records	2014		
March	company records	2014		
April	company records	2014		
May	company records	2014		
June	company records	2014		
July	company records	2014		
August	company records	2014		
September	company records	2014		
October	company records	2014		
November	company records	2014		
December	p219.20 thru 219.24	2014		-
Production Accumulated Depreciation			-	-
Total Accumulated Depreciation	Sum of averages above		0	0

Electric / Non-electric Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors					
	Accumulated Intangible Depreciation	p200.21.c				
	Materials and Supplies					
	Undistributed Stores Exp	p227.16c				
	Depreciation Expense					
	Intangible Amortization	p336.1d&e				

Transmission / Non-transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	End of Year for Est. Average for Final	Details
38	**Plant Held for Future Use**	p214	Total			-	
			Non-transmission Related				
			Transmission Related			-	

PBOPs Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	PBOBs	All other	Details
56	**Allocated General Expenses**					
	Account 926 (2006)				-	Base year
	Account 926 (Current Year)	p323.187b			-	Current Year
	Change in PBOP Expense			-		

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	EPRI Dues	Details
	Allocated General Expenses		A&G		
60	Less EPRI Dues	p352-353			

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G					
64	Regulatory Commission Exp Account 928	p350.1 thru 350.21				

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G					
68	General Advertising Exp Account 930.1	p323.191.b				

MultiState Workpaper

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Composite
Income Tax Rates						
111 SIT=State Income Tax Rate or Composite	AZ	NM	CA	TX	UT	

Education and Out Reach Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Education & Outreach	Other	Details
Directly Assigned A&G					
65 General Advertising Exp Account 930.1	p323.191.b				-

Excluded Gross Plant Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Excluded Gross Transmission Facilities	Description of the Facilities
Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
131 Excluded Gross Transmission Facilities			General Description of the Facilities
Instructions:		Enter $	None
1 Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.			Step Up Xfmrs
2 If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	Example	Or Enter $	West Phoenix to Lincoln Substation 345 kV transmission line
A Total investment in substation	1,000,000		
B Identifiable investment in Transmission (provide workpapers)	500,000		
C Identifiable investment in Distribution (provide workpapers)	400,000		
D Amount to be excluded (A x (C / (B + C)))	444,444		
			Add more lines if necessary

Transmission Related Account 242 Reserves

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	End of Year for Est. Average for Final	Allocation	Trans Related	Details
35 **Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)**				Enter $				
Directly Assignable to Transmission								
	Deposits							
	FERC Provision for Rate Refund							
	Land Rights							
		Sum Directly Transmission	-	-	-	100%	-	
Total Not Directly Assignable to Transmission		(A) Total Not Directly Transmission	-	-	-			
Labor Related, or General plant related								
	Vacation Accrual - Old Plan				-			
	Accrued Payroll				-			
	Medical - Dental				-			
	Short Term Software License				-			
	Workmen's Compensation Liability				-			
	Vacation Accrual				-			
	Vacation Accrual - Participants				-			
	SFAS 112				-			
	Incentive Accrual				-			
	Severance				-			
	SERBP				-			
	Deferred Compensation				-			
		(B) Sum Labor Related	-	-	-	0.0000%	-	
Other								
		(A) - (B)	-	-	-	0.00%	-	
Total Transmission Related Reserves			-	-	check		-	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	End of Year for Est. Average for Final	Allocation	Trans Related	Details
36 Prepayments							
Labor Related	Worksheet 5	-	-	-	0.000%	-	-
Plant Related	Worksheet 5	-	-	-	0.000%	-	-
100% Transmission Related	Worksheet 5	-	-	-	100.000%	-	-
Other (Excluded)	Worksheet 5	-	-	-	0.000%	-	-
						-	-

Materials & Supplies

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	End of Year for Est. Average for Final	Details
39	Stores Expense Undistributed	p227.16				
			-	-	-	
42	Transmission Materials & Supplies	p227.8			-	

Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Beg of year	End of Year	End of Year for Est. Average for Final	Description of the Credits
	Network Credits							
47	Outstanding Network Credits							General Description of the Credits
	December	Account 252	2013		-			
	December	Account 252	2014			-		
	Average Beginning and End of Year			-			-	
48	Accumulated Depreciation Associated with Facilities with Outstanding Network Credits							
	December	Account 252	2013		-			
	December	Account 252	2014			-		
	Average Beginning and End of Year			-			-	

Interest on Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Interest on Network Credits	Description of the Interest on the Credits
137	Interest on Network Credits		
			Add more lines if necessary

Arizona Public Service Company

Attachment 6 - Estimate and Reconciliation Worksheet

Exec Summary

Step	Month	Year	Action
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1.
2	April	Year 2	TO estimates all transmission Cap Adds, Retirements, and associated depreciation for Year 2 based on Months expected to be in service in Year 2.
3	April	Year 2	TO adds estimates from Step 2 to Appendix A
4	May	Year 2	Post results of Step 3 on APS web site.
5	June	Year 2	Results of Step 3 go into effect.
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1.
7	April	Year 3	Reconciliation - TO calculates the true up amount by subtracting the results of Step 6 by Step 3.
8	April	Year 3	Reconciliation - TO calculates interst and ammortization associated with the true up calculated in Step 7 and applies that amount to line 151 of the formula.
9	April	Year 3	TO estimates all transmission Cap Adds, Retirements, CWIP and associated depreciation for Year 3 based on Months expected to be in service and monthly CWIP balances in Year 3.
10	April	Year 3	TO adds 13 month average Cap Adds and retirements (line 16 and 24) to the Formula.
11	May	Year 3	Post results of Step 10 on APS web site.
12	June	Year 3	Results of Step 9 go into effect for the Rate Year 2.

Reconciliation details

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1.
Rev Req based on Year 1 data — Must run Appendix A to get this number (without estimated cap adds) from Appendix A

2 April Year 2 TO estimates all transmission Cap Adds, Retirements, and associated depreciation for Year 2 based on Months expected to be in service in Year 2.

	(A) Other Project PIS	(B) other retirements	(C) Project X PIS	(D) Project X PIS retirements	(E) Accumulated Balance Other Project PIS	(F) Accumulated Balance Project X PIS	(G) Accumulated Balance Total
Dec					0	0	0
Jan				0	-	-	-
Feb				0	-	-	-
Mar				0	-	-	-
Apr				0	-	-	-
May				0	-	-	-
Jun				0	-	-	-
Jul				0	-	-	-
Aug				0	-	-	-
Sep				0	-	-	-
Oct				0	-	-	-
Nov				0	-	-	-
Dec				0	-	-	-
Total	-	-	-	-	-	-	-

13 month avg of new plant additions = Col F + Col H — - — goes to line 16 of the formula

	(I) =F Total Other Project PIS	(J) Composite Trans Deprec Rate	(K) = I * J Depreciation Expense	(L) Accum Deprec	(M) = H Total Project X PIS	(N) Composite Trans Deprec Rate	(O) = L * M Depreciation Expense	(P) Accum Deprec
			-	-				
Jan	0	0.00%	-	-	-	0.00%	-	-
Feb	0	0.00%	-	-	-	0.00%	-	-
Mar	0	0.00%	-	-	-	0.00%	-	-
Apr	0	0.00%	-	-	-	0.00%	-	-
May	0	0.00%	-	-	-	0.00%	-	-
Jun	0	0.00%	-	-	-	0.00%	-	-
Jul	0	0.00%	-	-	-	0.00%	-	-
Aug	0	0.00%	-	-	-	0.00%	-	-
Sep	0	0.00%	-	-	-	0.00%	-	-
Oct	0	0.00%	-	-	-	0.00%	-	-
Nov	0	0.00%	-	-	-	0.00%	-	-
Dec	0	0.00%	-	-	-	0.00%	-	-
Total			-	-			-	-

13 mo. Avg accumulated depreciation = Col L + Col P: - goes to line 24 of the formula
Depreciation Expense = Col K + Col O - goes to line 74 of the formula

3 April Year 2 TO adds estimates from Step 2 to Appendix A

Include inputs to Appendix A Lines 16, 24, and 74

4 May Year 2 Post results of Step 3 on APS web site.
$ -

Must run Appendix A to get this number (with results of step 2)

5 June Year 2 Results of Step 3 go into effect.
-

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1.

Rev Req based on Prior Year data step 6 file

7 April Year 3 Reconciliation - TO calculates the true up amount by subtracting the results of Step 6 by Step 3.

	Prior Year True Up	First Year True up	Total True Up
Results of Step 6	$ -		$ -
Results of Step 5	$ -		$ -
True up w/o interest			$ -

True Up to be recovered $ - Divide True up w/o interest by the number of months the rate was in effect and place that result in the month that the rate went in effect in the interest calculation below

8 April Year 3

Reconciliation - TO calculates interst and ammortization associated with the true up calculated in Step 7 and applies that amount to line 151 of the formula.
Interest on Amount of Refunds or Surcharges
Interest 35.19a for 1st quarter Current Yr

Month	Yr	1/12 of Step 7	Interest 35.19a for and 35.19 b March Current Yr	Months	Interest	Refunds Owed
Jun	Year 1	-	0.00%	11.5	-	-
Jul	Year 1	-	0.00%	10.5	-	-
Aug	Year 1	-	0.00%	9.5	-	-
Sep	Year 1	-	0.00%	8.5	-	-
Oct	Year 1	-	0.00%	7.5	-	-
Nov	Year 1	-	0.00%	6.5	-	-
Dec	Year 1	-	0.00%	5.5	-	-
Jan	Year 2	-	0.00%	4.5	-	-
Feb	Year 2	-	0.00%	3.5	-	-
Mar	Year 2	-	0.00%	2.5	-	-
Apr	Year 2	-	0.00%	1.5	-	-
May	Year 2	-	0.00%	0.5	-	-
Total		-				-

Month	Yr	Balance	Interest	Amort	Balance
Jun	Year 2	-	0.00%	-	-
Jul	Year 2	-	0.00%	-	-
Aug	Year 2	-	0.00%	-	-
Sep	Year 2	-	0.00%	-	-
Oct	Year 2	-	0.00%	-	-
Nov	Year 2	-	0.00%	-	-
Dec	Year 2	-	0.00%	-	-
Jan	Year 3	-	0.00%	-	-
Feb	Year 3	-	0.00%	-	-
Mar	Year 3	-	0.00%	-	-
Apr	Year 3	-	0.00%	-	-
May	Year 3	-	0.00%	-	-
Total with interest				-	

The difference between the Reconciliation in Step 6 and the forecast in Prior Year with interest -

9 April Year 3 TO estimates all transmission Cap Adds, Retirements, CWIP and associated depreciation for Year 3 based on Months expected to be in service and monthly CWIP balances in Year 3.
Note: Jan and Feb are actuals, Mar-Dec forecasted. Retirements are not forecasted.

	(A) Other Project PIS	(B) other retirements	(C) Project X PIS	(D) Project X PIS retirements	(E) Accumulated Balance: Other Project PIS	(F) Accumulated Balance: Project X PIS	(G) Accumulated Balance: Total
Dec					0	0	0
Jan				0	-	-	-
Feb				0	-	-	-
Mar				0	-	-	-
Apr				0	-	-	-
May				0	-	-	-
Jun				0	-	-	-
Jul				0	-	-	-
Aug				0	-	-	-
Sep				0	-	-	-
Oct				0	-	-	-
Nov				0	-	-	-
Dec				0	-	-	-
Total	-	-	-		-	-	-

13 month avg of new plant additions = Col F + Col H - goes to line 16 of the formula

	(I) =F Total Other Project PIS	(J) Composite Trans Deprec Rate	(K) = I * J Depreciation Expense	(L) Accum Deprec	(M) = H Total Project X PIS	(N) Composite Trans Deprec Rate	(O) = L * M Depreciation Expense	(P) Accum Deprec
			-	-				
Jan	0	0.00%	-	-	-	0.00%	-	-
Feb	0	0.00%	-	-	-	0.00%	-	-
Mar	0	0.00%	-	-	-	0.00%	-	-
Apr	0	0.00%	-	-	-	0.00%	-	-
May	0	0.00%	-	-	-	0.00%	-	-
Jun	0	0.00%	-	-	-	0.00%	-	-
Jul	0	0.00%	-	-	-	0.00%	-	-
Aug	0	0.00%	-	-	-	0.00%	-	-
Sep	0	0.00%	-	-	-	0.00%	-	-
Oct	0	0.00%	-	-	-	0.00%	-	-
Nov	0	0.00%	-	-	-	0.00%	-	-
Dec	0	0.00%	-	-	-	0.00%	-	-
Total			-	-			-	-

13 mo. Avg accumulated depreciation = Col L + Col P: - goes to line 24 of the formula
Depreciation Expense = Col K + Col O - goes to line 74 of the formula

10 April Year 3 TO adds 13 month average Cap Adds and retirements (line 110 and 120) to the Formula.
Rev Req based on Year 2 data with estimated Cap Adds, Rets, and Deprec for Year 3 Cap Adds (Step 9) and True up of Year 1 data (Step 8)
Must run App A to get this # (with 13 mo. avg cap adds, depreciation for Year 3 cap adds)

11 May Year 3 Post results of Step 10 on APS web site.
$ -

12 June Year 3 Results of Step 9 go into effect for the Rate Year 2.
- Step 11 plus the difference between the Reconciliation in Step 6 and the forecast in Prior Year with interest

Arizona Public Service Company

Attachment 7 - Transmission Enhancement Charge Worksheet

line #		Formula Line		
1		152	Plus any increased ROE calculated on Attachment 7 =Incentive - Revenue Credit for the corresponding rate year	$ -
	Fixed Charge Rate (FCR) if not a CIAC			
2	A	142	Net Plant Carrying Charge without Depreciation	0.0000%
3	B	149	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	0.0000%
4	C		Line B less Line A	0.0000%
	FCR if a CIAC			
5	D	143	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	0.0000%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years

Beginning = 13 month Plant CWIP or Incentive Plant balance
Deprec = 13 month avg Accumulated Depreciation
Ending = Beginning - Deprec
Revenue= FCR* Ending + Ending

Total = Sum of Revenue for Project CWIP and PIS
Incentive = Total for "W Increased ROE" row
Revenue Credit = Total for "FCR W base ROE" row

	Details		Project A				Project B						
6	Life		-				-						
7	CIAC		No				No						
8	Increased ROE (Basis Points)		0				0						
9	FCR W base ROE		0.000%				0.000%						
10	FCR W increased ROE		0.000%				0.000%						
11	Investment												
12	Annual Depreciation Exp		-				-						
13	13 monthly Avg		-				-						
14		Invest Yr	Beginning	Depreciation	Ending	Revenue [(Beginning + Ending)/2* Line 11]	Beginning	Depreciation	Ending	Revenue [(Beginning + Ending)/2* Line 11]	Total	Incentive	Rev Credit
15	FCR W base ROE	2005	-	-	-	-	-	-	-	-	$ -		$ -
16	W Increased ROE	2005	-	-	-	-					$ -	$ -	
17	FCR W base ROE	2006	-	-	-	-					$ -		$ -
18	W Increased ROE	2006	-	-	-	-					$ -	$ -	
19	FCR W base ROE	2007	-	-	-	-					$ -		$ -
20	W Increased ROE	2007	-	-	-	-					$ -	$ -	
21	FCR W base ROE	2008	-	-	-	-					$ -		$ -
22	W Increased ROE	2008	-	-	-	-					$ -	$ -	
23	FCR W base ROE	2009	-	-	-	-					$ -		$ -
24	W Increased ROE	2009	-	-	-	-					$ -	$ -	
25	FCR W base ROE	2010	-	-	-	-					$ -		$ -
26	W Increased ROE	2010	-	-	-	-					$ -	$ -	
27	FCR W base ROE	2011	-	-	-	-					$ -		$ -
28	W Increased ROE	2011	-	-	-	-					$ -	$ -	
29	FCR W base ROE	2012	-	-	-	-					$ -		$ -
30	W Increased ROE	2012	-	-	-	-					$ -	$ -	
31	FCR W base ROE	2013	-	-	-	-					$ -		$ -
32	W Increased ROE	2013	-	-	-	-					$ -	$ -	
33	FCR W base ROE	2014	-	-	-	-					$ -		$ -
34	W Increased ROE	2014	-	-	-	-					$ -	$ -	
35	FCR W base ROE	2015	-	-	-	-					$ -		$ -
36	W Increased ROE	2015	-	-	-	-					$ -	$ -	
37	FCR W base ROE	2016	-	-	-	-					$ -		$ -
38	W Increased ROE	2016	-	-	-	-					$ -	$ -	
39	FCR W base ROE	2017	-	-	-	-					$ -		$ -
40	W Increased ROE	2017	-	-	-	-					$ -	$ -	
41	FCR W base ROE	2018	-	-	-	-					$ -		$ -
42	W Increased ROE	2018	-	-	-	-					$ -	$ -	
43	FCR W base ROE	2019	-	-	-	-					$ -		$ -
44	W Increased ROE	2019	-	-	-	-					$ -	$ -	
45	FCR W base ROE	2020	-	-	-	-					$ -		$ -
46	W Increased ROE	2020	-	-	-	-					$ -	$ -	
47	FCR W base ROE	2021	-	-	-	-					$ -		$ -
48	W Increased ROE	2021	-	-	-	-					$ -	$ -	
49	FCR W base ROE	2022	-	-	-	-					$ -		$ -
50	W Increased ROE	2022	-	-	-	-					$ -	$ -	
51	FCR W base ROE	2023	-	-	-	-					$ -		$ -
52	W Increased ROE	2023	-	-	-	-					$ -	$ -	
53	FCR W base ROE	2024	-	-	-	-					$ -		$ -
54	W Increased ROE	2024		-	-	-					$ -	$ -	
55													$ -
56												$ -	$ -

Arizona Public Service Company

Attachment 8 - Depreciation Rates

Plant Account	Depreciation Rates
352.01 - Structures	1.84%
353 - Station Equipment	2.14%
354 - Towers and Fixtures	1.34%
355.01 - Poles and Fixtures - Wood	2.21%
355.02 - Poles and Fixtures - Steel	2.10%
356 - Overhead Conductors and Devices	1.87%
357 - Underground Conduit	1.55%
358 - Underground Conductors and Devices	1.33%

Appendix R

RULE-BASED COMPLIANCE REQUIREMENTS ELIMINATED OR WAIVED

Rule	Topic	Frequency	Description
R14-2-1613(A)	Retail Competition	Annual	Report on competitive services and standard offer services provided by Electric Service Providers and Affected Utilities
R14-2-1617	Retail Competition	Annual	Provide a Consumer Disclosure Label containing price, fuel mix, and emissions data for the prior year
R14-2-2308	Net Metering	Annual	Provide the inverter or generator rating, monthly energy deliveries and if available the monthly peak demand for each net metering facility

DECISION-BASED COMPLIANCE REQUIREMENTS ELIMINATED OR WAIVED

Decision	Docket	Topic	Frequency	Description
Redundant Filings				
70531 Page 22, line 1 (09/30/08)	E-01345A-08-0106	RES	Annual	Report any damage payments received related to the Solana PPA contract
72058 Page 10, line 25 (01/06/11)	E-01345A-10-0314	RES	Annual	Report any damage payments received related to the Perrin Ranch PPA contract
71275 Page 15, line 4 (9/17/09)	E-01345A-09-0263	RES	Annual	Report production from systems installed as a result of the 2009 school UFI program and do not report "phantom" production
71244 Page 8, line 13 (08/06/09)	E-01345A-09-0255	Rates	Annual	Report detailing transmission projects and O&M costs included in each Transmission Cost Adjustor reset and expected future TCA costs
Outdated Filings				
68112 Page 7, line 3 (09/09/05)	E-01345A-03-0775 E-01345A-04-0657	Bill Estimation	Non-dated	Participate in benchmarking studies that compare APS estimation and other billing practices to other utilities

Decision	Docket	Topic	Frequency	Description
68645 Page 9, line 3 (04/12/06)	E-01345A-05-0674	Rates	Annual	Provide load shape data for participants served under experimental rates ET-2 and ECT-2
69569 Page 8, line 8 (05/21/07)	E-01345A-05-0711	Bill Estimation	Non-dated	Update allocation data for summer/winter on-peak usage, load factor, and usage per day when change is more than 5%
71448 Page 61, line 12 (12/30/09)	E-01345A-08-0172	Rate Case	As necessary	Notify Commission prior to replacing full-time employees with off-shored employees
71448 Page 61, line 26 (12/30/09)	E-01345A-08-0172	Rate Case	Annual	Develop a Carbon Credit Tracking Mechanism
71958 Page 6, line 26 (11/01/10)	E-01345A-10-0013	RES	Annual	Notify Commission if the Bagdad REC and Energy project has precluded any other commercial system from receiving incentives
72022 Page 29, line 1 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Summarize RES reports (Compliance Report and Implementation Plans) with 1-2 page summaries and a PowerPoint presentation
72022 Page 28, line 22 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Disclose if affiliates, employees, or directors have financial or other interest in renewable energy projects
72582 Page 14, line 22 (09/15/11)	E-01345A-10-0123	Technology Innovation	Annual	Report on the development of the EV market in APS territory
73089 (04/05/12) Page 62, line 1	E-01345A-11-0232	DSM/EE	Annual	Present an overview of the DSM Annual Progress Report at an Open Meeting
73089 (04/05/12) Page 61, line 6	E-01345A-11-0232	DSM/EE	Annual	Report spending associated with non-energy efficiency measures in the Appliance Recycling program
73089 (04/05/12) Page 61, line 11	E-01345A-11-0232	DSM/EE	Annual	Provide information on how savings from the Bid for Efficiency pilot measure are verified