0000102931

Transcript Exhibit(s)

Docket #(s): E-01345A-08-0172

Exhibit # : APSH-APS35, APS37, APS38

ASBA1, AECC1-AECC4, Mayes1-Mayes8

Pierce1-Pierce3, FEA1, FEA2, IBEW1-IBEW3
Interwest1, Kroger1, Kroger2, Mesquite/M1,
RUCO1-RUCO4

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Arizona Corporation Commission
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2009 JUL 17 P 4: 34

AZ CORP COMMISSION
DOCKET CONTROL

July 17, 2009

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AZ CORP COMM
Director Utilities

Docket Control
Arizona Corporation Commission
1200 west Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY SUPPLEMENTAL DIRECT TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT
DOCKET NO. E-01345A-08-0172

Attached is Supplemental Direct Settlement Testimony of Arizona Public Service Company witness David J. Rumolo. This testimony supplements the Direct Settlement Testimony that was previously filed on July 1, 2009 in this matter.

Sincerely,

Leland R. Snook

LS/dst

Attachments

CC: Brian Bozzo
Terri Ford
Barbara Keene
Parties of Record

EXHIBIT
APS 14
ADMITTED

Copies of the foregoing emailed or mailed
This 17th day of July 2009 to:

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SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY

OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

July 17, 2009

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Revised Service Schedule 8 ..... Attachment DJR-2-S(Supplemental)

SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY
OF DAVID J. RUMOLO

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David J. Rumolo. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. ARE YOU THE SAME DAVID J. RUMOLO WHO PREVIOULSY FILED DIRECT TESTIMONY IN SUPPORT OF ARIZONA PUBLIC SERVICE COMPANY'S APPLICATION AND LATER DIRECT SETTLEMENT TESTIMONY IN THIS DOCKET?

A. Yes, I filed Direct Testimony in support of Arizona Public Service Company's ("APS" or "Company") application for rate relief and Direct Settlement Testimony in support of the proposed Settlement Agreement ("Agreement").

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY?

A. My Direct Settlement Testimony included several bill comparisons of typical customer bills before and after the implementation of rates proposed in the Agreement. Those bill comparisons included estimated impacts of proposed changes for the recovery of energy efficiency and demand response program costs through the Demand Side Management Adjustment Charge ("DSMAC") and renewable energy program costs through the Renewable Energy Standard Adjustor ("RES"). In the time since my Direct Settlement Testimony was prepared, APS filed new implementation plans for renewable energy programs and energy efficiency programs. These plans implement the renewable/energy

efficiency goals and objectives that are significant elements of the Agreement. They also identify the required changes in the DSMAC and RES needed to fund the programs described in the plans. The revised bill comparisons (Attachment DJR-1-S (Supplemental)) include the proposed DSMAC and RES charges that were included in the implementation plans. These updated bill comparisons supersede the bill comparisons that were provided by the Settlement Parties on May 15, 2009 and the bill comparisons that were attached to my Direct Settlement Testimony.

My Supplemental Direct Settlement Testimony also proposes additional modifications to Service Schedule 8, Bill Estimation. As before, these modifications are needed because of the introduction of new rate designs as part of the Agreement. The modifications address the procedures that will be followed if APS cannot obtain a meter reading for a customer on the new residential super-peak rate schedule or the new residential critical peak pricing schedule. These are new rate schedules that will be offered to customers after Commission approval of the Agreement.

Q. THE RATE COMPARISONS PRESENT TWO VARIATIONS FOR THE DSMAC. PLEASE DESCRIBE THE DIFFERENCE IN THE CALCULATIONS.

A. The Energy Efficiency Implementation Plan that was filed on July 15, 2009 and the corresponding DSMAC can be considered a transitional plan in that it moves from recovery of costs on an historical after the fact basis to more concurrent cost recovery. In this first year of transition, the new DSMAC, which will become effective in March 2010 if approved by the Commission, will need to recover both unrecovered 2009 program costs (the historical element) and estimated 2010 program costs per the approved Energy Efficiency

Implementation Plan (the more concurrent element). In other words, and only for this initial charge, the program costs for two years would be covered in this one adjustment to the DSMAC. Although these costs are associated with cost-effective energy efficiency and demand response programs, the compound impact of this transition DSMAC is not insignificant. Because of this, APS has prepared an alternative DSMAC adjuster proposal that would recover the 2009 program costs over a three-year period. This will lower the bill impact to customers in 2010. APS would not seek any interest on the unrecovered balance during the three-year recovery period. Therefore, the difference between the two sets of bill comparisons is simply the recovery period used for the 2009 energy efficiency program costs.

Q. DOES THE COMMISSION NEED TO DECIDE WHICH ALTERNATIVE DSMAC RECOVERY CHARGE SHOULD BE IMPLEMENTED AS PART OF THE AGREEMENT?

A. Not necessarily. That decision could be made during the consideration of approval of the implementation plan. Because the Energy Efficiency Implementation Plan is contingent upon approval of the Agreement, and APS has asked for such approval of the Plan no later than the overall approval of the Agreement, this issue could be resolved in either forum.

Q. WOULD YOU PLEASE DISCUSS AN ILLUSTRATIVE EXAMPLE OF THE BILL COMPARISIONS THAT ARE ATTACHED TO YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, I will use the average bill comparison for all residential customers which is the first bill comparison found in the attachment. The comparison shows the increases in base rates and includes the current DSMAC that became effective in April 2009. The increase in the monthly base bill for the typical residential customer who uses 1,177 kWh per month is $6.24. Beneath the base bill

comparisons, the incremental impacts of the new DSMAC and RES are shown. For example, the increase in the DSMAC for the average residential customer per month is $1.71. Of the total costs that will be collected through the DSMAC approximately 26% recovers 2009 energy efficiency program costs, 68% recovers 2010 energy efficiency program costs and the balance of 6% recovers both 2009 and 2010 demand response program costs. If the Commission elects to have APS recover the 2009 costs over a three-year period, the DMSAC increase would be $1.27 per month for the typical residential customer rather than $1.71. When the attached bill comparisons are compared to the bill comparisons provided on May 15, it can be seen that the increase in the RES charge is now lower. The average residential RES charge increase shown on the bill comparisons provided on May 15 was $0.86 per month and is now $0.24 per month. The lower RES charge is due to lower costs in the detailed RES implementation plan than had been anticipated in the previous rate comparisons.

Q. WHAT IS THE NET DIFFERENCE IN THE BILL COMPARISIONS ATTACHED TO THIS SUPPLEMENTAL TESTIMONY TO THAT PROVIDED ON MAY 15, 2009?

A. As I noted earlier, the RES charge is lower than APS estimated on May 15, 2009 while the DSMAC is higher. If a three-year transition is used to recover 2009 energy efficiency costs, the combined effect of the changes results in an increase of approximately 14 cents per month for an average residential bill compared to what was estimated on May 15. If 2009 energy efficiency costs are all recovered in 2010, the combined effect of the changes would result in an increase of approximately 58 cents per month for an average residential bill over the May 15 estimate.

Q. BOTH THE DSM AND RES PROGRAM COSTS ARE DIFFERENT FROM THOSE USED IN THE MAY 15, 2009 BILL COMPARISONS AND

ALSO FROM THE AMOUNT REFERENCED IN THE AGREEMENT RELATIVE TO DSM. ARE YOU THE WITNESS TO EXPLAIN THOSE DIFFERENCES?

A. No. Barbara Lockwood can discuss why the RES estimate is lower, and Jim Wontor is the witness to address the new estimated DSM (including demand response) costs.

II. SERVICE SCHEDULE 8

Q. ARE YOU PROPOSING ANY ADDITIONAL CHANGES TO SERVICE SCHEDULE 8 IN THIS SUPPLEMENTAL TESTIMONY?

A. Yes. Service Schedule 8 describes the procedures and protocols that APS uses to estimate energy consumption and demand when a meter reading cannot be obtained. In the APS rate case application and in my Direct Settlement Testimony, proposed modifications to Service Schedule 8 to accommodate new rate offerings were discussed. However, the estimation procedures that will be utilized for residential customers participating in the critical peak pricing pilot that is discussed in the Agreement was not included in proposed Schedule 8. These procedures have been included in the proposed Service Schedule 8 which is attached (DJR-2-S (Supplemental)). The proposed Service Schedule 8 as DJR-2-S (Supplemental) also includes some clarification of the bill estimation procedures that would be used for the residential super-peak rate, Schedule ET-SP.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY?

A. Yes.

Monthly Bill
Rate Case Settlement Proposal
Revised July 13, 2009

ARIZONA PUBLIC SERVICE COMPANY
Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 100% of 2009 Carry Forward Costs Recovered in 2010

Residential (Average - All Rates)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)		Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	1,177	1,177		1,417	1,417	936	936
Base Rates	$ 116.78	$ 131.66		$ 151.17	$ 170.44	$ 82.38	$ 92.88
PSA- Forward Component	5.98	-		7.20	-	4.75	-
PSA - Historical Component	0.31	0.31		0.37	0.37	0.24	0.24
Interim Rate Adjustor (January 2009)	2.66	-		3.20	-	2.12	-
TCA (July 1, 2008)	1.42	1.42		1.71	1.71	1.13	1.13
CRCC (April 2005)	0.40	0.40		0.48	0.48	0.32	0.32
EIS (July 2007)	0.19	0.19		0.23	0.23	0.15	0.15
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.72	0.72		0.86	0.86	0.57	0.57
Total	$ 131.63	$ 137.87		$ 168.39	$ 177.26	$ 94.83	$ 98.46
Bill Impact (3)		$ **6.24**			$ 8.87		$ 3.63
Percent Bill Impact		**4.74%**					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 1.71	1.30%		$ 2.05		$ 1.36
Increase from Projected 2010 RES (5)		$ 0.24	0.18%		$ 0.24		$ 0.24

Residential (Rate E-12)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	763	763		880	880	645	645
Base Rates	$ 81.71	$ 92.19		$ 102.11	115.21	$ 61.30	69.16
PSA- Forward Component	3.88	-		4.47	-	3.28	-
PSA - Historical Component	0.20	0.20		0.23	0.23	0.17	0.17
Interim Rate Adjustor (January 2009)	1.73	-		1.99	-	1.46	-
TCA (July 1, 2008)	0.92	0.92		1.06	1.06	0.78	0.78
CRCC (April 2005)	0.26	0.26		0.30	0.30	0.22	0.22
EIS (July 2007)	0.12	0.12		0.14	0.14	0.10	0.10
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.46	0.46		0.53	0.53	0.39	0.39
Total	$ 92.45	$ 97.32		$ 114.00	$ 120.64	$ 70.87	$ 73.99
Bill Impact (3)		$ **4.87**			$ 6.64		$ 3.12
Percent Bill Impact		**5.27%**					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 1.10	1.19%		$ 1.27		$ 0.93
Increase from Projected 2010 RES (5)		$ 0.24	0.26%		$ 0.24		$ 0.24

ARIZONA PUBLIC SERVICE COMPANY
Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 100% of 2009 Carry Forward Costs Recovered in 2010

Commercial (Rate E-32)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)	Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	8,769	8,769	9,746	9,746	7,792	7,792
Base Rates	$ 781.15	$ 884.44	$ 921.60	$ 1,043.47	$ 640.69	$ 725.41
PSA- Forward Component	44.55	-	49.51	-	39.58	-
PSA - Historical Component	2.26	2.26	2.51	2.51	2.01	2.01
Interim Rate Adjustor (January 2009)	19.82	-	22.03	-	17.61	-
TCA (July 1, 2008)	15.22	15.22	16.91	16.91	13.53	13.53
CRCC (April 2005)	2.96	2.96	3.29	3.29	2.63	2.63
EIS (July 2007)	1.41	1.41	1.56	1.56	1.25	1.25
RES (Jan 1, 2009)	69.60	69.60	77.35	77.35	61.85	61.85
DSMAC (April 2009)	6.52	6.52	7.24	7.24	5.79	5.79
Total	$ 943.49	$ 982.41	$ 1,102.00	$ 1,152.33	$ 784.94	$ 812.47
Bill Impact (3)		**$ 38.92**		$ 50.33		$ 27.53
Percent Bill Impact		**4.13%**				
Reduction from accelerated reset of PSA Historical Component		TBD	TBD	TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 12.70	1.35%	$ 14.11		$ 11.28
Increase from Projected 2010 RES (5)		$ 5.22	0.55%	5.80		4.64

Industrial (Rate E34/35 Medium Load Factor)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	2,250,284	2,250,284	2,344,877	2,344,877	2,155,690	2,155,690
Base Rates	$ 201,730.50	$ 228,929.00	$ 210,209.00	$ 238,550.00	$ 193,252.00	$ 219,308.00
PSA- Forward Component	11,431.45	-	11,911.98	-	10,950.91	-
PSA - Historical Component	580.58	580.58	604.98	604.98	556.17	556.17
Interim Rate Adjustor (January 2009)	5,085.64	-	5,299.42	-	4,871.86	-
TCA (July 1, 2008)	2,666.44	2,666.44	2,778.52	2,778.52	2,554.35	2,554.35
CRCC (April 2005)	760.60	760.60	792.57	792.57	728.62	728.62
EIS (July 2007)	360.05	360.05	375.18	375.18	344.91	344.91
RES (Jan 1, 2009)	353.78	353.78	353.78	353.78	353.78	353.78
DSMAC (April 2009)	2,106.39	2,106.39	2,194.93	2,194.93	2,017.84	2,017.84
Total	$ 225,075.43	$ 235,756.84	$ 234,520.36	$ 245,649.96	$ 215,630.44	$ 225,863.67
Bill Impact (3)		**$ 10,681.41**		$ 11,129.60		$ 10,233.23
Percent Bill Impact		**4.75%**				
Reduction from accelerated reset of PSA Historical Component		TBD	TBD	TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 4,815.05	2.14%	$ 5,017.45		$ 4,612.64
Increase from Projected 2010 RES (5)		$ 26.48	0.01%	26.48		26.48

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of May 1, 2009.
(2) Bill impacts reflect the proposed increase in base rates, reset of interim surcharge to zero, and reset of PSA Forward Component charge to zero.
(3) Bill impacts for commercial and industrial customers are less than residential on a percentage basis because these customer classes were assessed proportionally more for the interim adjustor and the PSA. The base rates reflect approximately the same percentage increase as residential.
(4) DSMAC costs reflect the 2010 implementation plan and the proposed Plan for Administration. 2009 carry forward costs are recovered in 2010.
(5) RES impacts are based on the 2010 implementation plan filed in July 2009.
Of the projected increase in the RES budget for 2010, only about $1 to $2 million is attributable to the settlement.

Monthly Bill
Rate Case Settlement Proposal
Revised July 13, 2009

ARIZONA PUBLIC SERVICE COMPANY
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PSA- Forward Component	5.98	-		7.20	-	4.75	-
PSA - Historical Component	0.31	0.31		0.37	0.37	0.24	0.24
Interim Rate Adjustor (January 2009)	2.66	-		3.20	-	2.12	-
TCA (July 1, 2008)	1.42	1.42		1.71	1.71	1.13	1.13
CRCC (April 2005)	0.40	0.40		0.48	0.48	0.32	0.32
EIS (July 2007)	0.19	0.19		0.23	0.23	0.15	0.15
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.72	0.72		0.86	0.86	0.57	0.57
Total	$ 131.63	$ 137.87		$ 168.39	$ 177.26	$ 94.83	$ 98.46
Bill Impact (3)		$ 6.24			$ 8.87		$ 3.63
Percent Bill Impact		4.74%					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 1.27	0.96%		$ 1.52		$ 1.01
Increase from Projected 2010 RES (5)		$ 0.24	0.18%		$ 0.24		$ 0.24

Residential (Rate E-12)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	763	763		880	880	645	645
Base Rates	$ 81.71	$ 92.19		$ 102.11	115.21	$ 61.30	69.16
PSA- Forward Component	3.88	-		4.47	-	3.28	-
PSA - Historical Component	0.20	0.20		0.23	0.23	0.17	0.17
Interim Rate Adjustor (January 2009)	1.73	-		1.99	-	1.46	-
TCA (July 1, 2008)	0.92	0.92		1.06	1.06	0.78	0.78
CRCC (April 2005)	0.26	0.26		0.30	0.30	0.22	0.22
EIS (July 2007)	0.12	0.12		0.14	0.14	0.10	0.10
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Percent Bill Impact		5.27%					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 0.82	0.89%		$ 0.95		$ 0.69
Increase from Projected 2010 RES (5)		$ 0.24	0.26%		$ 0.24		$ 0.24

ARIZONA PUBLIC SERVICE COMPANY
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Revised RES, DSMAC 33% of 2009 Carry Forward Costs Recovered in 2010

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PSA- Forward Component	44.55	-		49.51	-	39.58	-
PSA - Historical Component	2.26	2.26		2.51	2.51	2.01	2.01
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CRCC (April 2005)	2.96	2.96		3.29	3.29	2.63	2.63
EIS (July 2007)	1.41	1.41		1.56	1.56	1.25	1.25
RES (Jan 1, 2009)	69.60	69.60		77.35	77.35	61.85	61.85
DSMAC (April 2009)	6.52	6.52		7.24	7.24	5.79	5.79
Total	$ 943.49	$ 982.41		$ 1,102.00	$ 1,152.33	$ 784.94	$ 812.47
Bill Impact (3)		$ 38.92			$ 50.33		$ 27.53
Percent Bill Impact		4.13%					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 9.43	1.00%		$ 10.48		$ 8.38
Increase from Projected 2010 RES (5)		$ 5.22	0.55%		5.80		4.64

Industrial (Rate E34/35 Medium Load Factor)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	2,250,284	2,250,284		2,344,877	2,344,877	2,155,690	2,155,690
Base Rates	$ 201,730.50	$ 228,929.00		$ 210,209.00	$ 238,550.00	$ 193,252.00	$ 219,308.00
PSA- Forward Component	11,431.45	-		11,911.98	-	10,950.91	-
PSA - Historical Component	580.58	580.58		604.98	604.98	556.17	556.17
Interim Rate Adjustor (January 2009)	5,085.64	-		5,299.42	-	4,871.86	-
TCA (July 1, 2008)	2,666.44	2,666.44		2,778.52	2,778.52	2,554.35	2,554.35
CRCC (April 2005)	760.60	760.60		792.57	792.57	728.62	728.62
EIS (July 2007)	360.05	360.05		375.18	375.18	344.91	344.91
RES (Jan 1, 2009)	353.78	353.78		353.78	353.78	353.78	353.78
DSMAC (April 2009)	2,106.39	2,106.39		2,194.93	2,194.93	2,017.84	2,017.84
Total	$ 225,075.43	$ 235,756.84		$ 234,520.36	$ 245,649.96	$ 215,630.44	$ 225,863.67
Bill Impact (3)		$ 10,681.41			$ 11,129.60		$ 10,233.23
Percent Bill Impact		4.75%					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 3,557.53	1.58%		$ 3,707.07		$ 3,407.98
Increase from Projected 2010 RES (5)		$ 26.48	0.01%		26.48		26.48

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of May 1, 2009.
(2) Bill impacts reflect the proposed increase in base rates, reset of interim surcharge to zero, and reset of PSA Forward Component charge to zero.
(3) Bill impacts for commercial and industrial customers are less than residential on a percentage basis because these customer classes were assessed proportionally more for the interim adjustor and the PSA. The base rates reflect approximately the same percentage increase as residential.
(4) DSMAC costs reflect the 2010 implementation plan and the proposed Plan for Administration. 2009 carry forward costs are phased in over three years.
(5) RES impacts are based on the 2010 implementation plan filed in July 2009.
Of the projected increase in the RES budget for 2010, only about $1 to $2 million is attributable to the settlement.

SERVICE SCHEDULE 8
BILL ESTIMATION

Arizona Public Service Company (APS or Company) regularly encounters situations in which APS cannot obtain a complete and valid meter read. Situations that result in an estimated meter read include inclement weather, lack of access to a customer's meter, energy diversion, labor unavailability and equipment malfunction. Without a valid meter read, the customer's energy usage and/or demand must be estimated in order to render a bill for the missing read period. A bill based on estimated usage is often referred to as an "estimated bill."

APS uses situation specific methods to estimate electrical usage to ensure that the most accurate usage estimate is obtained. This Schedule describes the estimation methods and procedures used when an actual meter read cannot be obtained or when energy diversion and/or meter tampering has occurred. The estimating process is applicable to customers receiving Standard Offer service and to direct access customers receiving unbundled delivery service from the Company.

1. GENERAL

1.1 Estimating a read for energy (kWh) and/or demand (kW) is performed in accordance with the provisions of this Schedule or such supplemental or amendatory guidelines or regulations as may hereafter be established and as provided by law.

1.2 This Schedule shall be considered a part of all rate schedules.

1.3 Upon discovery of the need to estimate kWh or kW, Company will make reasonable attempt (s) to secure an accurate meter reading and to resolve no-access issues.

1.4 Company is not obligated to obtain, or attempt to obtain, a customer supplied meter read prior to sending an estimated bill. In circumstances where APS has agreed in writing to permit customer supplied meter reads in accordance with Arizona Corporation Commission (ACC or Commission) regulations and that customer fails to provide Company with the meter read, estimation is also allowed.

1.5 Estimates due to equipment malfunctions may exceed one month if the malfunction of Company owned or maintained equipment could not be reasonably discovered and/or corrected before the need for additional estimates, or if the equipment malfunction is with regard to customer-owned or maintained equipment.

1.6 This schedule is not intended to supersede the Commission's rules and regulations in effect at the time the Commission approved this Schedule 8 without a specific decision of the Commission.

2. BILL ESTIMATION

2.1 The causes that result in an estimated bill include but are not limited to:

2.1.1 Inclement weather where conditions prevent meter access or compromise APS employee safety as determined by Company.

2.1.2 Lack of access to the meter either due to conditions on the customer's premise or to road closures that prevent access to the customer's premise.

2.1.3 Equipment or meter failure or malfunction with no reliable information retained by the meter.

2.1.4 Labor unavailability due to circumstances such as unforeseen illness, natural disasters, or other extreme events.

2.1.5 Meter tampering or energy diversion resulting in a lack of accurate metered consumption information.

2.1.6 An electronic meter reading is obtained, but the data cannot be transferred to a billing computer.

2.1.7 Only a partial read for a meter (for example, the total kWh read is obtained from a time-of-use meter, but on-peak kWh and/or kW reads are unavailable). Company will use the read available, and estimate the missing read(s).

2.2 The following defines certain conditions under which a bill is not considered estimated:

2.2.1 A bill based on an actual kWh read, following an estimated bill. This is considered a "true-up" bill and has an explanation of "true-up" on the bill.

2.2.2 Rate changes in the middle of the billing cycle.

2.2.3 A meter failure or malfunction which does not prevent the meter from accurately recording customer usage or from being read.

2.2.4 The meter read is not available using electronic meter reading devices, but data is obtained from a visual meter reading.

2.2.5 Meter reading information is not available because the service is provided on an un-metered basis.

2.2.6 Unbundled service for direct access customers is provided on the basis of load profiles in accordance with ACC regulations rather than using interval data metering.

2.2.7 When Company determines a meter is misread, but the actual read on the meter at the time it was read can be determined, Company makes a manual correction to the incorrect read. This includes, but is not limited to, the following examples:

2.2.7.1 A shut-off read is obtained, and on the same day the monthly meter read is taken and is higher by 1 kWh. The monthly meter read is changed to the same read as the shut off read.

2.2.7.2 The serviceman enters a shut-off or turn-on read and then calls into the office to say he entered the read for the wrong address. The correct reads are entered for the appropriate addresses.

2.2.7.3 Accurate consumption information can be obtained from load research meters.

2.2.8 A bill is estimated, and then rebilled when an actual read is obtained for the same billing period. The first bill is considered an estimated bill and is coded as such. The subsequent bill is considered a corrected bill and is not coded as an estimate, but does contain "corrected bill" language.

3. BILL ESTIMATION METHODS

The following section describes the estimation methods used to estimate energy consumption and demand for most instances. Estimation techniques required where special circumstances exist, such as initial bills, are also described. In general, the estimation methodologies utilize historical data.

3.1 ENERGY ESTIMATION (kWh)

For energy estimation, the following hierarchy is used: 1) The estimate will be based on the customer-specific prior month's energy consumption unless that month was an initial bill. 2) If the prior month's customer-specific energy consumption is not available or was an initial bill, the estimate will be based on the customer-specific energy consumption for the same month in the prior year. 3) If the customer-specific prior month or same month last year energy consumption is unavailable but adequate seasonal customer history exists, energy consumption will be estimated based on daily usage during six months of the same season. 4) If customer-specific energy consumption is not available, the estimate will be based on the prior month's energy consumption at that premise unless that month was an initial bill. 5) If prior month's premise energy consumption is not available or was an initial bill, the premise energy consumption for the same month in the prior year will be used to estimate consumption. 6) If premise-specific prior month or same month last year is unavailable but adequate seasonal premise history exists, energy consumption will be estimated based on daily usage during six months of the same season. 7) When adequate customer or premise history is not available, the estimate is based on the customer class average usage found in Section 3.3.1.

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak energy consumption.

For customers served under rate schedules SC-S, EPR-2, EPR-5, and EPR-6 the hierarchy listed above will be used to estimate the energy consumed by the Customer. Section 3.1.3 below shall be used to estimate any excess energy purchased by the Utility. For customers served under rate schedules E-56, CPP-RES and CPP-GS, the energy estimation will be addressed on a case-by-case basis.

For bill estimation purposes, the Summer Season is defined as May through October and the Winter Season is defined as November through April.

The energy estimation methods are described in detail below.

Previous Month Method

Estimated energy usage is calculated as follows:

1. Determine the number of days for the previous month's billing period.

2. Determine the kWh for the previous month's billing period.

3. Divide the previous month kWh by the previous month number of days to determine p~~P~~revious m~~M~~onth per d~~D~~ay u~~U~~sage.

4. Multiply the p~~P~~revious m~~M~~onth per d~~D~~ay u~~U~~sage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Same Month Prior Year Method

Estimated energy is calculated as follows:

1. Determine the number of days for the same month of the previous year's billing period.

2. Determine the kWh for the same month of the previous year's billing period.

3. Divide the same month prior year's kWh by the same month prior year's number of days to get s~~S~~ame m~~M~~onth p~~P~~rior y~~Y~~ear per d~~D~~ay u~~U~~sage.

4. Multiply the s~~S~~ame m~~M~~onth p~~P~~rior y~~Y~~ear per d~~D~~ay usage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Seasonal Average Method

Estimated energy is calculated as follows:

Where there is sufficient seasonal history (the number of days billed in the season is between 165 and 195 days), energy is estimated by calculating the average use per day for the same season as the billing period with the missing read. The resulting per day usage is multiplied by the number of days in the missing-read billing period to yield the usage estimate for the billing period. Seasonal average is calculated as follows:

1. Determine the total number of days from each of the previous six same-season months to yield s~~S~~easonal t~~T~~otal d~~D~~ays.

2. Add the kWh from each of the previous six same-season months to yield s~~S~~easonal t~~T~~otal kWh.

3. Divide s~~S~~easonal t~~T~~otal kWh by s~~S~~easonal t~~T~~otal d~~D~~ays to yield the s~~S~~easonal p~~P~~er d~~D~~ay u~~U~~sage.

4. Multiply the s~~S~~easonal p~~P~~er d~~D~~ay u~~U~~sage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Class Average Method

Estimated energy usage is calculated as follows:

Where neither customer nor premise history is available, energy is estimated by calculating the average use per day for customer served under the same rate schedule. The resulting per day usage is multiplied by the number of days in the missing-read billing period to yield the usage estimate for the billing period.

3.1.1 TIME-OF-USE AND SEASONAL ESTIMATION (kWh):

If the rate for the estimated billing period is a time-of-use rate and sufficient time-of-use history does not exist for a customer or premise, on-peak energy usage is allocated as follows:

	Super Summer (Jun, Jul, Aug) ET-SP Only	Summer (May through October)	Winter (November through April)
Residential			
ET-1	-	40%	30%
ET-2	-	25%	16%
ET-SP			
Super Peak	12%	~~25%~~	~~8%~~
On-Peak (12-3, 6-7)	~~14~~13%	~~25%~~	~~11%~~
~~Total~~ Onff-Peak (12-7)	~~12~~25	25%	~~16~~9%
ECT-1R	-	40%	30%
ECT-2	-	23%	16%
Non-Residential			
All	-	~~40~~32%	~~30~~31%

NOTE: The percentages specified above will also apply for seasonal estimation of Customer-owned on-site distributed generators to include both the energy consumed by the Customer and any excess energy purchased by the utility.

Seasonal on-peak energy percentages listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater then 5%.

3.1.2 ENERGY ESTIMATION FOR CUSTOMER-OWNED ON-SITE DISTRIBUTED GENERATORS

For energy estimation for Customer-owned on-site distributed generators, the following hierarchy is used: 1) The estimate will be based on each generators previous month's energy output unless that month was an initial bill. 2) If the

prior month's generator-specific energy output is not available or was an initial bill, the estimate will be based on the generator-specific energy output for the same month in the prior year. 3) If the generator-specific prior month or same month last year energy output is unavailable but adequate seasonal history exists for a similar type of generator, energy output will be estimated based on the similar generator's output during six months of the same season. 4) If similar generator output is not available, the estimate will be based on the prior month's generation output at that premise unless that month was an initial bill. 5) If prior month's premise generator output is not available or was an initial bill, the premise generator output for the same month in the prior year will be used to estimate generator output. 6) If premise-specific prior month or same month last year generator output is unavailable but adequate seasonal premise generation output history exists, energy output will be estimated based on daily generation output during six months of the same season. 7) When adequate Customer or similar generator output history is not available, the generator estimate is based on a 50% availability factor for the month (20% for PV systems).

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak energy consumption.

3.1.3 EXCESS POWER (ENERGY) ESTIMATION FOR CUSTOMERS WITH CUSTOMER-OWNED ON-SITE DISTRIBUTED GENERATORS

This section estimates the amount of Customer-owned on-site distributed generation energy provided to the APS distribution system ("Excess Power"). For Excess Power estimation for Customer-owned on-site distributed generators, the following hierarchy is used: 1) The estimate will be based on the previous month's Excess Power kWh level unless that month was an initial bill. 2) If the prior month's Excess Power kWh level is not available or was an initial bill, the estimate will be based on the Excess Power kWh level for the same month in the prior year. 3) If the Excess Power kWh level for the prior month or same month last year is unavailable but adequate seasonal Excess Power history exists, the Excess Power kWh level will be estimated based on the daily Excess Power kWh level during six months of the same season. 4) If the seasonal daily Excess Power kWh level is not available, the Customer's estimate will be based on the prior month's Excess Power kWh level at that premise unless that month was an initial bill. 5) If prior month's premise Excess Power kWh level is not available or was an initial bill, the premise Excess Power kWh level for the same month in the prior year will be used to estimate the Excess Power kWh level. 6) If premise-specific prior month or same month last year Excess Power kWh level data is unavailable but adequate seasonal premise Excess Power kWh level history exists, the Excess Power kWh level will be estimated based on the daily Excess Power kWh level during six months of the same season. . 7) When adequate Customer or similar Excess Power kWh level history is not available, the Excess Power kWh level estimate is based on the following formula:

a. Residential PV Systems: (1,630.8 x the nameplate continuous output power rating of the generating facility)/12 x .10
b. All other generating systems will be addressed on a case-by-case basis

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak Excess Power kWh levels.

3.2 DEMAND ESTIMATION

For those accounts where the missing read period is billed on a demand rate and the missing read billing period is not for an initial bill, demand is estimated using the following hierarchy:

3.2.1 If it is the same customer, use the prior month's demand unless that demand was estimated or is for an initial bill.

3.2.2 If it is the same customer, but the prior month's customer-specific demand is not available or was estimated or was an initial bill, use the customer-specific demand read from the same billing month a year ago, unless that demand was estimated or is for an initial bill.

3.2.3 If the bill for the same month of the prior year was not for the same customer, or was estimated or for an initial bill, use the premise demand read for the prior month, unless that demand was estimated or is for an initial bill.

3.2.4 If the prior month's premise demand was estimated or was an initial bill, use the premise demand read from the same billing month of the prior year, unless that demand was estimated or was for an initial bill.

3.2.5 For purposes of this Section 3.2., a demand read is considered "estimated" if the demand was not reset the prior month (or any time thereafter) and the demand read is not greater than the prior month's demand read which was not reset.

3.2.6 If none of the above is applicable, apply the rate schedule load factor percentage to the appropriate kWh. The rate schedule load factor percentages are:

Residential:	Load Factor %
~~EC-1~~	~~35%~~
ET-SP Super-Peak	43%
ET-SP On-Peak	38%
ECT-1R	42%
ECT-2	~~46~~39%
Non-residential:	
All	50%

Load factors listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater than 5%.

3.2.7 From time to time, meter reader may be unable to reset demand readings. When this occurs the readings are noted as "Demand Not Reset."

3.2.7.1 In the month when the "Demand Not Reset" is noted, the kWh and kW are not estimates and are used for billing purposes.

3.2.7.2 In the following month, if the meter reader is able to reset the demand, the "Demand Not Reset" notation is removed.

1) If the kW reading is less than the reading for the previous month, the demand is used for billing purposes and is not an estimated demand.

2) If the demand reading is greater than the previous month when the "Demand Not Reset" was noted, the read demand is used.

3) If the demand reading is equal to the demand reading when the "Demand Not Reset" was noted, demand will be estimated using the procedures described in previous sections of this schedule.

3.2.8 DEMAND ESTIMATION FOR CUSTOMER-OWNED DISTRIBUTED GENERATORS

For those accounts where the missing read period is billed on a demand rate and the missing read billing period is not for an initial bill, demand is estimated using the following hierarchy:

3.2.8.1 If it is the same customer, use the prior month's demand from the Customer-owned generator unless that demand was estimated or is for an initial bill.

3.2.8.2 If it is the same customer, but the prior month's customer-specific demand from the generator is not available or was estimated or was an initial bill, use the customer-specific demand on the generator from the same billing month a year ago, unless that demand was estimated or is for an initial bill.

3.2.8.3 If the demand on the generator for the same month of the prior year was not for the same customer, or was estimated or for an initial bill, use the premise generator demand read for the prior month, unless that demand was estimated or is for an initial bill.

3.2.8.4 If the prior month's premise demand from the generator was estimated or was an initial bill, use the premise demand from the generator from the same billing month of the prior year.

3.2.8.5 For purposes of this Section 3.2., a demand read on the generator is considered "estimated" if the demand was not reset the prior month (or any time thereafter) and the demand read on the generator is not greater than the prior month's demand read which was not reset.

3.2.8.6 If none of the above is applicable, apply the rate schedule load factor percentage to the appropriate kWh. The rate schedule load factor percentages are:

Residential:	Load Factor %
ET-SP Super Peak	43%
ET-SP On-Peak	38%
ECT-1R	42%
ECT-2	39%
Non-residential:	
All	50%

Load factors listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater than 5%.

3.2.8.7 From time to time, meter reader may be unable to reset demand readings. When this occurs the readings are noted as "Demand Not Reset."

3.2.8.7.1 In the month when the "Demand Not Reset" is noted, the kWh and kW are not estimates and are used for billing purposes.

3.2.8.7.2 In the following month, if the meter reader is able to reset the demand on the generator, the "Demand Not Reset" notation is removed.

1) If the kW reading is less than the reading for the previous month, the demand on the generator is used for billing purposes and is not an estimated demand.

2) If the demand reading on the generator is greater than the previous month when the "Demand Not Reset" was noted, the read demand is used.

3) If the demand reading is equal to the demand reading when the "Demand Not Reset" was noted, demand will be estimated using the procedures described in previous sections of this schedule.

3.3 INITIAL BILL

An initial bill is the first bill a customer receives for a premise. Examples of an initial bill include a new meter set where no service has previously been provided, or a previously occupied premise that is now in the new connecting customer's name.

If the billing period for an initial bill is fewer than 11 days and no read was obtained, the customer is billed only a daily basic service charge, and any energy used during this period is included in the following month's billing period usage. If the billing period is 11 or more days, the bill is estimated as follows:

3.3.1 ENERGY USAGE (kWh):

If there is no usage history for the premise, a "minimum usage" estimate is multiplied by the number of days in the missing read billing period. The difference in energy used during this period and the "minimum usage" estimate is included in the following month's billing period usage. The "minimum usage" estimates for total kWh are:

Residential:	
E-12 ~~and E-10~~	~~23~~ 25 kWh per day
~~EC-1~~	~~55 kWh per day~~
ET-1 and ET-2	~~41~~ 47 kWh per day
ET-SP	47 kWh per day
ECT-1R and ECT-2	~~66~~ 75 kWh per day
Non-residential:	
Under 20 kW	45 kWh per day
Over 20 kW	1,156 kWh per day

NOTE: The minimum usage estimates specified above also apply to energy consumed by the Customer under rate schedules EPR-2 and EPR-5. Excess energy purchased by the utility will be estimated at zero for the initial bill.

Initial bill minimum energy usage estimates for total kWh listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater then 5%.

If there is usage history for the premise, energy will be estimated using the applicable method in Section 3.1. If there is no on-peak usage history for the premise, the allocations found in Section 3.1.1 will be utilized.

3.3.2 DEMAND (kW):

For those accounts where the missing read period is billed on a demand rate, demand is estimated as follows:

For initial bills fewer than 11 days, no demand charge is billed.

For initial bills 11 or more days, the kW is estimated using the same hierarchy as indicated in Section 3.2.

3.4 ADVANCED METER INFRASTRUCTURE (AMI) METERS

When a missing read occurs on an account with an AMI meter, an initial attempt to estimate will be performed using partial month data as available. AMI meter data is normally collected on a daily basis, and therefore would be used to compute an estimate for the billing month, even if some of these daily reads are missing.

3.4.1 For initial and normal bills ~~of 11-24 days~~:

If the latest AMI meter data is available with a meter reading of 11 or more days since the last read date for the previous billing month:

1) Review the daily AMI incremental reads to determine the total energy consumption, on-peak percentage and demand for the billing month. Use reads from the latest AMI data to determine a per-day usage value and multiply by the number of days in the current billing period to yield the estimates for total and on-peak usage.

2) If the AMI meter data is unavailable use the estimation methods for non-AMI meters.

3.4.2 For initial and normal bills of 10 or less days, use the estimation methods described in Section 3.3.

3.5 DEAD OR FAILING METER

For accounts where it is determined the meter is dead or failing, no adjustment to the bill will be made until the new meter is in place at least 11 days. Then the usage for the previous month(s) is to be determined by taking the lower of the per day usage calculated from the new meter, less 3% (plus 3% for estimating customer-owned on-site generation bought by Utility), or the Same Month Prior Year Method described in Section 3.1. Charges for underbillings of dead or failing meters will be limited to three months for residential accounts and six months for non-residential accounts, in accordance with Schedule 1 Section 4.3. In instances where Company believes the customer's usage patterns were different during the dead or failing meter period than those being used to estimate, Company may adjust its estimate downward from either method.

3.6 ENERGY DIVERSION OR METER TAMPERING

In instances where energy diversion or meter tampering has occurred, meter reads from the ~~customer's~~ meter will not accurately reflect all of the energy usage. Energy consumption for the period during which the diversion or meter tampering occurred shall be estimated by calculating a per day usage based on the best available information. This may include 1) metered data obtained from an auxiliary meter installed during the diversion investigation; 2) meter information obtained from the customer's meter after the diversion or meter tampering was discovered by Company and stopped; and 3) consumption history for the customer or site prior to when the diversion or meter tampering began.

In some instances, the estimated consumption based on per day usage may be less than what the ~~customer's~~ meter actually registered during the time period. In those cases, the actual usage will be used in the calculation of the total energy diversion or meter tampering back bill.

3.7 NON-CUSTOMER INFORMATION SYSTEM ESTIMATES

In some instances, an account is coded to not be automatically estimated by Company's Customer Information System (CIS). This occurs when, due to special circumstances of the account (such as: served at substation voltage, receives a power allowance from a

federal agency, partial requirements/self-generation, etc.), manual intervention in the billing process is required. For those accounts which are coded to not be automatically estimated by the CIS, additional attempts may be made to obtain meter readings which will be used for billing. If reads are not obtained, then energy and demand will be estimated, using the applicable methods described in this Schedule.

3.8 REBILLS OF PREVIOUS ESTIMATES

In instances where the reads from the previous month are estimated and a subsequent actual read is obtained, the following "true-up" is performed.

3.8.1 ENERGY USAGE

If the actual read following an estimated read is either lower than the estimated read, or, in Company's opinion, considerably higher than the previously estimated read(s), then per day usage is calculated using the difference in kWh between the last actual read and the current month actual read. The per day usage is multiplied by the number of days in each estimated month and each affected month is rebilled using the new per day usage kWh.

3.8.2 DEMAND

If the actual demand read obtained after an estimate is lower than the estimated demand read, the previous month(s) estimated demand read(s) are lowered to the subsequent actual demand read.

The estimates used in this Section 3.8 take precedence over the estimating methods described elsewhere in this Service Schedule.

APS

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AUG 11 2009
AZ CORP COMM
Director Utilities

August 11, 2009

Docket Control
Arizona Corporation Commission
1200 west Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY ADDITIONAL SUPPLEMENTAL DIRECT TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT
DOCKET NO. E-01345A-08-0172

Attached is Additional Supplemental Direct Settlement Testimony of Arizona Public Service Company witness David J. Rumolo. This testimony supplements the Direct Settlement Testimony that was previously filed on July 1, 2009 in this matter.

Sincerely,

Leland R. Snook

LS/dst

Attachments

CC: Brian Bozzo
Terri Ford
Barbara Keene
Parties of Record

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EXHIBIT
APS 15
ADMITTED

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This 11 day of August 2009 to:

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ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY

OF DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

August 11, 2009

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ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY OF DAVID J. RUMOLO

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David J. Rumolo. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. ARE YOU THE SAME DAVID J. RUMOLO WHO PREVIOULSY FILED DIRECT TESTIMONY IN SUPPORT OF ARIZONA PUBLIC SERVICE COMPANY'S APPLICATION, DIRECT SETTLEMENT TESTIMONY, AND SUPPLEMENTAL TESTIMONY IN THIS DOCKET?

A. Yes, I filed Direct Testimony in support of Arizona Public Service Company's ("APS" or "Company") application for rate relief, Direct Settlement Testimony in support of the proposed Settlement Agreement ("Agreement") and Supplemental Testimony.

Q. WHAT IS THE PURPOSE OF YOUR ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY?

A. My Direct Settlement Testimony discussed the Plan of Administration ("POA") for the Demand Side Management Adjustment Charge (DSMAC) and the POA for the Power Supply Adjustment ("PSA"). The proposed Agreement rate schedules and service schedules were filed in this docket for review and comment. APS has received comments on the DSMAC POA and the PSA POA from the Staff of the Arizona Corporation Commission ("Staff"). Staff comments have been incorporated into the respective POAs.

My Additional Supplemental Testimony also provides a revised proposed line extension policy, Service Schedule 3. This revised policy incorporates comments APS has received from Staff.

II. PLANS OF ADMINISTRATION

Q. HAS APS DEVELOPED A REVISED DSMAC POA AND PSA POA?

A. Yes, the revised DSMAC POA and supporting schedules are attached to this Additional Supplemental Testimony and marked Attachment DJR-3-S (Supplemental). Similarly, the PSA POA has been attached and marked Attachment DJR-4-S(Supplemental).

Q. ARE THE CHANGES TO THE PLANS OF ADMINISTRATION SUBSTANTIVE?

A. No, they are primarily editorial and provide further clarification as to the mechanical aspects of the plans.

III. SERVICE SCHEDULE 3

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO PREVIOUSLY FILED DOCUMENTS?

A. Yes. Attachment DJR-5-S(Supplemental) consists of a revised proposed Service Schedule 3 which is the APS line extension policy. The revisions consist of language changes suggested by Staff that capture language found in the Agreement. We have also eliminated the Statement of Charges that were proposed for 2011 and 2012. The Statement of Charges for 2010 will be effective until the next APS general rate case.

Q. DOES THIS CONCLUDE YOUR ADDITIONAL SUPPLEMENTAL DIRECT SETTLEMENT TESTIMONY?

A. Yes.

DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE PLAN OF ADMINISTRATION

2009-~~0608~~-~~2~~11

1. GENERAL DESCRIPTION:

This document describes the plan for administering the Demand Side Management Adjustment Charge ("DSMAC") approved for Arizona Public Service Company ("APS") by the Arizona Corporation Commission ("Commission") in Decision No. 67744, and later revised by the Commission in Decision No. XXXXX. The DSMAC provides for the recovery of Demand Side Management ("DSM") program costs, including energy efficiency and demand response programs, and energy efficiency performance incentives. The DSMAC is applied to Standard Offer or Direct Access customer's bills as a monthly ~~kilowatt~~ kilowatt-hour charge (for Residential customers and General Service customers served in accordance with non-demand billed rate schedules) or kilowatt demand charge (for General Service customers served in accordance with demand billed rate schedules). The charge will be filed with the Commission annually when APS submits the Energy Efficiency Implementation Plan ("EEIP") for approval. This will occur July 15, 2009 for the 2010 program year, and on June 1st of all subsequent years. If approved by the Commission, the charge will be effective each year beginning with billing cycle 1 of the March revenue month and will not be prorated.

Recovery of all applicable programs costs and incentives will be allowed for all programs that have been approved by the Commission.

2. RATE SCHEDULE APPLICABILITY:

The DSMAC shall be applied monthly to every ~~retail Standard Offer or Direct Access service, unless otherwise noted in any rate schedule~~ retail Standard Offer or Direct Access service with the exception of customers served on rate schedules E-5 and E-4, and solar rate Solar-2.

3. ALLOWABLE COSTS:

The types of allowable costs are as follows:

A. Program Costs (PC)

Allowable expenses include, but are not limited to:
Program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self direction costs, measurement evaluation and research (MER), demonstration facilities and all other activities required to design and implement ~~cost~~ cost-effective DSM programs (energy efficiency and demand response) that are approved ~~or are pending approval~~ by the Commission in the EEIP. For those DSM programs that generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be an allowed program expense.

B. Performance Incentives (PI)

Represents a percentage share of the net economic benefits (benefits minus costs) from approved ~~and pending~~ energy-efficiency programs based on a graduated scale that is capped at a percentage of PC.

4. DETERMINATION OF TRUE-UP:

The actual allowable cost recovered for approved DSM programs will be compared to the actual revenues received by the Company through the DSMAC. The True-Up (TU) will be based on the amount in the TU balancing account. This balance will include past period PC, PI and DSMAC revenue collection accruals as of April 30th of the filing year. Past period PC and PI are found on Schedule 2 of the DSMAC calculations. Past period DSMAC revenue ~~are~~ is found in Schedule 1 of the DSMAC calculations. The TU balancing account computation will be provided annually in Schedule 3 of the DSMAC calculations.

DEMAND SIDE MANAGEMENT ADJUSTMENT CHARGE PLAN OF ADMINISTRATION 2009~~-0608-24~~11

In the event that PC or PI are more or less than DSMAC revenues collected as of ~~April 30th~~ the last billing cycle of February, the over or under collection will be subtracted from or added to the DSMAC calculation in the subsequent period. Any over collection will accrue interest charges. Under collections will not accrue interest.

Illustrative Table of Events

Date	Included Items
7/15/2009 DSMAC includes:	File 2010 EEIP with 2010 DSMAC 2010 forecast of PC and PI 2009 forecast of PC and PI TU balancing account as of the last billing cycle of February ~~4/30/2009~~
3/1/2010	DSMAC start from 2010 EEIP
6/1/2010 DSMAC includes:	File 2011 EEIP with 2011 DSMAC 2011 forecast of PC and PI TU balancing account as of the last billing cycle of February ~~4/30/2010~~
3/1/2011	DSMAC start from 2011 EEIP
6/1/2011 DSMAC includes:	File 2012 EEIP with 2012 DSMAC 2012 forecast of PC and PI TU balancing account as of the last billing cycle of February ~~4/30/2011~~

5. DETERMINATION OF THE ADJUSTOR CHARGE:

By July 15, 2009 and on June 1st of each subsequent year, APS will file a revised DSMAC with supporting documentation in the EEIP. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods. This calculation will be provided in the annual DSMAC calculation on Schedule 4.

The DSMAC for purposes of recovering PC and PI under the DSM Program will be developed based on the following formula:

$$DSMAC = \frac{PC + PI + TU + I}{Sales}$$

Where:

PC	=	Program Costs as defined in section 3 forecast for the upcoming year.
PI	=	Performance Incentives as defined in section 3 forecast for the upcoming year.
TU	=	Any "true-up" balance as defined in section 4.
I	=	Interest associated on any over recovery of DSMAC costs for the prior period. The interest rate is based on the one-year Nominal Treasury Maturities rate from the Federal Reserve H-15 or its successor publication. The interest rate shall be adjusted annually on the first business day of the calendar year.
Sales	=	Forecast energy (kWh) sales under applicable electric rate schedules during the Adjustor Period in which this adjustor will be effective.

Adjustor Period = The 12 month period beginning with the first billing cycle during March of the current year and ending with the last billing cycle of February of the next year.

The DSMAC for General Service customers that are billed on demand will be calculated as a per kW charge. The DSMAC for General Service customers that are not billed on demand will be calculated as a per kWh charge. To calculate the per kW charge, the recoverable costs shall first be allocated to the General Service class based upon the number of kWh consumed by that class. The remainder of the recoverable costs allocated to the General Service class shall then be divided by the kW billing determinants for the demand billed customers in that class to determine the per kW DSMAC.

For residential billing purposes, the DSMAC and the Renewable Energy Surcharge ("RES") ~~adjustor~~ are combined and will appear on customer bills as the "Environmental Benefits Surcharge". For the billing of general service and other non-residential customers, the Company may, but is not required to, provide for such combined billing of the RES and DSMAC. In any event, each adjustor shall have separate rate schedules and will be kept separate in the Company's books, records, and reports to the Commission.

6. REVIEW PROCESS:

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Section 4. APS will file an updated adjustor charge each year with its EEIP. The first filing will be July 15, 2009, and June 1st each year thereafter. If approved by the Commission, changes in the DSMAC will go into effect on the first billing cycle of March in the Adjustor Period.

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM
DSMAC REVENUE AND EXPENSE BY MONTH

Line No.	True-Up Period[1]	(A) 3/31/20xx	(B) 4/30/20xx	(C) 5/31/20xx	(D) 6/30/20xx	(E) 7/31/20xx	(F) 8/31/20xx	(G) 9/30/20xx	(H) 10/31/20xx	(I) 11/30/20xx	(J) 12/31/20xx	(K) 1/31/20xx	(L) 2/28/20xx
1	Beginning Balance[2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	True-Up Balance[3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Actual Costs[4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Non-Demand Billed kWh	-	-	-	-	-	-	-	-	-	-	-	-
5	Demand Billed kW	-	-	-	-	-	-	-	-	-	-	-	-
6	$/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	$/kW	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	DSMAC Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Ending Balance[6]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

[1]True-Up Period reflects the charge period of March 20xx - February 20xx.

[2]Beginning Balance column A reflects the total amount of money spent January and February of 20xx over the amount collected in base rates. For the first few years this may be slightly different to reflect the change of a historical DSMAC to a more concurrent DSMAC.

[3]True-Up Balance column A reflects the amount of dollars that were to be collected or credited during the true-up period.

[4]Actual Costs reflects the actual program costs during that period.

[5]Line 8 = Line 4 * Line 6 + Line 5 * Line 7

[6]Line 9 = Line 1 + Line 2 + Line 3 - Line 8

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

FORECAST PROGRAM COSTS AND INCENTIVES
FOR PROGRAM YEAR 20xx

Line No.	Program	Reference	Program Costs Forecast 20xx[1][2]
1	Energy Efficiency (EE) Program Costs (PC)		$ -
2	Performance Incentives (PI)		$ -
3	Sub Total	(Line 1 + Line 2)	$ -
4	Demand Response (DR) PC		$ -
5	Total	(Line 3 + Line 4)	$ -

[1]This is the forecast cost for EE PC, PI and DR PC based on the 20xx Implementation plan, less the amount to be collected in base rates.
[2]For the first filing this will reflect two years of forecast costs as we move from a historical DSMAC to a more concurrent DSMAC

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

TRUE-UP (TU) BALANCING COMPUTATION

Line No	Date Period	Cost, Collection and Interest	Reference	Amount
1	2/28/20xx	True-Up Period Ending Balance	Schedule 1, Line 9, Column L	$ -
2	Treasury constant maturities rate 1/2/2009[1]	Interest = 0.4%	(Line 1 * Interest Rate)	$ -
3		Total TU Balance	(Line 1 + Line 2)	$ -

[1]Interest is only applied to over-collections.

ARIZONA PUBLIC SERVICE COMPANY
DEMAND SIDE MANAGEMENT PROGRAM

DSMAC CALCULATION
FOR
MARCH 1, 20xx THROUGH FEBRUARY 28, 20xx

Line No.	DSMAC Calculations	Reference		Amount	Units
1	Program forecast costs for adjustor period in 20xx	Schedule 2, Line 5	$	-	
2	True-Up Balance	Schedule 3, Line 3	$	-	
3	Total amount to be collected	(Line 1 + Line 2)	$	-	
4	Forecast retail kWh sales for adjustor period[1]			-	kWh
5	Proposed kWh adjustor charge for adjustor period[2]	(Line 3 / Line 4)	$	-	per kWh
6	Forecast General Service kWh sales for adjustor period[3]			-	kWh
7	Amount to be collected from General Service demand metered customers for adjustor period	(Line 5 * Line 6)	$	-	
8	Forecast General Service demand metered customer kW			-	kW
9	Proposed kW adjustor charge for forecast period[4]	(Line 7 / Line 8)	$	-	per kW

[1]Forecast retail kWh sales excludes E-3 and E-4 kWh.
[2]$/kWh charge for all Residential customers and General Service customers with no demand charge.
[3]Forecast General Service kWh for customers with demand charges.
[4]$/kW charge for General Service customers with demand charges.

Power Supply Adjustment
Plan of Administration

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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 amended by the Commission on XXXXX in Decision No. XXXXX. The PSA provides for the recovery of fuel and purchased power costs, to the extent that actual fuel and purchased power costs deviate from the amount recovered through APS' Base Cost of Fuel and Purchased Power ($0.037571 per kWh) authorized in Decision No. XXXXX, from January 1,2010. It also provides for refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base rate amount of (($0.000242) per kWh)[1].

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and margins on the sales of emission allowances ("~~Deferrable~~PSA Costs") to set a rate that is then reconciled to actual costs experienced. This PSA includes a 90/10 sharing mechanism under which APS absorbs 10 percent of the deviations between actual fuel and purchased power costs and the amount recovered through base rates. The demand component of long-term purchased power agreements (duration of three years or longer) acquired via a competitive procurement process, renewable energy costs not recovered through other mechanisms, and net margins from the sales of emission allowances are exempt from the 90/10 sharing. This PSA includes a limit of $0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year. This PSA also provides a mechanism for mid-year rate adjustment 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,

[1] *($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 mWh)/1000*

prudently incurred ~~Deferrable~~PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) ~~deferrable~~PSA Ceosts and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
   a. The opportunity to seek a mid-year change in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission deem such an adjustment to be appropriate.
   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~~n~~ Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a proposed calculation of the three components of the PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) ~~deferrable~~PSA ~~costs~~ Costs embedded in base rates and (2) the ~~forecasted~~forecast ~~deferrable~~PSA ~~costs~~ Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its ~~deferrable~~PSA ~~costs~~Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the ~~forecasted~~forecast costs by the ~~forecasted~~forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base ~~Deferrable~~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' over/under-recovery of its actual ~~deferrable~~PSA ~~costs~~ Costs as compared

[1] *($0.000242) per kWh is the result of the following: (Normalized gains from SO2 allowances of ($7,044,934))/(ACC jurisdictional test year sales of 29,133,753 mWh)/1000.*

to the Base ~~Deferrable~~PSA Costs recovered in revenue. The over/under-recovery of costs is divided into two separate calculations to allow the application of the 90/10 sharing mechanism on those costs to which it applies. 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 3 1 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 ~~forecasted~~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 September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[1]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September 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 December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision, if necessary, is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[2]

[1] For example, the September 30, 2008 filing would include actual balances for February through August of 2008 and estimated balances for September 2008 through January 2009.

[2] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

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 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 future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to 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.

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 September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

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 (as amended by the updated December 31 filing) 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. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of ~~Solar-1,~~ Solar-2~~, SP-1~~, E-3, E-4, E-36, 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. September 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 September 30 of each year. That calculation shall use a forecast of kWh sales and of ~~deferrable~~PSA ~~costs~~ 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.[3]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. 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.[4]

c. 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.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall

[3] 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.

[4] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the PSA.

be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

5. Verification and Audit

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 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 - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Base ~~Deferrable~~PSA Costs- An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost and net margins from the sales of emission allowances embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base ~~Deferrable~~PSA Costs recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.037571 per kWh effective on January 1, 2010.

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' most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at (($0.000242) per kWh) effective on January 1, 2010.

~~Deferrable~~PSA Costs- The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus the N~~n~~et M~~m~~argins on the S~~s~~ales 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 ~~forecasted~~forecast ~~deferrable~~PSA ~~costs~~ Costs generally expressed as a rate per kWh less the Base ~~Deferrable~~PSA Costs generally expressed as a rate per kWh embedded in APS' 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' over/under-recovery of its actual ~~deferrable~~PSA ~~costs~~ Costs as compared to the actual Base

~~Deferrable~~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; 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.

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 includes customer load in the APS control area for which APS has a generation service obligation and 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.

PSA - The Power Supply Adjustment mechanism approved by the Commission in Decision No. ~~69633~~69663 and amended by the Commission in Decision No. XXXXX, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of ~~deferrable~~PSA ~~costs~~ Costs that are eventually reconciled to actual costs experienced. This PSA allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

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

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

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, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. ~~69633~~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' 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 Effective February 1, 20~~0~~10
Schedule 2	PSA Forward Component Rate Calculation Effective February 1, 2010
Schedule 3	PSA Year Forward Component Tracking Account (in effect February 1, 2010-January 31, 2011)
Schedule 4	PSA Historical Component Rate Calculation Effective February 1, 2010
Schedule 5	Historical Component Tracking Account (in effect February 1, 20~~0~~10-January 31, 2011)
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account (in effect XX 1, 20XX-XX 31, 20XX)

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in the Company'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~~b~~. Customer sales in both MWh and thousands of dollars by customer class.
    d~~e~~. Number of customers by customer class.
    e~~d~~. A detailed listing of all items excluded from the PSA calculations.
    f~~e~~. A detailed listing of any adjustments to the adjustor reports.
    g~~f~~. Total off-system sales revenues.
    h~~g~~. System losses in MW and MWh.
    i~~h~~. 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 rate, 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 them, total cost, supply basin, and volume by contract.

E. APS will also provide:

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

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

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, the net margins on the sale of emission allowances 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)

Additionally, broker fees recorded in FERC account 557 are allowable up to the limit set in Decision No. XXXXX.

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 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 are excluded from the PSA.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Power Supply Adjustment (PSA) Rate Calculation Effective February 1, XXXX
($/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, L13)	$ -	$ -	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 September 30 filing and updated in the December 31 filing of 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 Effective February 1, XXXX
($ 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 Net Margins on the Sale of Emission Allowances	-	-	N/A	N/A
6	Projected Billed Native Load Sales, excluding E-3, E-4, E-36 (MWhs) [3]	##,###,###	-	N/A	N/A
7	Projected Average Net Fuel Cost $/kWh (L4 / L6)	#.######	$ -	N/A	N/A
8	Projected Average Margin on Emission Allowances $/kWh (L5 / L6)	$ -	$ -	N/A	N/A
9	Total Projected Average PSA Cost $/kWh (L7+L8)	#.######	$ -	N/A	N/A
10	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh [4]	$ 0.037571	$ -	N/A	N/A
11	Authorized Base Net Margins on the Sale of Emission Allowances Rate $/kWh [4]	$ (0.000242)	$ -	N/A	N/A
12	Total Authorized Base Cost $/kWh	$ 0.037329	$ -	N/A	N/A
13	Forward Component Rate $/kWh (L9 - L12)	#.######	$ -	N/A	N/A

Notes:

[1] Proposed levels are provided in the September 30 filing and updated in the December 31 filing of each year.

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

[3] The Projected Billed Native Load Sales of X,XXX,XXX MWhs for the Current Rate represent forecast sales for XXXX as of December 30th, XXXX. They exclude ED 3 and City of Williams wholesale contracts that are excluded from the Proposed sales and fuel costs.

[4] Base Cost of Fuel and Purchased Power established in Decision No. _____.

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

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

			Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sept-XX	Oct-XX	Nov-XX	Dec-XX	Jan-XX	XXXX Total
1	Prior Month's Balance	*From L31*													
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-3, E-4, E-36 Sales (MWh) [3]														
PSA Costs															
7	Renewables Costs [4]														
8	PPA Fixed Costs														
9	Other Fuel and Purchased Power Costs [5]														
10	Off System Revenue (Credit) [6]														
11	Net Margins on Sale of Emission Allowances														
12	Net PSA Costs	*sum(L7 to L11)*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Retail PSA Costs															
13	Renewables Costs	*L5 * L7*													
14	PPA Fixed Costs	*L5 * L8*													
15	Other Fuel and Purchased Power Costs	*L5 * L9*													
16	Off System Revenue (Credit)	*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	Renewables Recovery	*L32 * L2*													
20	PPA Fixed Recovery	*L33 * L2*													
21	Other Fuel and Purchased Power Recovery	*L34 * L2*													
22	Net Margins on Sale of Emission Allowances	*L36 * L2*													
(Over) Under Recovery From Base Rate															
23	Renewables (Over) Under Recovery	*L13 - L19*													
24	PPA Fixed (Over) Under Recovery	*L14 - L20*													
25	Other Fuel and Purchased Power (Over) Under Recovery	*(L15 + L16) - L21*													
26	Net Margins on Sale of Emission Allowances (Over) Under Recovery	*L17 - L22*													
27	Less 10% Sharing On Other (Over) Under Recovery	*- 0.10 * L25*													
28	Total (Over) Under Recovery	*sum(L23 to L27)*	-	-	-	-	-	-	-	-	-	-	-	-	
29	Interest Accrued on Prior Month's Balance	*L38 * L1*													
30	Forward Component Collections	*- L37 * L6*													
31	Tracking Account Balance	*L1 + L28 + L29 - L30*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

32	Renewable Costs In Base Fuel Rate - ¢ per kWh	0.0672
33	PPA Fixed Costs In Base Fuel Rate - ¢ per kWh	0.1212
34	Other Costs In Base Fuel Rate - ¢ per kWh	3.0607
35	Total Base Fuel Rate - ¢ per kWh	3.2491
36	Base Net Margin on the Sale of Emission Allowances - ¢ per kWh	-0.0242
37	Forward Component Rate - ¢ per kWh	#.####
38	Interest Rate – 2010	#.##%

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 schedule E-36 were excluded from the PSA Calculations.

[2] Includes *traditional* sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. ED 3 and City of Williams energy sales 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 will 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 RES rate schedule.

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

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

[7] Generally, Line 37 * Line 6 = Line 26; however, differences may occur due to billing adjustments.

E-36 Sales	
12,194	
	2,666,474

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

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
PSA Historical Component Rate Calculation Effective February 1, XXXX
($ 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, L31)	#,###	$ -	N/A	N/A
2	Historical Component Tracking Account Balance (Schedule 5, 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-3, E-4 and E-36 (MWh)	##,###,###	-	N/A	N/A
5	Applicable Historical Component Rate (L3 / L4)	#.######	$ -	N/A	N/A

Notes:
[1] Proposed levels are provided in the September 30 filing and updated in the December 31 filing of each year.
[2] Includes remaining balances from the Old PSA Annual Adjustor Account ($(4.3) million) and the July 2007 Surcharge Account ($+2.7 million).

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh 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 Dec. 31, XXXX													
2	Projected FC Tracking Account Balance at Dec. 31, XXXX													
3	True-up from December - 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-3, E-4, E-36 Sales (MWhs) [3]													
8	Less Revenue from Applicable HC (L6 x L7) [4,5]													
9	Monthly Interest ([L5 * L11 / 12])													
10	HC Ending Balance ; (L5 - L8 + L9)	$ -												
11	Interest Rate -- XXXX [5]	#.##%												

Notes:

[1] True-up is the result of using estimated revenue and deferral for December and January since the actual amount was not available at the time of prior period PSA 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.

[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

Schedule presentation will appear to round up to $s and MWh; however, calculations are performed on an actual $ and MWh 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 [1]	Proposed February 1, XXXX [1]	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-3, E-4 and E-36 (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 $s and MWh; however, calculations are performed on an actual $ and MWh 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.		20XX Data January	February	March	April	May	June	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-3, E-4, E-36 Sales (MWhs) [2]			-	-	-	-	-	-	-	-	-	-	-
6	Less Revenue from Applicable Transition Component (L4 x L5) [3]			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest ((L2 * L9 / 12))			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Ending Balance; (L3 - L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Interest Rate [4]	x.xx%												

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

[4] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

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

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

Line No.		XXXX Data												XXXX
		January	February	March	April	May	June	July	August	September	October	November	December	January
	XXXX Forward Component Tracking Account													
1	Beginning Balance													
2	Transfers to XXXX Historical Component Tracking Account													
3	Monthly Interest													
4	Post-Sharing (Over)/Under Collection													
5	Less Revenue from Applicable Forward Component Rate													
6	Ending Balance with Interest (Ln. 1, 2, 3, 4 - Ln. 5)													
	XXXX Historical Component Tracking Account													
7	Beginning Balance													
8	Transfers from XXXX Forward Component Tracking Account													
9	Monthly Interest													
10	Less Revenue from Applicable Historical Component Rate													
11	Ending Balance with Interest (Ln. 7, 8, 9 - Ln. 10)													
12	**Combined Balance (Ln. 6, 11)**													
13	Combined Monthly Interest (Ln. 3, 9)													

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

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-36, ED 3 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-36, ED 3 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-36, ED 3 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, ED 3, 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.

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

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

All facility installations shall 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. All proceeds received for new facility installations, relocations, or upgrades to existing facilities required to provide service under provisions of this schedule shall be booked as Other Electric Revenue.

The following provisons govern the installation of overhead and underground electric facilities to customers or developers whose requirements are deemed by Company to be usual and reasonable in nature.

DEFINITIONS

a. Conduit Only Design means the conduit layout design for the installation of underground Extension Facilities that will be required to serve a project. Extension Facilities are to be installed at a later date when service is requested.

b. Corporate Business & Industrial 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 and/or industrial use.

c. Extension Facilities means the electrical facilities, inclusive of conductors, cables, transformers and meters, installed solely to serve an individual customer, developer, or groups of customers. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to tie the subdivision to APS existing system as well as the Electrical Facilities constructed within the subdivision which would include primary and service lines, transformers, and meters.

d High Rise Development means buildings built with four or more floors, usually using elevators for accessing floors that may consist of either residential or non-residential use or both, such as a high-rise building where the first level is for commercial purposes and the upper floors are residential.

e. Irrigation means water pumping service. Agricultural pumping means water pumping for farms and farm-related pumping used to grow commercial crops or crop-related activity. Non-agricultural water pumping is pumping for purposes other than the growing of commercial crops, such as golf course irrigation or municipal water wells.

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

g. Residential Custom Home "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.

h. 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 construction of residential homes or permanent mobile home sites.

i. Residential Multi-family Development means a development consisting of apartments, condominiums, or townhouses.

j. Residential Single Family means a house, or a mobile home permanently affixed to a lot or site.

k. Statement of Charges means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities. The Statement of Charges is attached to this Service Schedule as Attachment 1. An applicant requesting an extension will be provided a sketch showing the Extension Facilities and an itemized cost quote based on the Statement of Charges or other applicable details. The Statement of Charges is not applicable to Extension Facilities requiring the relocation, modification, or upgrade of existing facilities or for non-residential customers with estimated loads over 3 megawatts, or that require 3,000 kVA of transformer capacity or greater, or special requests involving primary metering, or specialized or additional equipment for enhanced reliability. When the Statement of Charges is not applicable, charges for Extension Facilities shall be determined by the Company based on project-specific cost estimates.

1.0 RESIDENTIAL

1.1 SINGLE FAMILY HOMES

1.1.1 Extension Facilities will be installed to new permanent residential customers or groups of new permanent residential customers. For purposes of this section, a "group" shall be defined as less than four homes. The cost of extending service to applicant will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.1.2 In instances where an applicant requests service directly from a customer-funded extension constructed in accordance with Section 1.1.1 hereof, the initial applicant may be eligible for refund on a pro-rata basis for a portion of the initial extension cost related to the shared Extension Facilities as determined by the Company.

1.1.3 The first applicant connecting to an extension completed under the provisons of this Section will be required to pay a pro-rata share of the cost of the initial extension plus the costs attributable to the applicant's own extension.

1.1.4 In no event shall the total of refund payments made to the initial customer be in excess of the total amount originally paid by the initial customer.

1.1.5 The refund eligibility period shall be five years from the execution date of APS' line extension agreement to the initial applicant.

1.2 RESIDENTIAL SUBDIVISION DEVELOPMENTS

Extension Facilities will be installed to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant signs an extension agreement. The subdivision development plat shall be approved and recorded in the county having jurisdiction. The cost of extending service to applicant will be determined in accordance with the Statement of Charges and shall be paid by the applicant

prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.3 RESIDENTIAL CUSTOM HOME "LOT SALE" DEVELOPMENTS

1.3.1 Extension Facilities will be installed for residential "lot sale" custom home developments in advance of application for service by permanent customers, provided the applicant sign an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.3.2 Extension Facilities will be installed for each permanent customer upon request for service in accordance with Section 1.1 of this service schedule.

1.3.3 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.

1.4 MASTER PLANNED COMMUNITY DEVELOPMENTS

1.4.1 Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by permanent customers, provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.4.2 Extension Facilities will be installed to each subdivided tract within the planned development in advance of application for service by permanent customers in accordance with the applicable sections of this Service Schedule.

1.5 RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

Extension Facilities will be installed to multi-family apartment, condominium or townhouse developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

1.6 HIGH RISE DEVELOPMENTS

1.6.1 APS will provide service to this type of development at one point of delivery and it is the applicant's responsibility to provide and maintain the electrical facilities within the building.

1.6.2 Extensions will be made to High Rise Developments where the residential units are privately owned and either individually metered or master metered in accordance with Section 5.11.

1.6.3 Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

1.6.4 Extension Facilities will be installed to High Rise Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. The charges for Extension Facilities will be determined based on project-specific requirements and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

2.0 NON-RESIDENTIAL

Extension Facilities will be installed for applicants not meeting the definition of Residential or as provided for in Section 2.1, or Section 3.0 of this Schedule. For applicants with estimated loads of less than 3 megawatts or less than 3,000 kVA of transformer capacity, the charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

The charges for Extension Facilities installed for applicants with projected loads of 3 megawatts or greater, or requiring transformer capacity of 3,000 kVA or greater or applicants requiring primary metering or specialized or additional equipment for enhanced reliability will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

2.1 CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

2.1.1 Extension Facilities will be installed for Corporate Business & Industrial Park Developments in advance of application for service by permanent customers provided the applicant signs an extension agreement. For applicants with estimated loads of less than 3 megawatts or less than 3,000 kVA of transformer capacity, the charges for Extension Facilities will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant.

The charges for Extension Facilities installed for applicants with projected loads of 3 megawatts or greater, or requiring transformer capacity of 3,000 kVA or greater or applicants requiring primary metering or specialized or additional equipment

for enhanced reliability will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to pay the estimated cost of the material or equipment.

2.1.2 Extension Facilities will be installed to individual lots (applicants/customers) within the Corporate and Business Park Development in accordance with the applicable sections of this Service Schedule.

3.0 OTHER CONDITIONS

3.1 IRRIGATION CUSTOMERS

Extension Facilities will be installed for Irrigation Customers provided the applicant signs an extension agreement. The charges for Extension Facilites will be determined in accordance with the Statement of Charges and shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the extension agreement is executed by the applicant. Non-agricultural irrigation pumping service to permanent customers will be extended as specified in Section 2. Non-agricultural irrigation pumping service to temporary or doubtful permanency customers will be extended as specified in Section 3.2 or 3.3 below, as applicable.

3.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the applicant, the applicant shall make a payment in advance of installation or construction equal to the cost of installing and removing the facilities required to provide service, less the salvage value of such facilities. Charges will be in accordance with a cost estimate determined by the Company based on project-specific requirements. Payment is due at the time the extension agreement is executed by the applicant.

When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

3.3 MUNICIPALITIES AND OTHER GOVERNMENTAL AGENCIES

Relocation of existing facilities and/or Extension Facility installations required to serve the loads of municipalities or other governmental agencies may be constructed prior to the receipt of an executed extention agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the extension costs in accordance with the applicable sections of this Service Schedule.

4.0 UNDERGROUND CONSTRUCTION

4.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

4.1.1 The extension meets all requirements as specified in Sections 1.0, 2.0, or 3.0.

4.1.2 The customer or applicant(s) provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications. Customer or applicant(s) may hire contractors to perform this work.

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

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

5.0 GENERAL CONDITIONS

5.1 VOLTAGE

All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located. Company may deliver service for special applications of higher voltages with prior approval from Company's Engineering Department, applicant will be required to pay the costs of any required studies.

5.2 POINT OF DELIVERY

5.2.1 For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus riser.

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

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

5.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be conveyed to the Company 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 obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.4 GRADE MODIFICATIONS

If subsequent to construction of electric facilities the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by customer or developer.

5.5 OWNERSHIP

Except for customer-owned facilities, all electric facilities installed in accordance with this Service Schedule will be owned, operated, and maintained by Company.

5.6 MEASUREMENT AND LOCATION

5.6.1 Measurement must be along the proposed route of construction.

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

5.6.3 The extension must be a branch from, the continuation of, or an addition to, the Company's existing distribution facilities.

5.8 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when customer's estimated load will exceed 3,000 kW, Company will 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 Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

5.9 ABNORMAL LOADS

Company, at its option, may make extensions 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 customer will be included in the payment described in previous sections of this Service Schedule.

5.10 UPGRADES, RELOCATIONS AND/OR CONVERSIONS

5.10.1 Company will upgrade, relocate or convert its facilities for the customer's convenience or aesthetics. The cost of upgrades, relocation or conversion will be as determined by the Company by a detailed estimate will be included in the payment described in previous sections of this Service Schedule.

5.10.2 When the relocation of Company facilities involve "prior rights" conditions, the customer will be required to make payment equal to the estimated cost of relocation as determined by the Company by a cost estimate.

5.11 MASTER METERING

5.11.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

5.11.2 Residential Apartment Complexes, Condominiums - Company shall 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 Corporation Commission's Rules and Regulations or the requirements discussed in 5.11.3 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.

5.11.3 Multi-Unit Residential Developments – Company will allow master metering for residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

5.11.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

5.11.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

5.11.4 Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a payment 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 on the basis specified in Section 1. Applicant is responsible for all costs related to the installation of new service entrance equipment.

5.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild, modify, or upgrade existing facilities to meet the customer's added load or change in service requirements. When the applicant authorizes Company to to proceed with contruction of the extension, the payment will be credited to the cost of the extension otherwise the payment shall be non-refundable. Charges for such changes will be in accordance with a cost estimate determined by the Company based on project-specific requirements.

5.13 STUDY AND DESIGN PAYMENT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company an amount equal to the estimated cost of preparation. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant for upon request.

5.14 SETTLEMENT OF DISPUTES

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

5.15 EXTENSION AGREEMENTS

All facility installations or equipment upgrades requiring payment by an applicant or customer shall be in writing and signed by both the applicant or customer and Company.

5.16 ADDITIONAL PRIMARY FEED

When specifically requested by an applicant or customer to provide an alternate primary feed (excluding transformation), Company will perform a special study to determine the feasibility of the request The applicant or customer will be required to pay for the added cost as well as the applicable rate for the additional feed requested. Installation cost will be based on a cost estimate based on project-specific requirements. Payment for the installation of facilities is due at the time the facilties agreement is executed by the applicant.

5.17 POLICY EXCEPTION

The Schedule 3 as stated herein is applicable to all applicants and customers unless specific exemptions are approved by the Arizona Corporation Commission. The following exemptions have been approved:

5.17.1 Residential Homes on Native American Land

Extensions for residential homes on Native American Reservations will be made in accordance with the provisions of Service Schedule 3 that was in effect April 1, 2005 through June 30, 2007. Application of this Section 5.17.1 is limited to Native American Reservations as defined by applicable Federal law.

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

ATTACHMENT I
SCHEDULE OF CHARGES

Year 2010

Category								
Feeder	Overhead	Underground						
	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
Three Phase	$34.33	$24.73	$3,637	$8,447	$47.05	$6,284	$12,036	$14,422

Primary	Overhead	Underground		
	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Switch Gear
Single Phase	$15.32	$5.75	$719	$3,770
Three Phase	$21.98	$16.66	$1,284	$14,422

	SES Size	Transformer Size	Overhead	Padmount
Transformer Single Phase	200 Amp	25kVA	$3,324	$3,393
	200 Amp	50kVA	$4,160	$4,740
	400 Amp	50kVA	$4,160	$4,740
	600 Amp	75kVA	$5,633	$5,649
	800 Amp	100kVA	$7,152	$6,754

	SES Size	Overhead				Padmount			
		120/208 Volts		277/480 Volts		120/208 Volts		277/480 Volts	
Transformer Three Phase	200 Amp	3-25kVA	$8,839	3-50kVA	$9,053	112.5kVA	$3,848	112.5kVA	$13,277
	400 Amp	3-50kVA	$11,349	3-75kVA	$11,033	112.5kVA	$3,848	225kVA	$15,841
	600 Amp	3-50kVA	$11,349	3-100kVA	$11,545	150kVA	$14,882	300kVA	$17,823
	800 Amp	3-75kVA	$15,753			225kVA	$15,892	500kVA	$19,870
	1000 Amp	3-75kVA	$15,753			225kVA	$15,892	500kVA	$19,870
	1200 Amp	3-100kVA	$20,112			300kVA	$18,413	750kVA	$25,397
	1600 Amp	3-167kVA	$23,638			500kVA	$21,843	1000kVA	$25,642
	2000 Amp					500kVA	$21,843	1000kVA	$25,642
	2500 Amp					750kVA	$23,415	1500kVA	$39,086
	3000 Amp					750kVA	$23,415	1500kVA	$39,086

Meters & Services	Single Phase	Service Line per Circuit Foot		Meter Cost
		Overhead	Underground	
Res & Non-Res	200 Amp	$4.57	$2.79	$224
Residential	400 Amp	$8.58	$3.27	$224
Non-Residential	400 Amp	$8.58	$3.27	$909
Res & Non-Res	600 Amp	$17.16	$6.54	$925
Res & Non-Res	800 Amp	$25.74	$9.87	$925

Meters & Services	Three Phase	Service Line per Circuit Foot		Meter Cost
		Overhead	Underground	
	200 Amp	$3.43	$5.10	$356
	400 Amp	$9.40	$10.18	$1,033
	600 Amp	$14.88	$11.42	$1,057
	800 Amp	$14.88	$25.32	$1,057
	1000 Amp	$29.76	$25.32	$1,094
	1200 Amp	$29.76	$31.65	$1,122
	1600 Amp	$29.76	$50.64	$1,138
	2000 Amp		$50.64	$1,138
	2500 Amp		$82.31	$1,180
	3000 Amp		$88.62	$1,180

Footnotes

1) 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 of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000 amps

2) Extension Facilities that do not qualify for using the Statement of Charges will be determined by a project specific cost estimate

3) Transformer cost for single family homes, residential subdivisions and multi-family projects will be determined by the transformer size indicated above for the "Transformer Single Phase" category

4) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Footage for each circuit will be summed to determine charges

5) Meter costs will be calculated by summing each meter required when multiple meter sockets are installed

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED

2009 AUG -6 P 3: 31

AUG 0 6 2009

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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-08-0172 NOTICE OF FILING REPLY SETTLEMENT TESTIMONY OF PETER M. EWEN

On May 11, 2009, the Commission issued a Procedural Order in the above captioned matter that required the supporting parties to submit reply testimony by August 6, 2009. Arizona Public Service Company hereby submits the attached Reply Settlement Testimony of Peter M. Ewen.

RESPECTFULLY SUBMITTED this 6th day of August, 2009.

PINNACLE WEST CAPITAL CORP.
Law Department

Thomas L. Mumaw
Meghan H. Grabel

Attorneys for Arizona Public Service Company

EXHIBIT
APS 16
ADMITTED

ORIGINAL and 13 copies of the foregoing filed this 6th day of August, 2009 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

AND copies of the foregoing emailed or mailed this 6th day of August, 2009 to Parties of Record

Copies of the foregoing emailed or mailed
This 6 day of August 2009 to:

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REPLY SETTLEMENT TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

August 6, 2009

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REPLY SETTLEMENT TESTIMONY OF PETER M. EWEN ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. **PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am the Chief Economist for Arizona Public Service Company ("APS" or "Company") and manage the Revenue and Fuel Analysis and Forecasts Department for APS. In that role, I am responsible for preparing the Company's economic outlook and corresponding short-range and long-range forecasts of system peak demand and energy sales, as well as projecting the optimal dispatch of available resources to minimize the cost of meeting those energy requirements.

Q. **WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I received Bachelors and Masters degrees in Economics from Arizona State University in 1985 and 1988, respectively. I have analyzed and forecasted electric energy and demand growth since 1988, first as a Staff member of the Arizona Corporation Commission ("Commission") and, since 1990, as an employee for APS. I was formerly President of the Arizona Economic Round Table, a group of Arizona-based economists that specialize in studying the Arizona economy, and I am still a member of that organization. I also serve on the Joint Legislative Budget Committee's Finance Advisory Committee. This advisory committee consists of a group of state economists who advise the Joint Legislative Budget Committee staff on the adequacy of the economic projections underlying their state revenue projections.

Q. **WHAT IS THE PURPOSE OF YOUR REPLY TESTIMONY?**

A. The purpose of my testimony is to address the assertions made in Direct Testimony in Opposition of the Settlement Agreement by Ms. Barbara Wyllie-Pecora and Mr. Carl Faulkner that APS's current line extension policy (also known as Schedule 3) is somehow limiting growth in the state of Arizona.

Additionally, I will comment on the report by Elliot D. Pollack & Company entitled "Arizona Utilities – Modifications to Infrastructure Extension Policies Impact Analysis" ("Pollack Report") that was included in Ms. Wyllie-Pecora's opposition testimony. In order to gain a greater understanding of this report, APS deposed authors Mr. Richard C. Merritt and Mr. Daniel Court on August 3, 2009. Pertinent responses from Mr. Merritt regarding the scope of his report and its conclusions have been included in my testimony, and the entire deposition is attached as Attachment PME-1-S.

II. SUMMARY

Q. **PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I have seen no reports, analyses, or other information demonstrating that the Company's current line extension policy is in any material way affecting growth in Arizona. Neither the Pollack Report nor the other testimony filed by the opposing parties has provided any additional evidence that indicates, let alone proves, that Schedule 3 is having any quantifiable or material negative impact on state incomes, tax revenues or housing demand, or that the policy is somehow undermining the ability of the state to recover from the economic recession being felt around the country. Mr. Merritt, the author of the Pollack Report, acknowledges that he " . . . did not conduct any analysis of land values or the potential impact of the . . . changed Service Schedule 3 on the value of

land."[1] The Pollack Report also fails to consider the positive economic benefits likely created by keeping base rates lower than they otherwise would need to be for other customers. I conclude that housing demand has been primarily affected by the overall poor economy and in particular by the real estate bubble in Arizona.

III. LINE EXTENSION POLICY IMPACT ON GROWTH

Q. **DO YOU BELIEVE THAT APS'S LINE EXTENSION POLICY HAS NEGATIVELY AFFECTED GROWTH IN THE COMPANY'S SERVICE TERRITORY?**

A. No. There is absolutely no evidence to suggest that the change in the line extension policy has materially affected growth in the APS service territory. A simple review of the change in growth rates in the APS service territory over the last several years compared to the change in growth rates in the Salt River Project ("SRP") service territory confirms that the slowdown in growth is widespread and economy-wide, and not related only to one utility's service territory (or line extension policy). The following table displays the growth in annual residential customers for APS and SRP since 2004.

Growth in Average Annual Residential Customers

	APS		SRP	
	Number	%	Number	%
2004	30,703	3.7%	26,721	3.7%
2005	37,403	4.4%	32,436	4.3%
2006	39,992	4.5%	29,078	3.7%
2007	29,549	3.2%	20,088	2.5%
2008	11,931	1.2%	4,701	0.6%

[1] Deposition of Richard Charles Merritt and Deposition of Daniel Court, dated August 3, 2009, page 37 lines 2-5. *See* Attachment PME-1-S.

For reference, SRP's present line extension policy is similar to APS's previous line extension policy. Most importantly, it is readily apparent from the data that SRP has experienced a decline in growth that is similar to, if not a little more pronounced than, the decline seen in the APS service territory. One would not expect this to be the case if the line extension policy were responsible – or even partly responsible – for the decline in growth and the decline in housing demand. In fact, one would quite naturally expect to see the opposite.

Q. **BUT YOU DO AGREE THAT GROWTH HAS SLOWED CONSIDERABLY THROUGHOUT THE STATE IN THE PAST FEW YEARS?**

A. Yes, there is no doubt that both population and housing growth have slowed dramatically in the past three years. In fact, APS is experiencing the slowest growth in percentage terms now that we have seen in the last 50 years. The principal driver of this slowdown was the overbuilding that occurred in single family housing from 2004 to 2006. When it became apparent that our economy was building too many homes, the bubble popped, home prices and land values began to fall, and construction began to slow. As construction workers and others tied to the construction industry lost their jobs, many of them sought work outside the state. With more people leaving the state and fewer people moving into the state due to the poor job climate, net migration slowed down and the demand for housing declined even further. The net result is that we have an excess physical supply of housing in the APS metropolitan Phoenix service territory of over 30,000 homes and apartments. From the available housing permit data and customer data, it appears that SRP has had a similar experience in terms of housing construction and trends in occupied housing. Since APS accounts for just under half of the metro Phoenix residential electric customers,

a good approximation of the amount of vacant housing in metro Phoenix is on the order of 65,000 to 70,000 units.

Q. **ARE THESE UNITS VACANT BECAUSE OF THE CHANGE IN THE LINE EXTENSION POLICY?**

A. No. Virtually all of these constructed homes have electrical service to them. In fact many of the vacancies have occurred in the interior of the APS system in established developments and in apartments. The Company's line extension policy is not inhibiting residents from moving into them. To the contrary, it likely encourages residents to fill these vacancies thus helping alleviate the most significant problem facing the housing market.

Q. **DOES THE POLLACK REPORT INDICATE THAT THE CHANGE IN THE LINE EXTENSION POLICY IS RESPONSIBLE FOR THE DOWNTURN IN GROWTH?**

A. No. Essentially, the Pollack Report presents a hypothetical scenario that answers the question, "What would the economic impact to Arizona be if 100 average-size single family homes were not built in a year?" The Pollack Report does <u>not</u> claim, let alone prove, that the change in the line extension policy results in fewer homes being built.

Q. **IS THIS SIMPLY YOUR INTERPRETATION OF WHAT THE POLLACK REPORT SAYS?**

A. No. In addition to drawing my own conclusion from reviewing the report, Mr. Merritt also acknowledges that his report does not attempt to draw such a conclusion. In his deposition with the Company, he was asked a series of questions on this point:

> Q. Your study is thus not intended to present evidence that the change in line extension policies actually caused the economic impact you described in section 5 of your report?

A. Correct. Our -- for us to determine precisely what the impact of Service Schedule 3 is we would have to get into the mind set of people who own land in the rural areas that are impacted, people who would be potentially buying land, building homes in those areas. And we did not. Once again, it was a limited scope so we did not get into any of the detail on how the service schedule may impact the thought process of those people.

Q. Do I take it then that your study is not intended to present evidence that the change in line extension policies actually caused the impacts described in section 5?

A. Our analysis says that there is not enough information available to determine what the impact would be of Service Schedule 3. But for every 100 homes that may not be built in this, in the APS service area or other service areas, there is a particular impact on jobs and revenue that would be developed and generated to cities, state, counties.

Q. Do you have any evidence that 100 homes will not be built as a result of the changes to service schedule 3?

A. No, we do not.

Q. Do you have any evidence that 10 homes will not be built as a result of the change to service schedule 3?

A. No, we do not.[2]

Q. **DOES A DECLINE IN HOUSING VALUE COINCIDE WITH A DEPRESSED HOUSING MARKET?**

A. Yes, a decline in both housing and land values goes hand in hand with a significantly overbuilt market. In fact, the Pollack Report acknowledges that "The main cause of the decline [in housing values] stems from the collapse in the housing market and the flood of distressed properties placing downward pressure on sales prices. The lack of demand for developable private land has

[2] *Id.*, page 37, line 9 to page 38, line 14.

driven land prices down steeply."[3] These are the true reasons for the decline in growth and land values we are experiencing today, not a public policy decision on the cost of line extensions.

Q. **THE POLLACK REPORT INCLUDES A SPECIFIC LIST OF HOUSING TRANSACTIONS THAT PURPORTS TO SHOW THAT THE DISTANCE FROM ELECTRICAL SERVICE HAS A NEGATIVE EFFECT ON SALES PRICE. IS THIS LIST RELEVANT?**

A. Without significantly more detailed analyses, I don't see how it could be. The Pollack Report provides no evidence at all that the sale prices contained in the table on page 19 bear any relationship to the cost of a line extension to these properties. The report contains no detailed analysis that would confirm or disprove that an extension policy affected these prices. By my rough approximation, the geographic area covered by these transactions appears to be close to 12 miles from north to south and 11 miles from east to west, or over 130 square miles. In my opinion, that appears to be a fairly broadly defined region in which one would not expect that land values would be directly comparable across the entire region. Furthermore, there is no indication as to the representative nature of the transactions. Are they representative of all transactions in the region? Could some of the sales been made under financial distress and others not? At the very least, one needs to know when these transactions occurred to have an idea of why the prices may differ – and there is no discussion of any other differences in amenities or improvements that may or may not have been available at the time of the sale. Simply stating that prices decline in conjunction with distance to electrical service does not make it so.

[3] *See* Pollack Report, Executive Summary page ii.

Q. **DO ANY OF THE PARTIES OFFERING TESTIMONY IN SUPPORT OF MS. WYLLIE-PECORA, INCLUDING MR. FAULKNER, PROVIDE ANY EVIDENCE TO SUPPORT THEIR ASSERTIONS THAT THE LINE EXTENSION POLICY IS AFFECTING GROWTH IN THE STATE?**

A. No. They have provided no studies or analyses as evidence that the change in the line extension policy has affected growth in Arizona in a material way.

Q. **DO YOU BELIEVE THAT, AS SUGGESTED BY BOTH THE POLLACK REPORT AND MR. FAULKNER, THE CHANGE IN THE LINE EXTENSION POLICY MAY HAVE AN AFFECT ON CERTAIN LANDOWNERS?**

A. As I indicated previously, I believe that there are many factors that go into the determination of land values, so I believe that it is very difficult to generalize to an entire group of customers without solid evidence, which Mr. Faulkner and others have failed to provide. Having said that, I do believe that it is possible that certain individuals may have been affected by the change in the line extension policy, but even so, anecdotal evidence can not be extrapolated to the sweeping generalizations contained in their testimony.

Q. **DOES THE INTERVENOR TESTIMONY AND POLLACK REPORT IDENTIFY AND ADDDRESS ALL THE RELEVANT ECONOMIC ISSUES YOU BELIEVE THE COMMISSION SHOULD CONSIDER AS IT ADDRESSES THIS ISSUE?**

A. No. In my opinion, the Commission should rely on the best economic criteria it can to set a policy that applies equally to everyone. Without trying to be exhaustive, I would suggest that some of the factors to be considered would include:

- The impact on base revenue requirements caused by exempting certain customers from the full cost of extending service.
- The impact on allocative efficiency, meaning resources (land, labor, materials) are expended when consumers and businesses are willing to

pay those resource costs, and not expended when willingness to pay is too low.

- Related to the first point, whether costs are allocated to those who cause or create them.
- The impact on the economy generally if subsidies are to be used, meaning capturing the impacts on the level of economic activity of higher electric rates overall resulting from cost-shifting subsidies.
- The impact on specific sets of consumers if subsidies are to be used.
- The impact on the type of development that may occur in the state, including the amount of infill development that may occur.
- Slightly different from the previous point, the short-run impacts on the housing market and its potential path to recovery.

There are almost certainly other factors that could and should be considered in the review of the line extension policy, and those factors should be brought out. I am quite confident that the intervenor testimony offered in this case has not done this.

Q. **DOES THIS CONCLUDE YOUR REPLY SETTLEMENT TESTIMONY?**

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

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-08-0172
	)	PERMANENT

DEPOSITION OF RICHARD CHARLES MERRITT

and

DEPOSITION OF DANIEL COURT

Phoenix, Arizona
August 3, 2009

ARIZONA REPORTING SERVICE, INC.
Court Reporting
Suite 502
2200 North Central Avenue
Phoenix, Arizona 85004-1481

Prepared for:

By: COLETTE E. ROSS
Certified Reporter
Certificate No. 50658

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1 DEPOSITION OF RICHARD CHARLES MERRITT and DANIEL COURT
2 was taken on August 3, 2009, commencing at 9:33 a.m., at
3 the offices of ARIZONA PUBLIC SERVICE COMPANY, 400 North
4 Fifth Street, Phoenix, Arizona, before COLETTE E. ROSS,
5 Certified Reporter No. 50658 for the State of Arizona.
6
7 APPEARANCES:
8
For Arizona Public Service Company:
9
PINNACLE WEST CAPITAL CORPORATION
10 Law Department
By Ms. Meghan H. Grabel and Mr. Thomas L. Mumaw
11 400 North Fifth Street
Phoenix, Arizona 85004
12
13 For the Arizona Corporation Commission Staff:
14 ACC, Legal Division
By Mr. Charles Hains
15 1200 West Washington Street
Phoenix, Arizona 85007
16
17 For the Intervenor Wyllie-Pecora:
18 Ms. Barbara Wyllie-Pecora and Mr. Todd Wyllie
27458 North 129th Drive
19 Peoria, Arizona 85383
20
21
22 ALSO PRESENT:
23 Messrs. David Rumolo, Pete Ewen, APS
Mr. Ralph Smith, appearing via teleconference
24 Ms. Jody Jerich, RUCO, appearing via teleconference
25

(Whereupon Richard Charles Merritt was duly sworn by the Certified Reporter.)

THE WITNESS: Can I just ask you the format?

MS. GRABEL: Oh, sure. Shall we go off the record, please.

(An off-the-record discussion ensued.)

RICHARD CHARLES MERRITT,

a witness herein, having been previously duly sworn by the Certified Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MS. GRABEL:

Q. My name is Meghan Grabel. I am an in-house attorney here with Pinnacle West. This is my colleague, Tom Mumaw, also an in-house attorney with Pinnacle West.

I will ask you preliminary questions. Tom will ask you additional questions. And then it is going to come back to me for other questions. Because of the short time, we tag teamed here.

Mr. Smith, you can't hear?

MR. SMITH: I can't hear very well.

MS. GRABEL: I will speak louder. And at a break we will see if we can get you a different number

that you can call that will hopefully solve this. Does that work?

MR. SMITH: Yes, that works.

MR. RUMOLO: Ralph.

MR. SMITH: Yes.

MR. RUMOLO: What number are you at? Let me see if I can call you on this speaker line.

MS. GRABEL: Let's go off the record.

(An off-the-record discussion ensued.)

(The record was read by the reporter as requested as follows:

Ms. Grabel: I will ask you preliminary questions. Tom will ask you additional questions. And then it is going to come back to me for other questions. Because of the short time, we tag teamed here.)

BY MS. GRABEL:

Q. And then Mr. Hains from the Arizona Corporation Commission will also have the ability to ask questions when we are done.

A. Okay.

Q. So you understand that you are under oath today and testifying the same as you would if you were at any trial or hearing?

A. Yes.

Q. It is important for our purposes that we maintain a clean record here. So if we could, please, try not to talk over one another. I will try to extend that courtesy to you as well.

A. Sure.

Q. In the same vein, please answer yes or no, not uh-huh or huh-uh.

Are you taking any medication that would affect your ability to understand the questions that I ask you?

A. No.

Q. We hope not to go too long today. As I said earlier, we hope to be done about 12:30. But if you need a break, feel free to take one for any reason, just let me know.

A. Okay.

Q. Would you please state your full name for the record.

A. Richard Charles Merritt.

Q. And what is your address?

A. My home address?

Q. Yes.

A. 17478 north 100th Way in Scottsdale, Arizona.

Q. Have you ever had your deposition taken before?

A. Yes.

Q. When?

A. The last time was probably six to seven years, something like that.

Q. What context was that deposition?

A. It was in a mediation.

Q. Personal matter or business matter?

A. No, business matter.

Q. Were you acting as an expert consultant in that matter?

A. I was acting as an employee of the principal in a real estate matter, is what it was.

Q. Have you had your deposition taken prior to that time?

A. Yes.

Q. How many times have you been deposed?

A. Probably four to five times.

Q. All personal -- all business, rather, related?

A. All business, yes.

Q. Have you ever testified at the Arizona Corporation Commission?

A. No.

Q. Have you ever testified in court or in any other legal proceeding?

A. Yes.

Q. When?

A. In court, it was probably, it has been as long

as 25 years ago, probably.

Q. What was the context?

A. It was a zoning matter. I was employed by the Town of Gilbert at the time.

Q. Were you called to speak in an expert capacity there?

A. Yes.

Q. What was the subject?

A. It was, it was a question of legitimacy of zoning on a particular piece of property.

Q. How long did you prepare for your deposition today?

A. I spent probably a total of eight to ten hours last Friday and the weekend.

Q. What did you do?

A. Mainly reviewed the report and background material that was provided to us.

Q. What specific background material did you review?

A. Mainly just boning up on the various schedules, information that was provided in the document, the study itself, those types of things.

Q. Were any of the documents that you reviewed to prepare for your deposition today not attached to the report that has been filed in the Arizona Corporation

Commission docket?

A. Yes. There were some, and schedules. The schedule, Service Schedule 3 was not attached to the documents.

Q. Did you review anything in addition to Service Schedule 3 that was not also attached to your report?

A. There were various documents that we collected along the way in the study that are in, mostly in your electronic files that I went through, yes.

Q. Would it be possible for us to have a copy of those documents?

A. Sure.

Q. Did you bring copies with you today?

A. Not all copies, no.

Q. You can follow up?

A. Yes.

Q. Did you meet with anyone to prepare for your deposition?

A. No, other than spoke to Danny Court.

Q. Did Mr. Court work with you on this matter?

A. Yes.

Q. How long did you speak with Mr. Court?

A. Probably no more than, in total, no more than half an hour or something like that.

Q. What is your educational background?

A. I have a bachelor's of community planning from the University of Cincinnati and I have an MBA from Arizona State.

Q. Are you an economist?

A. Technically not, no.

Q. Did you take any economics courses as part of your bachelor's?

A. Very little as part of the bachelor, more as part of the master's, yes.

Q. How long have you worked for Pollack & Associates, and forgive me, Elliott D. Pollack & Company?

A. Well, formally the company started, Elliott and I started the company in about 1990. Prior to, I was working for him in charge of managing various real estate investments that he had, starting in about 1986, 1987.

Q. What is your current position with Elliott D. Pollack & Company?

A. I am the president.

Q. What are your duties and responsibilities?

A. Primarily there are two parts of our business. One is the consulting business, Elliott Pollack & Company. And I spend probably, you know, over the course of a year, about half my time on that aspect of

1 the business, just overseeing various studies and
2 analyses that we do. And the other half of my time is
3 still spent in the real estate investment area, managing
4 the properties that we have acquired over, well, some go
5 back 20 years or so now.
6 Q. Who are your clients in the real estate
7 investment portion of Elliott D. Pollack &
8 Associates -- & Company?
9 A. We have a wide variety of private and public
10 clients. We work for many of the major cities around
11 the valley. We have worked for the state, for the
12 county. We are the basically the economic forecasting
13 arm for Maricopa County. We do a lot of work with the
14 City of Phoenix.
15 And then we have a lot of private clients that
16 range from big companies like Del Webb to small
17 independent landowners, investors, developers who may be
18 asking questions about the real estate market.
19 Q. And do you recommend investments that should be
20 made?
21 I am trying to understand. You said you managed
22 the properties in your portfolio. What does that mean
23 specifically?
24 A. Well, that is totally separate from Elliott
25 Pollack & Company.

Q. Okay.

A. And the properties that we -- well, they are, they are limited partnerships or LLCs that are formed by Elliott and some of his other partners. And basically it is managing the properties anywhere from just letting it sit as an agricultural property to developing properties, rezoning, master planning and whatever it may be.

Q. Does part of your compensation from your Elliott D. Pollack & Company branch, so to speak, come from the investment position that you have?

A. Yes, yes.

Q. Who did you work for prior to Elliott D. Pollack & Company?

A. I worked for an company called Northern Equities.

Q. What do they do?

A. They were in the development business here in the Phoenix area.

Q. What were your duties and responsibilities?

A. It was, once again, managing properties, taking them from perhaps a raw piece of land to a developed piece of property so it could be sold.

Q. For how long did you work -- what was the name of the business again?

A. Northern Equities.
Q. For Northern Equities?
A. How long?
Q. For how long?
A. I worked for them for about three years.
Q. Why did your employment end?
A. Well, we were in a pretty huge real estate recession and they were in a mode to scale down. And at that time I started working for Elliott on similar matters.
Q. For whom did you work prior to Northern Equities?
A. For the Town of Gilbert, I was the planning director for the Town of Gilbert.
Q. What does that mean?
A. Well, the planning director is in charge of, responsible for the general plan of the city, of the community, zoning, processing of development plans, things of that nature.
Q. For whom did you work prior to the Town of Gilbert?
A. I worked for the City of Chandler.
Q. In what capacity?
A. As -- I don't remember my exact title but I was a staff planner.

Q. What did you do as a staff planner in the City of Chandler?

A. Many of the similar things of zoning, development, review, general plan analysis, things of that nature.

Q. For whom did you work prior to the City of Chandler?

A. I worked for Hamilton County, Ohio after I got out of school in Cincinnati.

Q. What year was that?

A. I graduated in '74 and moved here in 1979, went to work for the City of Chandler.

Q. You received your MBA in '74?

A. No, my --

Q. Okay.

A. -- my bachelor's in '74.

Q. What year did you receive your MBA?

A. 1990.

Q. Are you the author of the report entitled Arizona Utilities - Modifications to Infrastructure Extension Policies Impact Analysis?

A. Yes.

Q. Who retained you to complete your analysis?

A. The entity we are familiar with is Arizonans for Fair Power Policy.

Q. When were you retained?
A. That's a good question.
MR. COURT: January.
THE WITNESS: Yes, it was probably around the beginning of the year.
BY MS. GRABEL:
Q. 2009?
A. Yes.
Q. Do you work primarily with any one individual or two individuals with the Arizonans for Fair Power Policy?
A. We primarily work with a gentleman, Mike Wyllie.
Q. How often did you meet with Mr. Wyllie?
A. Personally I met with him one time, I believe.
Q. Did you have any telephone conversations with Mr. Wyllie?
A. Yes, we had telephone conversations. My assistant had numerous conversations with him directly, too.
Q. Over the course of your analysis about how often do you believe you had any interactions with Mr. Wyllie or Mr. Court? Let me ask that a better way.
Over the course of your analysis, how often do you believe that you personally had any interactions, e-mail, telephone, in-person meetings, with Mr. Wyllie?

A. I would say probably once a month.

Q. And over the course of your analysis how often do you believe that Mr. Court may have had communications of any type --

A. It was --

Q. -- with Mr. Wyllie?

A. At some point it was very little. At other times it was weekly at the very least.

Q. What did Mr. Wyllie ask you to do?

A. He asked us to provide him an impact analysis of the revision to the schedule, Service Schedule 3.

Q. Was his request specific to APS or did it include the other utilities that you have included in the scope of your report?

A. It was initially directed at APS, yes.

Q. What caused you to broaden the scope of your assignment?

A. Well, as we got into a more -- and spoke with Mr. Wyllie, we understood that there were additional changes made to other service schedules by the other utilities. And at that point we broadened the study a little bit.

Q. Did you share drafts of your work with Mr. Wyllie?

A. Yes.

Q. Did you revise those drafts based on Mr. Wyllie's input?

A. There were some minor revisions made along the way.

Q. In what areas did you revise the report based on Mr. Wyllie's feedback?

A. I, to tell you the truth, I cannot remember specifically what the major changes were, but they are very minor.

Q. Would you be willing to take a look?

A. Yes.

Q. To what extent was Mr. Wyllie or anyone else with the Arizonans for Fair Power involved in formulating the analysis that you submitted in this report?

A. He was a primary one, but we did have one meeting where he brought in some additional associates, and we probably spent an hour listening to their concerns about the service schedule.

MS. GRABEL: Can we take a quick break.

(An off-the-record discussion ensued.)

(Ms. Jody Jerich joins the proceedings via teleconference.)

BY MS. GRABEL:

Q. Thank you for your prior answer, Mr. Merritt.

To what extent was your client involved in formulating the analysis that was a part -- that you reached in this report?

A. Well, mainly in providing information on what they thought the impact was of the revisions to the service schedule. And that was the provision of a lot of different testimony from people, mainly real estate investors or sales agents regarding what it meant to them, to clients and property owners, what the impact was of the service schedule.

Q. Did you look at any data that was not provided to you by your client in preparing your analysis?

A. Yes, I am sure we did.

Q. I sense a little hesitation. Why do you hesitate?

A. Well, there is not a lot outside of the actual economic impact analysis. I think that's the main thing that we, we evaluated and worked on.

Q. I don't think I fully understand your distinction. What in your impact analysis, what data that you relied upon in devising your impact analysis was not provided to you by your client?

A. What was not provided? It was primarily the -- there was statistical reports. There were annual reports that we pulled out off the internet regarding

1 APS. And then primarily it was the remaining economic
2 impact analysis that is shown throughout the study.
3 Q. And are those documents documents that you will
4 be providing to us pursuant to my earlier request?
5 A. Sure.
6 Q. Thank you.
7 What is your compensation arrangement with the
8 Arizonans for Fair Power Policy?
9 A. We were paid a flat fee of $8,000 to do the
10 study. If there is any testimony at the ACC, they would
11 be responsible for payment of that as well.
12 Q. Is this deposition part of the $8,000 flat fee?
13 A. No. It was our understanding that APS was
14 paying for my time.
15 Q. It was my understanding, too. I was just sort
16 of hoping. Just kidding.
17 How much have you been paid to date of that
18 $8,000?
19 A. I know we received a $4,000 retainer. And I
20 believe the other, I know we billed for the remaining
21 4,000. I just don't know if we have been paid.
22 Q. And how much do you estimate you will be paid by
23 your client for the duration of your assignment?
24 A. I don't know that we have come to a complete
25 estimate at this point.

Q. Do you expect that you will be testifying in this case?

A. I have been told that we are expected to testify, yes.

Q. Do you have any estimate about how long it will take you to prepare for that testimony?

A. It depends on whether there is a written testimony that goes along with it as well in addition to a verbal testimony. You know, I think we thought maybe it would be another 10 to 15 hours of work, something like that.

Q. And is the compensation past the $8,000 flat fee an hourly basis?

A. Yes.

Q. How much per hour?

A. For -- it would probably be between, my rate and Danny's rate would probably be an average of $175 an hour, something like that. And thee would be a higher fee for the direct testimony at a hearing.

Q. I wish I could do that.

Do you have any prior experience conducting any analyses similar to the one completed on behalf of the Arizonans for Fair Power Policy?

A. Yes.

Q. Will you elaborate.

A. We, as probably the largest part of our business is economic and fiscal impact analyses, and we virtually do them in our sleep at this point. We have various models that we use to conduct these analyses. And it is a matter of figuring out what the assumptions are of the particular issue and then developing a model around that.

Q. Have you ever attempted to analyze the impact of a government tax or fee on the Arizona economy?

A. We have looked at impact fees, city impact fees, yes.

Q. Are the reports public that were devised?

A. They were all done for private clients. We have done a fiscal impact analysis for, not a fiscal impact analysis, a development fee study for the Town of Gila Bend. We have done one for La Paz County. Those are the two that I remember offhand. But other than that, we have worked in the private side for developers, home builders who were protesting the imposition of impact fees by cities.

Q. I guess I meant my question a little bit differently. Are the results of those studies publicly available? Are you able to give those --

A. The private ones, I would have to check to see if they were submitted to the cities. Then I would

1 assume they are public information, yes.
2 Q. If they are, would you be willing to provide us
3 with a copy of those as well?
4 A. Sure.
5 Q. Thank you.
6 Do you have --
7 A. Will you give me a list at the end of this
8 information?
9 Q. Sure, absolutely.
10 Do you have any past experience analyzing
11 utility economics?
12 A. No.
13 Q. Does anyone at Elliott D. Pollack & Company have
14 past experience analyzing utility economics?
15 A. Yes. We have done work for utilities. I am not
16 sure that we focused on the type of analysis you are
17 talking about. But we have done work for Southern
18 California Edison on various issues, but they have
19 mostly been in the field of economic impact analysis.
20 Q. Economic -- when you did work for Southern
21 California Edison, for example, what was the impact
22 analysis they asked you to do?
23 A. They have, we have done some extensive models
24 for them that showed what the impact would be of a
25 particular company coming into their service area, for

1 instance.
2 Q. Do you have any past experience analyzing
3 utility policies regarding line extensions?
4 A. No.
5
6 EXAMINATION
7 BY MR. MUMAW:
8 Q. You indicated that you had not previously
9 conducted studies regarding utility line extension
10 policies, is that correct?
11 A. Yes.
12 Q. Has Mr. Court conducted such a study?
13 A. No, I don't believe so.
14 Q. Is Mr. Court the only person at Elliott Pollack
15 who assisted you in this study?
16 A. In this particular study, Jim Rounds is our
17 senior economist, he reviewed the study prior to its
18 final completion and provided us some comments on it.
19 Q. Do you know whether Mr. Rounds had previously
20 conducted any studies regarding the impact of utility
21 line extension policies?
22 A. To my knowledge he has not conducted any such
23 study.
24 Q. Mr. Merritt, are you aware of any similar
25 studies being conducted for other utilities elsewhere in

1 the country?
2 A. No, I am not aware.
3 Q. So to your knowledge yours is the first and only
4 study of this kind?
5 A. To my knowledge, it is the only one. We have --
6 we did not as part of our study do any further research.
7 Q. Mr. Merritt, with regard to APS' Schedule No. 3,
8 the so-called 1,000 free footage provision, are you
9 familiar with that provision?
10 A. Yes.
11 Q. And in your understanding, in that version of
12 Schedule 3, to what sort of applicants did that free
13 footage apply?
14 A. Well, it primarily applied to single-family
15 residences that were not being built in a traditional
16 subdivision, if you want to call it that.
17 Q. Isn't it true that it only applied to those
18 sorts of applicants?
19 A. To my knowledge, I can't say for sure that's the
20 only, that's the only one. We are, you know, we are
21 very, if I can just clarify a little bit, we were very
22 specific on the type of analysis we were conducting.
23 And it was primarily targeted at the economic impact.
24 We did not do extensive analysis of what Service
25 Schedule 3 was all about other than what we did to

1 understand the overall picture of what was going on.
2 Q. Okay. So is it your understanding that
3 developers, for example, did not receive free footage
4 allowance?
5 A. Developers?
6 Q. Yes.
7 A. Subdividers?
8 Q. Yes.
9 A. They did not collect such.
10 Q. And commercial applicants for service did not
11 receive any free footage?
12 A. That's correct.
13 Q. And Schedule 3 also covers upgrades of service
14 from existing customers?
15 A. I am not aware of that provision.
16 Q. If -- could I ask you to assume that it does
17 cover upgrades of service?
18 A. Okay.
19 Q. You would agree in that circumstance free
20 footage would not be a relevant concept?
21 A. It would not be a relevant concept?
22 Q. Yes, that we are not talking about those --
23 people who upgraded service did not get any sort of free
24 allowance.
25 A. Okay, yes.

Q. Okay. Was it your understanding that for those customers to whom the free footage applied, that there was a dollar cap?

A. Yes.

Q. And what was that dollar cap?

A. $25,000.

Q. And what is your understanding, if the project was in excess of $25,000, how do you believe Schedule 3 applied in those circumstances?

A. That the applicant, homeowner, whoever it was, would make up the difference between the actual cost and the $25,000 allowance.

Q. Isn't it in fact true, Mr. Merritt, if the project exceeded $25,000 it was moved out the footage category, if you will, into the economic analysis?

A. I am not --

Q. -- category?

A. I am not aware of that provision.

Q. Okay. Do you know whether it was true that in most instances which a project exceeded $25,000 the applicant was required to advance the full cost of that project?

A. No. I was not aware of that provision.

Q. If you had been aware that that's how previous versions of Schedule 3 applied, would that have affected

your analysis?

A. I don't believe so, no.

Q. Do you know when it was first proposed by APS to get rid of the free footage allowance?

A. I don't know the exact date. I believe that it was in 2007, was my understanding.

Q. Would it surprise you if it was as early as 2003?

A. No.

Q. Was it your understanding that APS originally proposed to substitute for the free footage a specific dollar allowance, dollar equipment allowance, I think it was called?

A. I did read something, yes, I did read a provision like that.

Q. Is it your understanding that APS proposed to substitute for the thousand free foot allowance a $5,000 equipment allowance?

A. I am not aware of that, no.

Q. Did you do any analysis as to whether or not the change from the free footage allowance to the flat dollar equipment allowance would have had the same impacts that you discussed in your study?

A. We did not go into detail like that, no.

Q. Would it be fair to say, Mr. Merritt, that if

1 this had been proposed by the company as far back as
2 2003, it shouldn't have come as any particular surprise
3 that the policy was changed?
4 A. I am not, I am not able to comment on the
5 aspects of it.
6 Q. In your study you discuss the line extension
7 policy of Tucson Electric Power and UniSource Electric,
8 is that correct?
9 A. Yes.
10 Q. And I believe you made mention in the Tucson
11 Electric Power line extension policy that this
12 previously allowed 500 foot?
13 A. Yes, I believe that's correct.
14 Q. And UniSource, I think, was kind of an
15 inside/outside of 400 foot, I think, of primary and 150
16 feet of secondary, is that correct?
17 A. That sounds familiar, yes.
18 Q. And again, as I asked you with regard to APS, do
19 you know to which applicants for service in the case of
20 Tucson the 500 foot applied?
21 A. No, I do not know the specifics on that.
22 Q. So you don't know whether it applied to
23 developer or commercial applicants?
24 A. No.
25 Q. Same answer with regard to the UniSource policy?

1 A. Yes, right.
2 Q. You would agree that the Tucson and UniSource
3 policies were less generous than the old APS policy?
4 A. Yes.
5 Q. Did you do any sort of analysis to determine
6 whether these policies of Tucson Electric Power and
7 UniSource had any sort of adverse impact on real estate
8 values within their respective service territories?
9 A. No, we did not.
10 Q. Did you make any analysis as to whether, with
11 regard to the APS service territory, that something less
12 than a thousand feet would avoid the adverse impacts on
13 real estate that you discuss in this study?
14 A. We did not look at those aspects, no.
15 Q. So would it be fair to say your study was kind
16 of an all or nothing sort of analysis?
17 A. It was a very specific study of what happens if
18 100 homes are not built as a result of these policies
19 and what is the impact of the loss of those 100 homes.
20 That's basically very straightforward as to what it is.
21 Q. In fact, if no homes were lost because of this
22 policy, it stands to reason there would be no impact,
23 correct?
24 A. If that is the case, yes.
25 Q. You indicated earlier in response to a question

1 from Ms. Grabel that Pollack & Company had utility
2 companies as clients, is that correct?
3 A. Yes.
4 Q. Do you recall your firm being retained by
5 Arizona Public Service Company several years back?
6 A. I, personally, I don't remember the case. I am
7 not involved in every case that goes through the
8 company.
9 Q. So you don't know whether or not Mr. Pollack
10 himself performed a study analyzing the impact on
11 Arizona should Arizona Public Service Company not be
12 able to maintain an investment grade debt rating?
13 A. I am not aware of that study, no. I don't doubt
14 that it was, we did produce it, yes.
15 Q. Mr. Merritt, I know you testified as to your
16 extensive experience in the real estate industry. Have
17 you actually ever appraised property?
18 A. In the past, yes. We were an appraisal firm.
19 We are not anymore.
20 Q. Appraising residential real estate?
21 A. It was primarily more land and commercial
22 property.
23 Q. Okay. Now, you are aware, are you not,
24 Mr. Merritt, that Arizona Public Service Company and a
25 number of other parties to its pending rate case have

1 entered into a settlement agreement?
2 A. Yes.
3 Q. And are you aware that that settlement agreement
4 proposes to keep Schedule 3 as it presently is, in other
5 words, with no free footage allowance and no equipment
6 allowance?
7 A. As far as I know, that's my understanding, yes.
8 Q. And is it your understanding that with some,
9 other than some changes in structure of the schedule,
10 that the primary change in the settlement is the
11 accounting of proceeds being changed from being a
12 customer contribution being treated as a revenue?
13 A. I am not aware of that provision, no.
14 Q. You would agree that from the, from the
15 viewpoint of the applicant for service, how the company
16 accounts for those proceeds, whether it is contribution
17 or revenue, should be a matter of indifference?
18 A. Yes.
19 Q. Would you agree that it probably is not a matter
20 of indifference to Arizona Public Service Company?
21 A. Yes, I am sure it is.
22 Q. And are you aware that in the settlement that
23 the assumption has been that Schedule 3 will provide the
24 company with a certain degree of revenues?
25 A. Yes.

Q. And do you know what the level of those revenues are?

A. No, I don't know.

Q. If I asked you to accept that the company has estimated that the revenues would be approximately $100 million over the next three years, would you agree that that's substantial?

A. If that's an accurate number, yes, that's substantial.

Q. And if in fact the Commission were to accept the arguments of the Wyllies and revert the schedule back, Schedule 3 back to some version prior to the existing one, do you believe Arizona Public Service Company should be compensated for that loss of revenue?

A. I don't -- I really think that's out of the purview of what we looked at and studied. I don't really have a comment on that, no.

Q. You would agree that if the company were not being -- strike that.

You would agree that if the company is not compensated for that loss of revenue that that would have a substantial negative impact on APS?

A. I, I really cannot comment, because I don't, I don't know the structure, financial structure of APS or how it all fits together. I really would not -- we did

1 not do any study of the APS, APS as a company. And I
2 just would really have no opinion on it, no knowledge of
3 it.
4 Q. So let me ask this, Mr. Merritt: You were not
5 asked to examine the impact of a change in Schedule 3 on
6 APS?
7 A. No.
8 Q. And is it possible, Mr. Merritt, that the impact
9 on APS could be sufficiently negative that it would cost
10 a lot more than a hundred lost new homes?
11 A. I, once again, I have -- I don't know that I
12 have any kind of conclusion on that at all.
13 Q. One last area, Mr. Merritt, and then I will butt
14 out here. You compared Schedule 3 to Tucson Electric
15 and UniSource. Did you compare APS' line extension
16 policy to any other Arizona utilities?
17 A. No.
18 Q. Did you compare APS' line extension policy to
19 any utilities outside of Arizona?
20 A. No.
21 Q. So you have no opinion as to whether or not APS'
22 current Schedule 3 is more in tune with national
23 practice than its previous one?
24 A. No.
25 Q. Do you know whether there are any line extension

policies as generous as APS' was when it allowed a thousand free foot?

A. No, I do not.

MS. GRABEL: Back to me.

MR. MUMAW: Thank you, Mr. Merritt.

THE WITNESS: Thank you.

EXAMINATION CONTINUED

BY MS. GRABEL:

Q. Mr. Merritt, we would like to turn now to your report, which I would like to mark as APS Exhibit No. 1.

(Exhibit APS No. 1 was marked for identification.)

BY MS. GRABEL:

Q. Mr. Merritt, do you recognize this document?

A. Yes.

Q. We have established that you were the author of this report, correct?

A. Yes.

Q. Did you conduct the analysis described herein?

A. Mr. Court primarily conducted a lot of the analysis and I oversaw the study.

Q. What is Mr. Court's background?

A. Mr. Court has a bachelor's of economics from ASU and has worked for the company for two years, two years

now.

Q. Did Mr. Court come to the company straight out of school?

A. Yes, yes.

Q. What does he do primarily?

A. He is one of our economic analysts that provide a lot of the background information and content and analysis that goes into the studies.

Q. Are the conclusions reached within the report your conclusions?

A. Well, they are the company's conclusions, yes.

Q. And by the company, in this case it would be you and Mr. Court discussing together with, I believe you said earlier, Mr. Rounds?

A. Right, yes.

Q. What is Mr. Rounds' background?

A. He has a bachelor's and a master's of economics from ASU.

Q. How long has he been practicing with your company?

A. I believe it is about eight years now.

Q. What was he doing before that?

A. He worked for the joint legislative budget committee at the state.

Q. Would you agree that the study summarized

1 primarily the potential impact of line extension
2 policies on individual residential properties?
3 A. Yes.
4 Q. If you could, turn first to the executive
5 summary in Romanette one, Romanette i I guess you call
6 it. And underneath the purpose, in the second sentence
7 in the first paragraph you describe your analysis as
8 limited, a limited impact analysis. What do you mean by
9 that?
10 A. What I mean primarily is that we are taking a
11 very short general look at the issue. We did not have a
12 large enough budget to get into a lot of detail about
13 the issue and about the potential impact. And that's
14 why we considered it to be limited in scope.
15 Q. You note a couple of times in your report that
16 you did not conduct a, quote, detailed statistical
17 analysis of land prices in the rural parts of greater
18 Phoenix.
19 A. Right.
20 Q. What would a study like that have entailed?
21 A. It would have entailed collecting a large amount
22 of sales information on rural properties and trying to
23 evaluate what the various circumstances are that
24 determine the value of those properties.
25 Q. And how did what you did in this case compare to

1 that type of analysis?
2 A. Well, we did not conduct that analysis. We did
3 not conduct any analysis of land values or the potential
4 impact of the service schedule, the changed Service
5 Schedule 3 on the value of land.
6 Q. You did not analyze the potential impact of
7 Service Schedule 3 on the value of land?
8 A. Correct.
9 Q. Your study is thus not intended to present
10 evidence that the change in line extension policies
11 actually caused the economic impact you described in
12 section 5 of your report?
13 A. Correct. Our -- for us to determine precisely
14 what the impact of Service Schedule 3 is we would have
15 to get into the mind set of people who own land in the
16 rural areas that are impacted, people who would be
17 potentially buying land, building homes in those areas.
18 And we did not. Once again, it was a limited scope so
19 we did not get into any of the detail on how the service
20 schedule may impact the thought process of those people.
21 Q. Do I take it then that your study is not
22 intended to present evidence that the change in line
23 extension policies actually caused the impacts described
24 in section 5?
25 A. Our analysis says that there is not enough

1 information available to determine what the impact would
2 be of Service Schedule 3. But for every 100 homes that
3 may not be built in this, in the APS service area or
4 other service areas, there is a particular impact on
5 jobs and revenue that would be developed and generated
6 to cities, state, counties.
7 Q. Do you have any evidence that 100 homes will not
8 be built as a result of the changes to Service
9 Schedule 3?
10 A. No, we do not.
11 Q. Do you have any evidence that 10 homes will not
12 be built as a result of the change to Service
13 Schedule 3?
14 A. No, we do not.
15 Q. Do you have any evidence that one home will not
16 be built as a result of changes to Service Schedule 3?
17 A. We do not have any direct evidence other than
18 the testimony we have heard from various parties that
19 are involved in real estate in the rural areas.
20 Q. Why didn't, why didn't you conduct a detailed
21 statistical analysis of land prices from the rural parts
22 of greater Phoenix?
23 A. Just it would have been, well, it was beyond the
24 scope of what we could have done with the budget we had
25 basically. And in order to do that, it would have been

a very costly type of study for the client.

Q. You would agree that a number of factors influence sales price and land value, correct?

A. Yes.

Q. The general state of the economy, for example?

A. Yes.

Q. What is more likely to influence the price of land and land value, the general state of the economy or a utility line extension policy?

A. Well, I don't know that I can answer that. We are at a unique point in our history economically. And we just didn't, did not get into enough detail to come to any conclusion like that.

We do know that electric, electrical service is the one thing you do need to basically build a house. Without that, you are sunk. You can always dig a well. You can dig a septic tank. You can do lots of things to build a home, but if electric service isn't there, it is much, much more difficult.

Q. Is there anything within Service Schedule 3 that prohibits any landowner from --

A. No.

Q. -- receiving electrical service?

A. No.

Q. Wouldn't you agree that the main cause of the

1 recent decline in land value stems from the collapse in
2 the housing market and the flood of distressed
3 properties placing downward pressure on sales prices?
4 A. That certainly is a factor. But the change to
5 Service Schedule 3 likely had an impact as well on land
6 values. What that is we don't know, but certainly it is
7 an important factor.
8 Q. You have agreed that you have no evidence that
9 even one home will not be built as a result of the
10 change to Service Schedule 3. How can you conclude then
11 that the change in service schedules or line extension
12 policies in general had an economic impact?
13 A. Primarily coming from testimony of the people
14 that have submitted affidavits or documentation to the
15 Corporation Commission. We have done extensive
16 interviews. Mr. Court has done interviews of public
17 agencies, assessors who were involved in the business of
18 appraising property and developing property tax
19 statements, things of that nature. So there is a lot of
20 anecdotal evidence that we looked at that we considered
21 in our study.
22 Q. To what extent is anecdotal evidence proof of
23 causation between a change in line extension policies
24 and the economic impacts that you described in section 5
25 of your report?

1 A. Well, for the most part, it does help you get
2 into the head of that person who owns land or who is
3 buying land, who is talking about building a home and
4 what, what their opinions are of how the service
5 schedule did impact their thought process.
6 So it is a valid way of gauging what is going on
7 in the marketplace. But, once again, it is not a -- we
8 do not have statistical evidence of what those impacts
9 may actually be.
10 Q. Do any of the people whom you or Mr. Court
11 interviewed themselves have any study that correlates
12 the change in line extension policies to the economic
13 impacts described in section 5 of your report?
14 A. There is some information provided to us by
15 Mr. Wyllie that correlated, or, you know, once again, it
16 is not a statistical analysis, but it provided the value
17 of the price of land paid and the distance from
18 electrical service. And there is a table in the report
19 that speaks to that.
20 Q. We will turn to that table in a moment.
21 A. Okay.
22 Q. Distance from water also influences land price
23 and value, correct?
24 A. Well, I am not sure what you mean by distance
25 from water.

Q. The distance of a piece of property from a water source.

A. From a water main?

Q. Sure.

A. That would have some bearing. But you can also dig wells. So you can dig a private well and you may not have to worry about getting service to a particular, to a company or something like that.

Q. So I take it from your answer you suggest that access to water is not that relevant to land value and price?

A. It certainly is a factor, yes. But there are alternative ways of acquiring water service.

Q. Would you agree that there are alternative ways of acquiring electric generation apart from connecting to a utility's main extension line?

A. I don't know of any other way except if you are buying a generator or something like that.

Q. Access to property also influences the price of land and land value, correct?

A. Uh-huh.

Q. The availability of adequate sewer or septic facilities also influences the prices and land value?

A. Uh-huh.

Q. Do you mean yes?

1 A. Yes. Sorry.
2 Q. Sorry. The condition of surrounding streets,
3 paved versus unpaved for example, also influences land
4 value and sales prices, correct?
5 A. Yes.
6 Q. For residential properties, proximity to schools
7 and the quality of those schools would also influence
8 sales price and land value, correct?
9 A. Yes.
10 Q. And the use of surrounding land also influences
11 land value and sales price, correct?
12 A. Yes.
13 Q. In general, the location of property strongly
14 influences sales price and land value, correct?
15 A. Yes.
16 Q. Proximity to desirable conditions, such as a
17 popular shopping district, et cetera, would also
18 influence land value and sales price?
19 A. Yes.
20 Q. On the converse side, distance from developed
21 areas would also decrease sales price and land value,
22 correct?
23 A. Well, I don't know if it decreases, but it would
24 certainly affect the price.
25 Q. The topography of and ability to build on rural

1 land would also affect land value and sales price,
2 correct?
3 A. Yes.
4 Q. Did you attempt at all in your study to isolate
5 the potential economic impact of line extension policies
6 and differentiate them from any other influencing
7 factors?
8 A. No.
9 Q. If you could, turn to the table at the top of, I
10 am looking at -- I think it is reproduced a couple
11 times, but the one on page Romanette v. Is that
12 correct? No, I am sorry, Romanette iv.
13 A. Okay.
14 Q. I am wrong again. I am sorry. Romanette iii,
15 table at the top of the page.
16 A. Okay.
17 Q. Where did you get the data that generated this
18 chart?
19 A. Mr. Court dug up some of this information out of
20 APS annual reports. And there was a lot of
21 correspondence regarding the number of extensions that
22 were approved or permitted by APS over the last four
23 years. And I think some of it even came from Mr. --
24 Rumolo is it?
25 MR. RUMOLO: Rumolo.

1 THE WITNESS: -- Rumolo.
2 BY MS. GRABEL:
3 Q. Did you talk with anyone at APS personally when
4 preparing this report?
5 A. I did not, but Mr. Court spoke with various
6 people at APS, yes.
7 Q. To whom did Mr. Court speak?
8 A. Mr. Rumolo.
9 Q. Are you aware that the APS line extension policy
10 change that eliminated the free footage subsidy became
11 effective in July of 2007?
12 A. There were -- yes, it became effective in July,
13 but there was a phase-in period as well, yes.
14 Q. Please describe for me your understanding of the
15 phase-in period.
16 A. Well, I would have to probably get to the
17 specifics, look back at the actual service schedule.
18 But there was some allowances for if a person had
19 already executed an agreement or executed some
20 documentation with APS that they would be allowed to
21 continue forward. And there were certain dates. And
22 some of the dates allowed the transition to extend to
23 the middle of 2009, I believe, something like that.
24 Q. We refer to the provision that we just described
25 as the grandfathering provision?

A. Right.

Q. Apart from that grandfathering provision would you agree that the change that eliminated the free footage subsidy occurred for all other customers going forward in July of 2007?

A. Yes.

Q. The impact of that change would thus be reflected for the first full year in 2008, correct?

A. It possibly could have, yes.

Q. Please focus on the box of your table in the second row, fourth column, so not the caption extensions as a percent of customers but the first row in which you actually see numbers produced. And in the fourth column on the right, that fourth box in that row, it shows that customers who received line extensions comprised 9.5 percent of APS' total residential growth in 2008, correct?

A. Yes.

Q. And that same percentage of customers comprised only 6.9 percent of total residential growth in 2007, correct?

A. Right, yes.

Q. And the same customers comprised only 5.2 percent in 2006, correct?

A. Yes.

Q. And only 3.5 percent in 2005, correct?
A. Yes.
Q. Under your analysis, then, a higher percentage of APS' total customer growth sought and received line extensions from APS under the current policy that had eliminated the footage allowances than it had historically, not withstanding the change in policies, correct?
A. Other than some of, a portion of the extensions in 2008 could have been grandfathered. I mean we do not have, I do not have information on that.
Q. Your firm routinely analyzes current economic conditions and the reasons for those conditions, correct?
A. Uh-huh.
Q. And it includes in those analyses detailed descriptions of the housing market?
A. Yes.
Q. Factors that would influence the housing market?
A. Yes.
Q. Are you aware of any presentation or analysis that your firm has conducted that lists the change, and the elimination rather, of the line extension subsidies as a reason for the downturn in the housing market?
A. No.

Q. In your opinion would your firm have noted the impact of line extension policies on those market conditions had they been material?

A. Had they been material and brought to our attention, possibly, yes.

Q. Your firm has done such studies -- let me ask it this way: Has your firm done such studies since you have been retained to do this analysis?

A. Such housing studies?

Q. Yes, such --

A. Yes.

Q. -- analyses and the impact on the current state of the housing market.

A. Yes.

Q. I would like to ask you a few questions regarding your conclusions on the theory of substitution.

A. Yes.

Q. Assuming a buyer decides not to build on a residential lot because of the expense of constructing electric facilities. I read your report to suggest that they will either build in an area not impacted by that cost or purchase a lot in an undeveloped area, in an already developed area. Is that a correct summary?

A. Those are two potential consequences, or

1 alternatives, right.
2 Q. If the landowner chooses to purchase land and
3 build in a different area that still subsidizes line
4 extensions, the home construction would still occur,
5 correct?
6 A. Yes.
7 Q. So in that case, the more global economic impact
8 to Arizona that would result from this slowdown in
9 residential construction that you describe in section 5
10 of your report would not occur, correct?
11 A. Yes.
12 Q. And taking the second prong, assume the buyer
13 decides to purchase as a substitute a home in an already
14 developed area. Do you believe that that result is a
15 bad one from an economic perspective?
16 A. No.
17 Q. As a general proposition, would the economy be
18 better off if newly constructed homes were absorbed
19 rather than bypassing those current homes and developing
20 new areas in outer lying areas?
21 A. I am not so sure it is for me to say. I mean we
22 are generally free market economists, and if someone
23 wants to pay the price to move out farther, that's our
24 prerogative. But certainly, you know, I don't know if
25 it is a good or bad thing. It certainly happens and

1 people make those choices to not move out so far and
2 move in closer and where property is already served.
3 Q. Would it be more economically efficient for
4 current housing to be absorbed as opposed to letting
5 those lots lay vacant and developing new construction in
6 outer areas?
7 A. It would resolve the problem we have right now,
8 yes. It would help resolve the problem we have right
9 now with an oversupply of housing.
10 Q. And what would be the economic impact of
11 resolving that problem?
12 A. The economic impact?
13 Q. Yes. Will you please be more specific with the
14 problem you described and how absorbing the current
15 housing would fix that problem.
16 A. Well, we, we have an oversupply of housing right
17 now that is the major cause for the decline in housing
18 values. And if housing is, existing vacant housing is
19 absorbed, bought and occupied by people, certainly that
20 is going to help resolve the imbalance we have now on
21 the market.
22 Q. And if new development was to bypass existing
23 but vacant housing in favor of new builds, what would be
24 the impact on the property value implications for
25 current housing, currently existing housing?

1 A. Well, it would start to stabilize the value, and
2 eventually, as the supply is depleted, values would rise
3 to normal values.
4 Q. You understand based on Mr. Mumaw's prior line
5 of questioning that under the, actually just in general,
6 under the prior free footage line extension policies,
7 existing customers will require to subsidize new growth,
8 correct?
9 A. Yes.
10 Q. As a result of the policy change that removed
11 the subsidy, base electric rates for service paid by all
12 customers, both existing and current customers, will not
13 increase as much as they otherwise might, correct?
14 A. In theory, that's the idea, yes.
15 Q. If I represent to you that that is true, would
16 you --
17 A. Yes.
18 Q. -- believe me? In other words, there will be a
19 cost savings to consumers and businesses in already
20 developed geographic areas as a result of the policy
21 change, correct?
22 A. Yes.
23 Q. Have these cost savings been reflected in the
24 calculation of the economic impacts described in your
25 report?

A. No, they have not.

Q. Have you analyzed the economic impact of those cost savings at all?

A. No, we have not.

Q. If cost increases in certain geographic areas result in lower housing construction, but corresponding cost savings in other geographic areas result in more economic activity, is it possible that the economic activity generated from the cost savings would be sufficient to offset or exceed the economic losses related to the lower housing construction?

A. I couldn't make a conclusion like that.

Q. Why?

A. Well, I think it was just a lot of suppositions as to values and what the impact would be.

Q. You --

A. I really can't make a conclusion, can't come to a conclusion on it.

Q. You don't believe it would be possible at all for the cost savings to exceed or even offset the cost increases?

A. It possibly could. It possibly may not depending on the circumstances. I don't really know.

Q. Under what circumstances would it not?

A. Well, there are a lot of impacts that come from

1 new construction, employment, revenue that goes to the
2 cities and the state. I mean there is a lot of things
3 you would have to consider that new construction
4 generates. And whether that offsets other aspects, I
5 just, I really don't know.
6 Q. Would bringing in new businesses and new
7 employers to the state be an influencing factor in the
8 general overall economy?
9 A. Yes.
10 Q. And if you learned that prospective employers
11 looking to locate in Arizona were deterred by the cost
12 of electricity, would that be an influencing factor that
13 might offset the impact of housing construction?
14 A. Yes, it might, yes.
15 Q. Would you agree that the removal of subsidies
16 from all or part of the economy moves the economy
17 towards optimal efficiency, the most optimal
18 distribution of resources?
19 A. Yes, in general, it does.
20 Q. You note a couple of times in your report that
21 the elimination of the no cost extension to subsidize
22 growth is, at bottom, an issue of fairness, correct?
23 A. Yes.
24 Q. Based on the costs that you have reviewed for
25 the study, would you agree that extending service to

1 more rural and less dense property is more expensive
2 than extending service to less rural property with
3 smaller lots?
4 A. Well, I don't know the cost structure of that.
5 But in general, I think there is a lot of theoretical
6 and practical work that has been done in the area, and
7 higher density generally is more efficient than low
8 density development.
9 Q. So in your opinion it probably is more expensive
10 to extend a line out the further you have to go to
11 extend the line, correct?
12 A. Yes.
13 Q. Do you believe it is fair for landowners in
14 areas of higher density to subsidize landowners in lower
15 density areas?
16 A. I don't know if it is fair or not, to tell you
17 the truth. I mean there are various circumstances that
18 go into looking at these issues. And the issue of
19 fairness that we have dealt with is more revolved around
20 certain parts of the state, certain types of development
21 that really are now illiquid investments. And that is,
22 that is the issue that I think we really spoke to, is
23 the one of fairness and how there are certain people in
24 certain areas of the state that just do not have
25 alternatives like we have talked about previously. And

1 that's the fairness issue it comes down to.
2 Q. By removing the free footage subsidy, the
3 policies now require customers to pay their actual cost
4 of service, correct?
5 A. Yes.
6 Q. What is unfair about asking them to do that?
7 A. What is unfair is that they previously were not
8 asked to do that. And many people made decisions,
9 investment decisions based on that policy. And without
10 a whole lot of ability to input into that issue, they
11 now are dealing with a whole different set of
12 circumstances for developing their homes or selling
13 their homes or selling their lots, whatever it may be.
14 Q. Would you agree that governmental entities are
15 entitled to change their policies if they believe it is
16 necessary to do so?
17 A. Sure. They do it all the time.
18 Q. Would you agree people generally know
19 governmental agencies could change policies? They do it
20 all the time.
21 A. Sure. You are not a governmental entity,
22 though.
23 Q. The Arizona Corporation Commission is a
24 governmental entity, correct?
25 A. Yes.

Q. Do you personally believe that there is anything inappropriate about requiring a utility customer to pay his or her full cost of service?

A. As long as it is a reasonable cost of service, I think that it probably is fair for the, fair for people to pay their share of the cost. But there are no alternatives for some of these people in that APS holds a monopoly. They pay whatever charges are created by APS. In some circumstances it has created a lot of hardship for people.

Q. You raised the issue before and it is in your report that utilities other than APS have also eliminated the free footage subsidy, correct?

A. Uh-huh.

Q. And that they have done so as a result of a policy shift at the Arizona Corporation Commission, correct?

A. Uh-huh, yes. Sorry.

Q. Your report notes the differences in the amount of free footage allowances under the various utilities' past service schedules. APS had 1,000 feet. I believe UES had 400 feet.

A. Yes.

Q. And TEP had provided 500 feet.

A. Yes.

1 Q. Do you believe that those differences give rise
2 to any fairness issues?
3 A. Well, they were, they are the rules that were in
4 place at the time the change was made. So people made
5 their decisions based on what the rules were in those
6 service areas. And when the rules change, it does
7 create hardship. No matter whether it is 500 feet or a
8 thousand feet, there is still hardship that is created.
9 Q. As I understand what you are saying today is
10 that the fairness is not so much the amount that was
11 provided but the fact that it changed in general, is
12 that correct?
13 A. Yes. And in addition to that, in some instances
14 or some locations, like the more rural counties, there
15 are no alternatives for a lot of these people. They
16 can't go to a subdivision ten miles closer into the city
17 and buy a home. There just aren't the alternatives in
18 some of the more rural counties.
19 Q. If the prior APS policy had not allowed those
20 same residents you have just referred to to receive the
21 free footage subsidy, would it be unfair to not -- to
22 require them to pay that amount today?
23 A. If the rules are in place that people made
24 decisions on, then that, yes, that is, that is fine.
25 Somebody would know going in with their eyes open that

1 those are the rules of the game, so yes.
2 Q. Did any of the people -- do you have any
3 specific people in mind when you are referring to the
4 landowners in these rural areas that have no
5 alternatives?
6 A. Not specific people, but some of the counties
7 that we spoke to and received letters from that
8 expressed a lot of concern about the issue, La Paz
9 County, Coconino County.
10 Q. Are you aware of the individuals in general
11 about whom those interviewees referred, are you aware of
12 when those people would have purchased their properties?
13 A. No.
14 Q. Are you aware of whether or not they purchased
15 property that falls greater than a thousand feet outside
16 of -- a thousand feet from a currently existing electric
17 facility?
18 A. No. All I can tell you is the letters and
19 testimony we received of people caught in a, caught in
20 this particular situation.
21 Q. Your conclusion then that the change in policy
22 was unfair is based on the materials that have already
23 been provided to the Arizona Corporation Commission --
24 A. Well --
25 Q. -- correct?

1 A. To some extent, yes, and to our own just looking
2 at the situation and trying to, once again, get into the
3 head of a person who may be trying to make those
4 decisions or be in that position. And we have outlined
5 what we think some of the alternatives are. They would
6 do something different if the situation changed.
7 But there are some people who cannot make those
8 substitutions or alternative choices. And that's really
9 where it comes down to the issue of fairness. And it is
10 probably not, you know, in the overall sum of things, a
11 huge number of people, but it is people that are stuck.
12 Q. Do you believe a reasonable person could believe
13 that it is fair to change the policy under conditions
14 that might require so?
15 A. I don't know that I am really qualified to make
16 a conclusion on that.
17 Q. From what you just said, you were trying to get
18 into the head of the people who made the decision to
19 change the policy. So are there any circumstances under
20 which you might believe it is fair to do so?
21 A. The people who made the decision to change the
22 policy?
23 Q. Yes.
24 A. I think, I think it is fair. I mean that's --
25 utilities are basically following the way of government,

1 imposing impact fees and supposedly trying to make
2 development pay for itself. And in that regard, yes, it
3 is a reasonable matter to do so, to make that decision,
4 yes.
5 Q. Are you aware of APS' current financial
6 condition?
7 A. No.
8 Q. Are you aware of the impact of changing this
9 policy and eliminating the free footage subsidy on APS'
10 financial condition?
11 A. Not specifically other than I remember some
12 numbers in the report and some of the documentation we
13 received that, you know, it is in the millions of
14 dollars per year that were given away in free
15 extensions.
16 Q. Do you believe that the financial viability of
17 APS is important to the economic vitality of this state?
18 A. Sure, yes.
19 Q. Do you believe then that the financial condition
20 of APS should be a factor considered in assessing
21 whether or not the change in policy is fair to rural
22 landowners?
23 A. Yes. I think it is certainly a consideration.
24 Q. Did the change of policy impact any of your
25 company's current properties?

A. Well, it is my understanding it probably impacted all properties throughout the state or throughout the service area in one way or another.

Q. You have a strong role in assessing the value of the properties within your company's portfolio, correct?

A. In assessing the value?

Q. In managing the portfolio.

A. Managing, yes.

Q. And are you aware of whether or not the policy change has had any impact on any of those properties?

A. It has, other than this report, it has never come up, no.

Q. You never thought it was important enough to consider?

A. We didn't know about the policy.

Q. If you could, turn to page 19 of your report, APS Exhibit 1 for the record. You indicate in your report that most of the land represented in this table would have been allowed free line extensions under the prior APS line extension policy, correct?

A. That is what was provided to us by the group that we represent as our client.

Q. Your client provided you with the data in this chart?

A. Yes, yes.

Q. Did you research any of these properties independently?

A. We checked the, the price that was paid but we did not check the footage from existing service. We verified the pricing that was provided there.

Q. Is this the only data that Mr. Wyllie provided to you regarding --

A. Yes.

Q. -- these properties and these transactions?

A. Yes.

Q. And of this data, the only portion that you verified was the price, is that correct --

A. Yes.

Q. -- acres?

A. Price and acreage.

Q. Price and acreage.

Whether the landowners existing at these locations would have received line extensions depends on what equipment would have been required to complete the extension, is that correct?

A. Yes.

Q. And also from, the distance from the power source, correct?

A. Yes.

Q. Earlier in your report you recited costs for

1 line extensions from APS that were about 900 feet from
2 power as exceeding about 25,000. Do you recall that?
3 A. Yes.
4 Q. Similarly, you note that even a 400 foot
5 extension costs about $21,000, correct?
6 A. That's what I remember, yes.
7 Q. From your exchange with Mr. Mumaw you understand
8 that, if a customer reached that $25,000 cap, they were
9 required to pay the entire cost of the extension,
10 correct?
11 A. I was not aware of that.
12 Q. But you are aware of it now?
13 A. Yes.
14 Q. Looking at this chart, then, assuming that
15 somewhere between 400 and 900 feet falls the $25,000
16 amount, just to use a very rough approximate, a number
17 of these properties potentially were subject to -- a
18 number of the landowners who own these properties might
19 have been required to pay the full cost of the extension
20 even under the prior policy, is that right?
21 A. That may be, yes. I am not sure.
22 Q. When did each of the transactions listed on
23 page 19 of this report take place?
24 A. They were all in the -- there were two that we
25 could not confirm and the rest were in 2008 and 2009.

Q. How many transactions took place during the same time period in Maricopa County?

A. Land transactions? I don't know.

Q. You do not know?

A. No.

Q. Do you know how many took place in La Paz County?

A. No.

Q. Do you know how many took place took place in Pinal County?

A. No.

Q. I would like to focus your attention on two particular lots. Lot number 401-42-005-J, do you see that?

A. Yes.

Q. That one is 990 feet from power and cost $12,000. But the price per acreage was $9,600. Do you see that?

A. Yes.

Q. Why did that property cost more per acre than parcel number 504-34-064, which was only 660 feet from power?

A. Well, and that is why we really added the paragraph right below the table which explains that there are so many other intervening factors that enter

1 into the valuation of land that we did not go into a
2 detailed study to particularly focus on the impact of
3 the electrical extension.
4 Q. If I understand your answer, you are saying you
5 don't know what caused the difference?
6 A. No.
7 Q. Because many factors influence price?
8 A. It could be. Some of these are in very rural
9 areas with few houses around. Others are in more
10 built-up areas.
11 Q. In what other transactions might factors other
12 than distance from power have affected the sales price?
13 A. There are a number of -- all the factors we list
14 here, whether there is good access, paved access,
15 whether there is availability of water or sewer, septic
16 tank, percolation. There is any number of things that
17 go into a valuation of land.
18 Q. I think you might of misheard my question
19 slightly. In what other of the specific transactions
20 listed in this table might have factored, other than a
21 change in line extension policy or a line extension
22 policy in general, have influenced the sales price?
23 A. I am not sure what you are asking there. There
24 is lots of factors that would influence beyond just the
25 electrical extension.

Q. And that's true for every single one of these properties, correct?

A. Yes.

Q. Do you know whether all of these properties have water service?

A. No.

Q. Do you know whether all of these properties have sewer service?

A. No, but our assumption was they could dig a well and in most cases they will dig a well or dig a septic tank. Some areas I believe are served by Global Water. So there may be water service there from a company, but the alternative is to dig a well.

Q. Do you know whether all of these properties have access to city or county roads?

A. No.

Q. Do you know whether telephone service, either land line or cellular, is comparable amongst all of these properties?

A. No.

Q. Do you know whether each of these parcels get regular daily postal service?

A. No.

Q. Do you know whether each of these parcels receive regular trash pickup?

1 A. No.
2 Q. Do you know whether each of these parcels
3 benefit similarly from the availability of fire
4 protection?
5 A. No.
6 Q. Ambulance protection?
7 A. No.
8 Q. Police protection?
9 A. No.
10 Q. Do you know the total area in square miles
11 created by encircling these parcels with an imaginary
12 boundary?
13 A. No, I do not.
14 Q. Did you attempt to compare the sales price of
15 any of these parcels to a similarly situated parcel
16 located in an area served by a utility that still
17 provides a free footage subsidy?
18 A. No.
19 Q. Without isolating the discrete impact of the
20 elimination of the free footage subsidy or even
21 analyzing the other influential factors, can you
22 conclude with any reasonable certainty that the data in
23 this table suggests that distance from electric sales
24 has a negative effect on sales price?
25 A. No, we can't make that conclusion precisely.

Q. Can you conclude it with any reasonable certainty?

A. Not without further study.

Q. On page 19 of your report, the same page, in section 4.3 you conclude that policy changes to eliminate the line extension subsidies means that proximity to existing electrical service lines will likely be correlated with land value. And you note that the conclusion is based on interviews and letters of submission of various county assessors.

A. Yes.

Q. Are summaries of all those conversations summarized in this report?

A. No, I don't believe they are summarized.

Q. What other additional communications were there that are not summarized in this report?

A. There were direct phone conversations and there were letters. I mean there may be summaries of what was said. It is not like a transcript or more complete description of the conversations. It is a very quick summary.

Q. Do you have documentation of all the communications you had with the various interviewees?

A. I don't believe we have --

Unless you have notes.

They are summarized in the report, yes.
Q. All of them, sum total? Yes?
A. Yes.
Q. Thank you.
How many assessors did you speak with to reach the conclusion that proximity to existing electrical lines will likely be correlated with land value?
A. I believe we spoke to La Paz County and received letters from -- Yavapai County we spoke with.
Q. How did you determine to speak with the assessors of those two counties?
A. They have been, from what I understand, have been monitoring the situation, the electrical service schedule situation issue, and came to our attention through our clients.
Q. Your clients suggested that you interview those two people?
A. Yes.
Q. Did you interview anyone other than those you interviewed at your client's suggestion?
A. No.
Q. How long were your -- did you speak with these assessors personally?
A. No.
Q. Did Mr. Court speak with them personally?

A. Yes.

Q. How long were those conversations?

A. Can he speak?

Q. Sure.

MR. COURT: 15, 20 minutes.

THE WITNESS: 15, 20 minutes.

MR. COURT: For Yavapai County was based on the letters submitted, not an interview.

MS. GRABEL: What questions did you ask -- so let me understand this better, Mr. Court.

Did you give your information to the court reporter?

Let's do that at the end.

DANIEL COURT,

a witness herein, having been first duly sworn by the Certified Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

EXAMINATION

BY MS. GRABEL:

Q. Mr. Court, how many assessors did you personally speak with to provide data that allowed your company to reach the conclusion that the proximity to existing electrical service lines will likely be correlated with

1 land value?
2 A. Personally spoke with the assessor in La Paz
3 County.
4 Q. And how long was that conversation?
5 A. Likely 20 to 30 minutes.
6 Q. What questions did you ask him?
7 A. I asked him most basically if he believed that
8 the policy extension change was affecting the way that
9 they are valuating the land in their county.
10 Q. And how did he respond?
11 A. He responded that it was having, that the policy
12 change was affecting the way that they value land and
13 that it is devaluing land based on the proximity to
14 existing power.
15 Q. Do you know for how long that individual has
16 been the county assessor?
17 A. I do not.
18 Q. Did you ask how other factors might have
19 influenced his assessment?
20 A. Yes.
21 Q. And what was his response?
22 A. His response was that -- the main question that
23 I had was how do you separate the downturn in the
24 economy from the extension policy and the way that you
25 are valuing the land and noticing that you are assessing

1 value at a lower level. And his general response was
2 that both factors were playing a part in the assessment
3 of land, but it was his belief that the line extension
4 policy was having a significant impact on how they
5 assess land.
6 Q. Did you ask him what caused him to so conclude?
7 A. As an assessor, that is what -- I am constrained
8 to use him as an expert in knowing his field of
9 assessing land. And so his opinion or his opinion in
10 the interview is how we note, you know, a point.
11 Q. You are saying you deferred to his expertise in
12 assessing land?
13 A. Yes.
14 Q. And in his communications with you, did he list
15 any other factors other than the general real estate
16 market and the change in line extension policy that
17 would have influenced his assessment?
18 A. The conversation was directed toward the change
19 in the extension policy. So it was not a conversation
20 on how he assesses land. It was, it was a conversation
21 what the effect of, what any potential effect of a
22 policy change was having on valuation of land in his
23 county.
24 Q. Was he aware of any instance in which the change
25 actually decreased the value of land?

A. His responses are that policy changes are actually affecting the assessment of land.

Q. Did you ask him to give you any examples?

A. No.

Q. Did he indicate that there were such examples?

A. He indicated that the process in which they are assessing land is being affected by the line extension policy in a negative way.

Q. I am struggling to understand how. Do you know how?

A. I don't know how they are assessing land. I assume that they have policies and guidelines and standards to assess land.

Q. Okay.

A. And it is based on market value of land. I am assuming that.

MS. GRABEL: I will go back now to Mr. Merritt.

1 RICHARD CHARLES MERRITT,
2 a witness herein, having been previously duly sworn by
3 the Certified Reporter to speak the truth and nothing
4 but the truth, was further examined and testified as
5 follows:
6
7 EXAMINATION CONTINUED
8 BY MS. GRABEL:
9 Q. Is the sales data to which you refer in the
10 first paragraph of section 4.3 -- you talk about, this
11 is the third line from the bottom of that page, recent
12 sales data provided to this firm. Do you see that?
13 The sentence reads: Based on interviews and
14 letters of submission by various county assessors, in
15 addition to recent sales data provided to this firm --
16 which we know was provided to you by your client -- the
17 policy changes to eliminate free electrical line
18 extensions means that proximity to existing service
19 lines will likely be correlated with land value.
20 Do you see that?
21 A. Yes. Does that -- your question is whether it
22 relates to the table?
23 Q. My question is whether you have any sales data
24 other than that represented in this table.
25 A. Oh, no.

Q. And do you have any other evidence, apart from the interviews that we have described and that are summarized in this report and the data comprised of this table, to support the conclusion that proximity to electrical service lines will likely be correlated with land value?

A. No.

Q. Are you aware of any studies that have been conducted to analyze how county assessors are or may be treating parcels of land with electrical service compared to those without?

A. No.

Q. Do you have any specific data in this regard?

A. No.

Q. Assuming the accuracy of the conclusion that proximity to electrical service lines will likely be correlated with land value, wouldn't that conclusion have also held true under the old line extension policies?

A. To some extent, yes.

Q. With UES, any land more than 400 feet from electrical service, existing electrical service lines could potentially have been assessed a lower value than that within that 400 footage allowance?

A. Yes.

Q. And with TEP, any land further out than 500 feet from existing power facilities could have a lesser land value, correct?

A. Yes.

Q. And with APS, also any land further than 1,000 feet from existing electric service lines might have been assessed a lower land value, correct?

A. Yes.

Q. 1,000 feet is less than .2 miles, correct?

A. Yes.

Q. Would you agree that in low density rural areas identified in your report, individual lots are often .2 or more miles away from existing electric facilities?

A. I wouldn't have any way of knowing that. But it is my understanding that a development, home building, whatever it may have been, occurred incrementally within those guidelines. So instead of somebody building 2,000 feet away, they would buy a lot or build a home, whatever, within a thousand feet of electric service. And the next person would be then within that. Whether you are in APS territory or TEP territory, development, home building occurred kind of incrementally within those free extension policies.

Q. Did it also consider the $25,000 cap in your estimation?

1 A. Yes, I am sure it does.
2 MS. GRABEL: If I could go back to Mr. Court for
3 just one moment. I just have been reminded that the
4 La Paz County assessor, he is the individual with which
5 you personally had the conversation, correct?
6 MR. COURT: Yes.
7 MS. GRABEL: Mr. Nault?
8 MR. COURT: Yes.
9 MS. GRABEL: Your report says that Mr. Nault
10 stated that it is difficult to separate the effect of
11 the downturn in the economy from the APS policy change.
12 Do you remember that?
13 MR. COURT: Yes.
14 MS. GRABEL: Wouldn't it be true, if it is
15 difficult to separate the effect, then any analysis
16 regarding that effect would be largely hypothetical in
17 nature?
18 MR. COURT: Well, this is a summation of the
19 interview. It is not direct testimony. So the question
20 that I had previously told you was asking him how, how
21 they separate the downturn in the economy from line
22 extension policy, that he stated yes, it is difficult,
23 but based on all those interactions and his -- and in
24 assessing land, that the policy extension was having an
25 impact.

1 MS. GRABEL: He just couldn't give you a dollar
2 amount, is that how I am reading your answer? You said
3 it may generally have an impact but he couldn't tell you
4 by how much.
5 MR. COURT: Yes, there is no dollar amounts
6 discussed.
7 BY MS. GRABEL:
8 Q. Mr. Merritt, I would like to turn briefly to one
9 of the interviews in section 4.4 of your report. And
10 that is with Spencer Kamps of the Homebuilders
11 Association of Central Arizona. It is really the
12 statements and not so much the conversation that I am
13 going to ask you about.
14 Have you reviewed all of the statements that
15 Mr. Kamps made?
16 A. I have reviewed what is in the report, yes.
17 Q. You describe what is written here as a summary
18 of what Mr. Kamps' view, what Mr. Kamps said in his
19 interview. Do you agree with all of the statements that
20 Mr. Kamps made? Is this a reproduction just what he
21 said or is it a conclusion that your firm has drawn
22 based on that interview?
23 A. As far as I am aware, it is a summary of the
24 discussion.
25 Q. You do not represent that these interviews

1 themselves and the statements that Mr. Kamps made are a
2 conclusion drawn by your firm, correct?
3 A. No, no.
4 Q. You characterize many of the statements made as
5 based on perception and speculation. For example, you
6 say that, in the second real paragraph underneath the
7 first bullet, Homebuilders Association of Central
8 Arizona, it was also speculated that commercial
9 developments would likely face much larger costs due to
10 the electrical load that some commercial operations
11 require.
12 Did any of the interviews or Mr. Kamps
13 specifically offer any studies or analysis to support
14 their statements?
15 A. No.
16 Q. And to what extent is a landowner's or
17 developer's speculation about the cause of a condition
18 relevant to the economic proof of that condition?
19 A. Well, speculation is related to commercial
20 development and they are not in the commercial
21 development business. They don't represent commercial
22 developers. And I believe he was just making a note
23 that it is not only home builders that are affected but
24 also commercial development, businesses. I think it is
25 just, you know, some added knowledge that he may have,

1 he may know or may have heard about that is represented
2 here.
3 Q. You are not intending in this section to suggest
4 that public policy should change or be based on this
5 speculation that Mr. Kamps has made in that statement?
6 A. No.
7 Q. Did you ask Mr. Kamps to speculate on the
8 economic impact of the cost savings that those same
9 commercial operations would realize once connected to
10 the system in the form of lower rates?
11 A. I would have to go back to Mr. Court.
12 MS. GRABEL: Is the answer no?
13 MR. COURT: No.
14 BY MS. GRABEL:
15 Q. If you could, please look at the last paragraph
16 on page 21. The sentence begins overall it was
17 expressed that government related costs have not
18 corrected nor responded to Arizona's current real estate
19 market conditions.
20 Do you believe that public policy should be
21 based exclusively on its potential impact on the real
22 estate market in isolation of other considerations?
23 A. Well, once again this is Mr. Kamps' opinion in
24 the situation, so...
25 Q. I am asking you now personally. Do you believe

1 that public policy should be based exclusively on its
2 effect on the real estate market?
3 A. I think it should be a consideration certainly,
4 yes.
5 Q. Should it be the sole consideration?
6 A. No, but the real estate market is certainly a
7 major engine here. And government policy should take
8 that into consideration.
9 Q. Is Arizona's largest utility also a major
10 engine?
11 A. It is -- I don't know if I would call it an
12 engine from an economic perspective. It is, it
13 certainly helps the engine, but it is not the engine.
14 Q. Should the financial health of APS be considered
15 in making these kinds of policy decisions?
16 A. Certainly, yes.
17 Q. I would like to turn your attention to the last
18 sentence on this page: Additionally, the HBACA has been
19 informed by various parties that there is available
20 capital for real estate investment but the deployment of
21 that capital is awaiting the adjustment of governmental
22 costs before any such investment occurs.
23 Generally what do you understand this to mean?
24 A. What I think it means is that during the run-up
25 in the housing market, the governmental jurisdictions in

1 reaction to that had jumped on the task of raising
2 impact fees. And that also came along at the same time
3 that the service schedule did. And they are waiting,
4 the investors may be waiting for these fees now to be
5 adjusted downward so they are more reflective of the
6 situation.
7 Q. As you have just described it, do you believe
8 this suggests then that the current excess inventory of
9 homes and apartments is not the primary reason that the
10 real estate development has slowed so substantially?
11 A. Well, you were asking me what, I thought,
12 Mr. Kamps was saying. And I think that's what he is
13 saying.
14 As a representative of the home building
15 industry, you know, they are always out there looking at
16 impact fees as one of the major costs of housing. So it
17 does have an impact. It makes new housing certainly
18 less competitive with existing housing, that's for
19 certain, because of the size of the fees.
20 Q. I read that statement, and I think you have just
21 described it that way, as saying there is money out
22 there to invest in but we are not going to invest until
23 these governmental costs change, is that correct?
24 A. That's I believe what he was saying, yes.
25 Q. Are you aware of the basis for that assertion?

1 A. No.
2 Q. Are you aware of any other economist or any
3 economist that shares that view?
4 A. Well, I think there are probably home builders
5 out there that are having a difficult time selling
6 homes, building new homes and selling them in this
7 market, when the supply of homes, of existing homes, is
8 so large and cheap today.
9 Q. If the line extension policy changed back to the
10 way it used to be and there was no longer that
11 governmental fee, as some would describe it, but the
12 market stayed the same, would those people be in any
13 better predicament than they are now?
14 A. Probably not, no.
15 Q. Mr. Kamps suggests and others suggest, I
16 believe, in some of the summaries you have described
17 that a policy requiring the utilities' customers to pay
18 the full cost of a line extension is analogous to a
19 municipal or city impact fee, correct?
20 A. Yes.
21 Q. Would it surprise you to know that the suburb in
22 the greater metro Phoenix area that had highest number
23 of single family homes permitted in 2006 also had the
24 highest municipal impact fees?
25 A. No. In that kind of market you can get away

1 with a lot of things.
2 Q. Are you aware of the level of the impact fees
3 charged by municipalities and cities compared to that
4 assessed by APS now under its current line extension
5 policy?
6 A. Generally, yes.
7 Q. And what do you know about that?
8 A. Well, it depends if you are talking about an
9 impact fee in the tract subdivision versus an impact fee
10 in a rural area.
11 Q. Let's talk about rural areas.
12 A. Well, the impact -- well, in certain parts, most
13 parts of Maricopa County, unincorporated Maricopa
14 County, you pay very little, few impact fees. So the
15 main fee you would end up paying in this situation would
16 probably be the electrical extension fee. If you were
17 in a municipality, it is 20, maybe 20, 25 percent of an
18 impact fee, assuming that Mr. Kamps is representing
19 about $3,000 a unit for the new extension policy.
20 Q. Are you aware of any evidence that the APS
21 service territory has suffered a more significant
22 decline in housing construction than a similarly
23 situated area that has not seen the same change in line
24 extension policies, such as the SRP territory?
25 A. No, I am not aware of it. We did not conduct

that kind of study.

Q. Do you know, Mr. Merritt, what the costs are generally of building a well or a septic tank?

A. No, not off the top of my head, no.

Q. Can you approximate?

A. I don't even know if I could get in the ballpark.

MS. GRABEL: I think those are all the questions APS has.

Do you have any, Mr. Hains?

MR. HAINS: Yes. I actually have a couple, not very many, as you might imagine.

THE WITNESS: Okay.

MR. HAINS: Can everybody hear me all right from here?

Ralph, can you hear me?

MR. SMITH: Yes.

EXAMINATION

BY MR. HAINS:

Q. First, there is no particular order of these so hopefully I won't be bouncing around too much. But the first thing I wanted to ask you about was the calculation of the impact from the loss of 100 homes that you provided the -- approximately it was on, I

1 think it was in the table under 5.1.
2 You have it there for 100 homes at $180,000 per
3 unit. And you calculated that there would be a loss of
4 some of that profit margin that the builder would
5 experience due to these, this impact fee for the line
6 extension policy change. And I just wanted to ask you,
7 using that average of 100 and using the average cost of
8 the cost of extending power service by APS, does the
9 average cost of extending the service, does that
10 eliminate the profit margin under the averages that you
11 developed?
12 A. Well, we don't develop any profit margins or
13 anything in the information that I know of. We are
14 basically just talking about the average cost to build a
15 home and that type of thing. So we did not get into any
16 kind of profit margin analysis.
17 Q. So it is conceivable that it is possible that
18 even with the change in the line extension policy that
19 there still could be a profit realized on the sale of a
20 home because you haven't done an analysis to see whether
21 that might not be the case?
22 A. No, we haven't, right.
23 Q. Okay. Looking at the substitution period that
24 you discussed within your report, correct me if I am
25 wrong, but my understanding of the gist of the

1 discussion is that to a certain extent the choice of
2 where to purchase a home is elastic?
3 A. Yes, right.
4 Q. And to that extent, you understand that one of
5 the reasons, one of the positions that has been
6 forwarded by parties to the settlement is for a certain
7 revenue treatment for the Schedule 3 proceeds? Are you
8 familiar with that?
9 A. Well, just nothing more than what I heard this
10 morning so...
11 Q. Okay. But based on the understanding and
12 impressions you have gathered today at least, you
13 understand that APS is planning on receiving a benefit
14 from converting that into revenue treatment?
15 A. Yes.
16 Q. Okay. Based on that understanding, do you think
17 if, if the demand for housing is elastic under the
18 substitution theory, that there might be an elimination
19 of this benefit that APS is seeking under this
20 particular revenue treatment that it is requesting?
21 A. Well, I think certainly there would be an
22 impact, yes, I mean, and that it comes down to really
23 the crux of our analysis is that people in most
24 situations, particularly Maricopa County, have
25 alternatives. And it may lead to more efficient growth.

And if that's something the Corporation Commission wants to promote, that's their right to do so, I suppose. But there are any number of ways that a person can react to it. And it could have an impact on APS' bottom line, that you will not get as many extensions, cost extensions then because of this policy, yes.

Q. Okay. And I appreciate that response.

I wanted to ask a little bit about your understanding of how the old Schedule 3 worked, specifically the relationship between free footage and the power limit, the $25,000 limit. I wasn't clear if I understood that from your response earlier.

Were you not aware that there was the free footage to a thousand feet or up to a $25,000 limit before?

A. Yes, I did know that, yes.

Q. You did know that?

A. Yes.

Q. Okay. And with respect to, I know it is being termed as free footage here, but do you understand the rate treatment and how that panned out for APS in terms of it is not really free, that it is incorporated into the rate base for APS?

A. Yes, yes.

1 Q. And to that extent, do you have any knowledge of
2 how investors who look at APS look at or looked at how
3 APS was dealing with the growth in terms of the large
4 extensions to people in remote areas, and have you read
5 anything to the extent that there may have been concerns
6 that it may have been riskier for APS because of that
7 policy?
8 A. No, we did not look at that aspect. It was
9 beyond the scope of our study.
10 Q. Are you aware of any discussions to that extent?
11 A. No, we are not.
12 Q. Okay. Do you know or would you have an opinion
13 as to whether the prior extension policy had an impact
14 on APS' bond rating?
15 A. No.
16 Q. Okay. Do you know if it is, the new policy has
17 an impact on APS' bond rating?
18 A. No, I do not.
19 Q. Is it conceivable or would you have an opinion
20 whether eliminating, to the extent that there was a risk
21 associated with the prior policy, eliminating that risk
22 may have improved APS' outlook for the purposes of
23 evaluation by bond rating agencies?
24 A. No.
25 Q. Did you review any credit rating agency reports?

A. No.

Q. Do you have any idea what APS' present credit rating is?

A. No, I do not.

Q. Would you agree that if APS' bond rating were downgraded to a below investment grade that that would have a negative impact for Arizonans generally?

A. Generally, yes, I am sure it would.

Q. And in particular for people within APS' service territory?

A. Yes.

Q. And ratepayers of APS?

A. Yes.

Q. You also discussed somewhat the impacts to the public side from the change in the policy. I wanted to confirm what things that you looked at in terms of coming to your perspective on the benefits and the losses to the municipalities, excuse me, municipal entities at the various levels regarding the loss of 100 sales, 100 home units sold.

With respect to that, I just wanted to confirm, you did not look at costs to the municipalities of extending service to any of those lots?

A. No, we did not.

Q. You did not look at the cost of extending police

1 service?
2 A. No.
3 Q. Waste? Wastewater? Water?
4 A. No.
5 Q. No?
6 A. No.
7 Q. Have you any experience with or any knowledge
8 about the cost that could be associated with extending
9 service from the municipality out to these remote areas?
10 A. Well, it would -- no, I would not. Every city
11 is so different that you really couldn't make a
12 determination like that without a specific, looking at a
13 specific community.
14 Q. All right. Okay. I appreciate that
15 distinction. Let's take it like this: Did you -- is it
16 conceivable that the cost, the actual cost of materials,
17 of the labor and whatnot, for the municipality of
18 extending service to the same property being sold as
19 trying to be connected through APS, that you would agree
20 that does have a cost?
21 A. Yes.
22 Q. Okay. And to that extent, you did not evaluate
23 whether that cost may be greater because the property
24 lies in outlying regions?
25 A. No.

Q. Okay.

A. We did not.

Q. You agree that the cost does increase the further away from the point of service where the service is originating?

A. Yes, generally that's true.

Q. Okay. Did you evaluate whether the cost to the municipalities using the averages that you considered for the 100 units avoided -- excuse me, not avoided -- but the hundred units foregone if the cost to the municipality of extending service may conceivably exceed the lost revenues that would have been gained?

A. We did not consider that. But we have seen studies like that and take that into consideration. And our general conclusion is that homes and residents pay for a, pay for their service, and otherwise cities would go bankrupt. So in one way or another, the communities are making enough money off the various businesses and residents to have a positive effect on the community.

MR. HAINS: Sorry. I am just checking to see if my consultant has any more questions here.

I think that actually eliminates all the questions I have.

THE WITNESS: Okay.

MR. HAINS: You were too thorough, APS.

1 MS. GRABEL: We are good. Thank you very much,
2 Mr. Merritt.
3 I appreciate it, Mr. Court. Thank you. Last
4 minute impromptu witness.
5 (The deposition concluded at 11:32 a.m.)
6
7
8 RICHARD CHARLES MERRITT
9
10 DANIEL COURT
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1 STATE OF ARIZONA)
) ss.
2 COUNTY OF MARICOPA).

3 BE IT KNOWN that the foregoing deposition was
4 taken by me, COLETTE E. ROSS, Certified Reporter
5 No. 50658 for the State of Arizona, and by virtue
6 thereof authorized to administer an oath; that the
7 witnesses before testifying were duly sworn by me; that
8 the questions propounded by counsel and the answers of
9 the witnesses thereto were taken down by me in shorthand
10 and thereafter transcribed under my direction; that a
11 review of the transcript by the witnesses was requested;
12 that the foregoing pages contain a full, true, and
13 accurate transcript of all proceedings and testimony
14 had, all to the best of my skill and ability.
15 I FURTHER CERTIFY that I am not related to nor
16 employed by any of the parties hereto, and have no
17 interest in the outcome.
18 DATED at Phoenix, Arizona, this 3rd day of
19 August, 2009.
20
21
22 COLETTE E. ROSS
Certified Reporter
Certificate No. 50658
23
24
25

APS Exhibit _____

ARIZONA PUBLIC SERVICE COMPANY

Line Extension Data Requested in Letter of August 5, 2009

Individual Residential Line Extensions (Qualifying for 1,000 ft. free)*

	2005	2006	2007	2008	Total
Work orders under 1000 ft and under $25k	1,295	1,761	1,385	626	5,067
Average Cost	$7,736	$7,859	$8,982	$9,304	$8,313
Work orders over 1000 ft and under $25,000	193	253	158	74	678
Average Cost	$15,464	$16,085	$16,621	$16,717	$16,102

* Customer with extension over 1,000 ft. and under $25k could pay for distance over 1,000 ft.

Individual Residential Line Extensions by County

	2005	2006	2007	2008	Total*
Apache	0	1	3	0	4
Cochise	56	81	57	19	213
Coconino	120	130	104	85	439
Gila	31	64	37	19	151
Maricopa	445	567	425	229	1666
Navajo	95	96	215	89	495
Pima	2	6	5	4	17
Pinal	167	312	188	45	712
Yavapai	558	708	496	208	1970
Yuma	29	31	30	16	106
La Paz	19	97	45	26	187
Total	1522	2093	1605	740	5960

* All individual residential line extensions including those over $25,000

EXHIBIT
APS17
ADMITTED

Estimated Annual Investment in Line Extensions
(Includes Individual Residential, Subdivisions, Non-Residential)

	2005	2006	2007	2008
Extension $	$142 million	$167 million	$173 million	$119 million

Rate Impact if Current Extension Policy Had Been in Effect in 2005-2007

Reduction in Revenue Requirements*

	Reduction in Revenue Requirements	Impact on Avg. Residential Increase (Monthly)	Impact on Avg. E-32 General Service Increase (Monthly)
Schedule3 Proceeds Booked as Revenue	($173) million	($7.43)	($51.62)
Schedule3 Proceeds Booked as CIAC	($56.2) million	($2.34)	($16.32)

*If booked as CIAC, rate base would be reduced by construction cost but a portion of the reduction would be offset by the income tax rate base asset. Analysis based on plant additions 2005-2007.

If booked as revenue, the extension proceeds would reduce the revenue requirements in the test year used to set rates.

APS Exhibit 18

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
AK	Alaska Electric Power and Light	Fixed	• Residential Subdivisions and Trailer Parks: $1,000 per lot • Residential and Small Commercial Service: $2,000 per lot • Large Commercial: $7,500 • Harbor facilities: lesser of $7,500 or $500 per stall	Refund period: 5 years without interest	The policy contains a full set of requirements for extensions not built by AEPL.
	Alaska Power	Fixed	• All customers: $3,000	Refund period: 5 years as a credit to monthly bills, without interest	
AL	Alabama Power	Revenue	• Residential: 5x estimated annual revenue • Residential three phase: 3x estimated annual revenue • Commercial and Industrial: 3x estimated annual revenue • Farming: 5x estimated annual revenue • C&I&Farm three phase: equivalent of single phase allowance	Non-refundable	Policy contains specific cost calculations for underground extensions and above allowance costs.
AR	Entergy Arkansas	Footage	• Residential: 800 ft • Non-residential: Single phase: 1x estimated annual rev / 15% Three phase: 1x estimated annual rev / 30%	Non-refundable	Costs above allowance may be paid in monthly installments.
	Southwestern Electric (AEP)	Revenue	• Residential: No charge • Residential in undeveloped area: feasibility study	Non-refundable	Extension cost above allowance recovered either through advance or through minimum bills for 5 years.
CA	PG&E SCE SDG&E	Fixed and Revenue	• Residential: Total of "Distribution Line Extension" and/or "Service Line Extension" is: PG&E: $2,029 per meter or dwelling SCE: $1,951 per meter or dwelling SDG&E: $2,026 per meter or dwelling • Permanent Non-Residential, Seasonal or Intermittent Loads: $Allowance = \frac{Net\ Revenue}{Cost\ of\ Service\ Factor}$ • No allowance for emergency or "insignificant" loads.	Refundable amounts: cabling, substructures, pole lines, transmission underbuilds. Actual non-residential revenue reviewed for three years. Refund period: 10 years	Separate "Service Extension" Policy that covers facilities from Distribution Line (facilities at distribution voltages designed to supply more than two services) to Delivery Point. Includes service conductors and poles, service transformers, meters. Option to contribute 50% of refundable amount on a non-refundable basis.

EXHIBIT APS 18 ADMITTED

APS Exhibit _____

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
CO	Black Hills	Fixed	Separate line and service extension policies, each with separate allowances. Line Extension Allowances: • Residential: $0.84635/kWh • Non-Demand General Service: $0.91241/kWh • Demand Small General Service: $175.58/kW • Large GS Secondary: $212.74/kW • Large GS Primary: $141.54/kW • Large Power Service Secondary: $269.40/kW • Large Power Service Primary: $138.33/kW • Irrigation: $97.08/kW	Refund period: 5 years	Service Extension Allowances: Residential: $170.67 Non-Demand GS: $187.24 Demand Small GS: $640.66 Large GS Secondary: $1,116.07 Large Power Secondary: $2,148.55 Irrigation: $397.76 Customers will be given a photovoltaic system cost comparison when requesting cost of extensions.
	PS of Colorado (Xcel)	Fixed	Permanent Service (Plan A): Equivalent to gross embedded distribution plant investment per customer per rate schedule. • Residential: $720 • Residential w/demand: $110 plus $170/kW • C&I no demand: $1,150 • C&I w/demand: $1,110 plus $200/kW For schedules with demand charges, demand portion of the allowance is the estimate of kW load times derived gross embedded demand investment per kW.	Refund period: 10 years without interest	Plan A customers may contract to pay installments of various lengths for cost of extension over allowance. Plan B is Indeterminate Service and Plan C is Temporary Service, neither of which is granted an allowance.
CT	United Illuminating	Footage	• All customers: one span of overhead line	Non-refundable	Company may require guaranteed minimum annual payments.
DC	Potomac Electric (PEPCO)	Footage	Separate line and service extension allowances. • Residential: 200 ft for underground, overhead at no charge • Commercial and Industrial: No charge along public highways. If customer is only customer to be served from the extension, the customer will pay the cost of the extension.	Refund period: 10 years.	For service connections, residential customers are charged a flat fee of 50 cents per foot. Business customers pay for the entire service connection. Underground service allowance at equivalent of overhead service cost.
DE	Delmarva Power and Light	Footage and Revenue	Separate line and service extension allowances. • Residential: Service installation: 300 ft, line extension at 3x estimated annual revenue • Non-residential: 3x estimated annual revenue	Refund period: 5 years	Cost above allowance at average installed cost per foot for the prior year.
FL	Florida Power and Light	Revenue	• Overhead: 4x estimated annual base revenue • Underground: equivalent to overhead allowance	Refund period: 5 years for required deposits only	Extensions for large commercial loads that require additional facilities may be determined on a case-by-case basis.

APS Exhibit _____

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
FL	Gulf Power	Revenue	• Overhead: 4x estimated annual base revenue • Underground: equivalent to overhead allowance	Refund period: 3 years	
	Progress Energy Florida	Revenue	• Overhead: 4x estimated annual base revenue • Underground: equivalent to overhead allowance	Refund period: 3 years	At the end of one year, customers may request a refund calculation.
GA	Georgia Power	Revenue	• Residential: 3.5x estimated annual base revenue • Non-residential overhead: 3.5x estimated annual base revenue • Non-residential underground: 2.5x estimated annual base revenue	Refund period: 5 years	Residential underground requires an additional fixed payment per service point. As of 1/1/09, this charge was $575 per service.
HI	Hawaiian Electric	Revenue	Separate service and line extension allowances. Service Extension: • Overhead: one span of service connectors • Underground: equivalent to overhead allowance Line Extension: • All customers: 5x estimated annual revenue	Refund period: 10 years without interest	
IA	Interstate P&L (Alliant) MidAmerican	Revenue	Separate service and line extension allowances. Line Extension: • All customers: Estimated cost of construction less 3x annual expected revenue; feasibility study may be required	Refund period: 10 years without interest	Service Allowance: Overhead service lines are extended for 50 feet, underground service lines are extended for the equivalent of 50 feet of overhead; any additional footage requires a nonrefundable contribution.
ID	Idaho Power	Fixed	• Residential: All-electric: $1300 plus overhead terminal facilities (otf); other: $1000 plus otf • Residential Multiple Occupancy and non-demand general service: single phase: all otf, three phase: 80% of otf • Demand General Service: single phase: $1,726, three phase: 80% of otf • Irrigation: single phase $1726, three phase: all otf •General Service > 1MW: case-by-case • Non-Residential Subdivision: single phase: all otf, three phase: 80% of otf Overhead Terminal Facilities include transformer, meter, service cable and any conduit.	Refund period: 5 years and up to 80% of the original investment	Overhead Terminal Facilities are equivalent to the service connection. If allowance exceeds $75K, customer must contract annually for 5 years for the greater of:: Billing on appropriate schedule 80% of total annual bill 20% of allowance The policy includes specific costs for underground cable per foot.

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
ID	PacifiCorp	Footage and Fixed	Separate service and line extension allowances. Service Extension: • All customers: 100 feet from pole, connection box or transformer to point of delivery Line Extension: • Residential: Any costs in excess of transformers, meters, and service extension. • Less than 1MW: $90/kW of estimated load • 1MW or greater: $90/kW of estimated load with a 5-yr contract minimum billing and a termination charge related to Extension Allowance • 44kV or greater: Case by case	Refund period: 5 years; except for extensions within developments	Customers may choose to waive the right to receive refunds in exchange for a payment of $250.
IL	AmerenCIPS	Footage	Separate service and line extension allowances. Service extension allowance: • Residential: Overhead 150 ft, Undergrnd 100 ft. • General Service: feasibility study. Line Extension allowance: • Residential: 250 ft and one transformation • General Service: 250 ft and one transformation or at customers request, a feasibility study	Refund period: 10 years for cash payment; 5 years for non-cash payments	If Company believes revenue is meager or unlikely to develop, the extension will be reviewed by the Commission to determine reasonableness.
	Common-wealth Edison (Exelon)	Footage and Revenue	• All customers: The greater of: allowance equivalent to 250 ft of single phase overhead line per customer including transformation OR 1x annual delivery services revenue	Refund period: 10 years	Does not apply to lighting or standby service. Groups of 8 or more individual residential customers may choose a one-time non-refundable payment rather than a refundable deposit. Total cost of extension is defined in policy. If Company believes cost of extension is excessive, it will refer the matter to the Commission.
IN	Indiana Michigan Power (AEP) Duke Energy Indiana	Revenue	• All customers: 2.5x estimated annual revenue	Refund period: 6 years	Indiana Michigan: If Company believes revenue or eventual occupancy is doubtful, the matter will be submitted to the Commission for a determination as to public convenience and necessity. Customers can have the service extension built by a third party to Company specifications.

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
KS	KCPL	Footage and Revenue	Separate line and service extension allowances. Line Extension: • Overhead and rural residential: ¼ mile (1,320 ft) • All other: Feasibility study Service Connections: • Residential underground: equivalent to overhead • C&I underground service: 10 feet	Overhead and rural residential: no refund All other: 5 years	Customers may pay for footage above allowance in equal monthly installments for 60 months under contract.
	Westar	Footage and Revenue	Separate line and service extension allowances. Line Extension: • Overhead residential: ¼ mile (1,320 ft) • Underground residential: equivalent cost to ¼ mile of overhead • Commercial: 4x annual non-fuel revenue Service Connection: • Residential underground: equivalent to overhead • C&I underground service: 10 feet	Residential refund period: 5 years without interest Non-residential: No refund	Customers automatically billed for cost of extension above allowance in 60 monthly installments under contract.
KT	Duke Energy Kentucky	Revenue	• Overhead: 3x estimated annual revenue • Underground policy contains specific customer charges rather than allowances. Residential Developments: $2.15/ft Multi-Family Dwellings: No charge All other: Difference OH and UG cost	Refund period: 4 years	In difficult or rocky terrain, an additional $2 per foot may be charged.
	Kentucky Power (AEP)	Revenue	• Residential and small commercial single phase <25kVa: No charge • All other: 1x estimated annual revenue	Refund period: 5 years when contract is executed	
LA	Central Louisiana (CLECO)	Revenue	• Customers <300 kVa: 3x estimated annual revenue less fuel Customers >300kVa: feasibility study	Non-refundable	Additional cost is collected through facilities charges.
	Entergy New Orleans	Footage and Revenue	• All customers: 300 ft or 2x estimated annual revenue excluding adjustments	Non-refundable	
MA	Boston Edison	Revenue	Separate service and line extension allowance. Service Extension: • All customers: overhead, 100 ft of secondary wire; underground 2 feet into private property Line Extension: • All customers: 1.5x estimated annual revenue	Non-refundable	

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
MA	Massachusetts Electric (National Grid)	Footage and Revenue	• Residential: 150 feet or one pole, whichever is greater. Remainder at "Overhead Cost per Foot" calculated annually (currently $12.89) • Residential Developments: Overhead: 65 feet per house. Remainder at "Overhead Cost per Centerline Foot" calculated annually (currently $12.89); Underground: 35 feet per house. Remainder at "Underground Cost per Centerline Foot" calculated annually (currently $23.20) • General Service: 1x annual distribution revenue, including carrying charges and revenue apportionments	Refund period: 5 years	If residential cost is over $1500, payment may be made in installments. General service can request a refund recalculation in 12 to 36 months.
MD	Baltimore Gas and Electric	Footage and Fixed	Separate service and line extension allowances. Service Extension: • Residential Subdivision: 75 ft for single family, 30 ft for townhouse Line Extension: •Residential Subdivision: 200 ft plus 56% of cost of extension through large open areas • Non-residential: 50% of cost of total extension	Non-refundable	Policy contains per footage charges for costs above allowance.
	Potomac Electric (PEPCO)	Footage	Separate service and line extension policies. Line extension: • Residential: 200 ft for underground, overhead at no charge • Commercial and Industrial: No charge along public highways. If customer is only customer to be served from the extension, the customer will pay the cost of the extension.	Refund period for service extension: 5 years Refund period for line extension: 10 years.	Service extension fees: • Residential single family: $1,436 • Residential townhouse: $685 • Residential Multi-family: $497 • All others: total cost of extension Underground service allowance at equivalent of overhead service cost.
ME	Bangor Hydro	Fixed	Separate service and line extension policies. Line Extension: • None	Refund period: 20 years Cost of line is "reallocated" to all customers who previously paid for the extension.	Service Extension: provided at no cost. Line Extension: Company will extend up to 2,000 feet if Customer agrees to pay an additional monthly charge for 5 years.
	Central Maine Power	Fixed	Separate service and line extension policies. Line Extension: • Residential Low-Income customers receive an allowance which is the lesser of $2,800 or the extension cost • All other Customers: no allowance	Refund period: 20 years Cost of line is "reallocated" to all customers who previously paid for the extension.	Service Extension: provided at no cost. Policy includes a listing of specific line extension charges which must be paid by customer.

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DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
MI	Consumers Energy	Footage	• Residential: 600 ft, excluding service drop • Residential Subdivisions: 3x estimated annual revenue • General Service: 3x estimated annual revenue	Refund period: 5 years without interest	Underground service allowance at equivalent of overhead allowance. Contribution for residential underground developments at $3.50/ft, for general service underground at $10/kVa.
	Northern States Power (Xcel)	Footage and Revenue	• Permanent Residential: 600 ft, of which no more than 200 ft is a lateral extension on private property. Does not include service drop. • Seasonal Residential: 200 ft. • Commercial, Industrial, Street Lighting: 2x annual distribution revenue (for customers receiving service under a bundled schedule, 2x total annual revenue) • Questionable Permanence: No allowance	Residential refund period: 5 years Commercial, Industrial, Street Lighting: annual revenue estimate revised at end of 1st year, refund if warranted Questionable Permanence: annual refund based on percentage of actual revenue for 5 years without interest	A non-refundable contribution equal to right-of-way clearing is required. Additional charges apply for underground winter construction during the period Nov 15 to Apr 30.
MN	Minnesota Power (Allete)	Fixed	• Extension Cost < $30K: $850 or 3x guaranteed annual revenue with 5 year service agreement • Extension Cost > $30K: feasibility study • Developers: No allowance	Refund period: 5 years. Developers receive $850 refund for each connected customer	
	Northern States Power (Xcel)	Footage and Revenue	• Residential: 100 ft • Non-residential: 3.5x anticipated annual revenue less fuel cost	Refund period: 5 years for non-residential extensions where occupancy is delayed	Excess footage charges per circuit foot: Residential: $6.85 Non-res single phase: $6.98 Non-res three phase: $8.76 Additional charge for winter construction between Oct 1 and Apr 15.
MO	AmerenUE	Footage	• Residential: 1,000 ft plus service drop, meter, and transformer, no more than 500 ft on private property OR 1x annual estimated revenue • Residential Subdivisions: 150 ft per lot • Non-residential: 1x estimated annual revenue • Lighting: No allowance	Refund period: 5 years	Underground service allowance at equivalent of overhead allowance.
	Kansas City Power and Light	Footage	• Overhead and rural residential: ¼ mile (1,320 ft) • All other: Feasibility study	Overhead and rural residential: no refund All other: 5 years	Customers may pay for footage above allowance in equal monthly installments for 60 months under contract.
MS	Entergy Mississippi	Footage and Revenue	• Overhead: 600 ft plus 4x estimated annual revenue less fuel costs • Underground: equivalent of overhead allowance	Non-refundable	Cost above allowance may be paid through a facilities charge at Company's option.

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DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
MS	Mississippi Power	Revenue	• Residential: 5x estimated annual revenue • Commercial/Industrial: 3x estimated annual revenue • Underground: equivalent to overhead revenue calculation	Non-refundable	Additional expected revenue on an extension is included in revenue calculation for up to 5 years. Underground extensions may be eligible for additional credits on a case-by-case basis.
MT	Montana-Dakota Utilities	Revenue	• Subdivision Developers: No allowance • All other customers: 2x estimated annual revenue	Refund period: 5 years	Each contribution is trued up to actual cost at the end of construction and an additional charge or a refund is made.
	Northwestern Energy	Fixed and Revenue	• Residential: $500 plus service drop (150ft overhead, 100ft underground), transformer and meter • General Service <1MW: $0.04/kWh for estimated annual kWh consumption plus service drop, transformer, meter • General Service >1MW: Revenue/Cost Ratio; consisting of a comparison between the expected annual revenue and the annual cost of service	Refund period: 5 years	Does not apply to yard or street lighting service or temporary service.
NC	Duke Energy Carolinas	Fixed and Footage	• Residential Overhead: $10,000 • Underground: Residential < 1 acre: No charge Residential > 1 acre: 300 ft Non-residential: No charge Non-residential w/primary radial extension: single phase 300 ft; three phase 500 ft	Overhead refund period: 3 years for distribution equipment	
	Progress Energy Carolinas	Revenue	• Single phase: No charge • Three phase: Residential 5x estimated annual revenue less fuel charge, non-residential 2x estimated annual revenue less fuel charge • All Developments: 2x estimated annual revenue less fuel charge	Non-refundable	If connection is not at "normal" point of delivery, additional charges per foot apply.
ND	Montana-Dakota Utilities	Revenue	• Subdivision Developers: No allowance • All other customers: 2x estimated annual revenue	Refund period: 5 years	Each contribution is trued up to actual cost at the end of construction and an additional charge or a refund is made.

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
ND	Northern States Power (Xcel)	Footage and Revenue	Separate service and line extension allowances. Service Installation: • Residential: 100 ft • Non-residential: 3.5x anticipated annual revenue less fuel cost Line Extension: • All customers: 3.5x annual revenue less fuel cost	Refund period: 5 years for non-residential extensions where occupancy is delayed	Excess footage charges per circuit foot: Residential: $6.85 Non-res single phase: $6.98 Non-res three phase: $8.76 Additional charge for winter construction between Oct 1 and Apr 15.
NH	Public Service of New Hampshire Unitil Energy	Footage	All customers: 300 ft of overhead line extension	Refund period: 5 years	Underground allowance equivalent to overhead allowance. Except under unusual circumstances, line extensions only made between April 15 and November 15.
NJ	Public Service Electric and Gas	Revenue	• Non-growth area: No allowance • Growth area: 10x estimated annual distribution revenue • Smart Growth area: 20x estimated annual distribution revenue	Refund period: 10 years	
NM	El Paso Electric	Revenue	• All customers (when line extension built by EPE): 4 times annual revenue.	Refunds only available when actual annual revenue exceeds estimated annual revenue.	Company may sign a Revenue Guarantee in lieu of contribution. Accounts are reviewed on an annual basis.
	PNM	Fixed and Revenue	• Customers are eligible for either a revenue credit or a plat lot credit. The Revenue Credit is determined from the "Revenue Estimation Table" (not publicly available) and is related to estimated annual revenue. The Lot Credit is for subdivisions and is fixed from $50/lot to $400/lot dependent on overhead/underground service connections.	Non-refundable	
	Southwestern Public Service (Xcel)	Revenue and Fixed	• Residential: 1.25x expected annual revenue • GS extensions < $100K: 1.25x expected annual revenue • GS extensions > $100K: feasibility study • Irrigation and suburban developments: No allowance • Municipal and State streetlights: $486 per light • Customer owned streetlights: $70 per light	Non-refundable	Non-refundable contributions required to "prevent undue hardship on the other customers of the Company." Extensions made on a "suitable return" basis, defined as Company's most recent allowed rate of return.

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
NV	Sierra Pacific Power	Fixed	• Residential multi-family: $685 • Residential single family: $1,300 • General Service (no demand) secondary: $4,769 • General Service (no demand) Primary: $1,607 • General Service w/demand: per kVA allowance specific to rate schedule • Large GS: Covered in facilities charges • Master Planned Communities: None	Master Planned Communities: Refund period 10 years All Other Applicants: Refund period 5 years	Temporary Service (as defined by utility) covered under separate policy.
	Nevada Power	Fixed	• Residential multi-family: $410 • Residential single family: $1,176 • Residential three-phase: $8,540 • General Service: $1,763 • General Service w/demand: per kVA allowance specific to rate schedule • Large GS: None • Master Planned Communities: None	Master Planned Communities: Refund period 10 years All Other Applicants: Refund period 5 years	
NY	Consolidated Edison	Footage	Separate service and line extension allowances. Service Allowance: • Overhead Residential: 100 ft Line Extension: • Overhead Residential single phase: 500 ft • Overhead Residential three phase: 300 ft • Overhead Non-residential: single phase 500 ft, three phase 300 ft • Underground Residential (Mandatory): 100 ft total for both service and line extension • Underground All Others: equivalent of overhead footage cost	Refund period: 10 years	Amount above allowance may be paid through an annual surcharge for residential extensions. Surcharges are required unless new overhead distribution exceeds 1.5x revenue.
	New York State E&G	Footage	• Residential: Overhead at 500 ft of single phase or 300 ft of three phase of distribution line and 100 ft of service line; Underground where required at 100 ft of underground line • General Service: Overhead at 500 ft of single phase or 300 ft of three phase	Refund period: 10 years	Policy contains specific facilities cost per foot for underground costing
OH	Duke Energy Ohio	Footage	• All customers: 100 ft	Refund period: 4 years	Customers must contract for at least 4 years of service. Company may require minimum monthly payment equal to 1% of cost for residential and 2% for non-residential.

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
OH	Ohio Edison (FirstEnergy)	Revenue	• Residential: $5,000 • All others: Equivalent cost for 200 amp/single phase extension	Non-refundable	
OK	Public Service of Oklahoma (AEP)	Footage and Revenue	• Residential: 300 ft OR 3x estimated annual revenue less fuel; for energy efficient homes, 300 ft OR 4.5x estimated annual revenue less fuel • General Service: feasibility study • Underground Residential Developments: all equipment within primary cable limit of 100 ft per lot and service cable limit of 150 ft per lot	Refund period: 5 years	Residential customers may be subject to minimum bills.
OR	PacifiCorp	Fixed	• Residential: $750 • Residential in planned developments: $350 • General Service < 1MW: 2x expected annual distribution revenue • General Service > 1MW: 2x expected annual distribution revenue with termination charge within first 10 years • Non-residential planned developments: $400/lot	Refund period: 5 years	Customers may waive their right to receive refunds, and will receive a contract administration credit up to $250.
	Portland General	Fixed	• Residential: $1,514 • Non-Residential <30kW: $0.1129/annual kWh • Non-Residential >30kW secondary: $0.0524/annual kWh • Non-Residential >30kW primary: $0.0295/annual kWh	Refund period: 5 years	Allowance dollar amounts are listed in a separate rate schedule. Policy contains rules and regulations for conversion from overhead to underground.
PA	PECO Energy	Footage and Revenue	• Single Phase: 2,500 ft • Single Phase> 2,500 ft: 3x estimated annual revenue • Polyphase: 5x estimated annual revenue	No refund provisions	
	PPL Electric	Footage	• All customers: 2,500 ft	No time limit for waiver of minimum guarantee	If extension longer than 2,500 ft, minimum distribution revenue guarantee for 5 years is required.
RI	Narragansett Electric (National Grid)	Footage	• Residential: 2 spans and 2 poles plus the service drop, if underground the equivalent • Residential Development: 150 ft per lot not including the service drop • General Service: 2 spans and 2 poles plus service drop or equivalent cost if underground	Residential Refund period: 5 years General Service: one time recalculation between 12 and 36 months at customer request	If overhead residential cost above allowance is more than $6K, payments may be made over 5 years. Costs above allowance are per foot charges set forth in the policy. For general service, if calculated advance is less than $500, the Company will waive the cost.

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DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
SC	Duke Energy Carolinas	Footage and Revenue	• Overhead: economically feasible as determined by Company • Underground: Residential < 1 acre: No charge Residential > 1 acre: 300 ft Non-residential: No charge Non-residential w/primary radial extension: single phase 300 ft; three phase 500 ft	Non-Refundable	
	Progress Energy Carolinas	Revenue	• Single phase: No charge • Three phase: Residential 5x estimated annual revenue less fuel charge, non-residential 2x estimated annual revenue less fuel charge • All Developments: 2x estimated annual revenue less fuel charge	Non-Refundable	If connection is not at "normal" point of delivery, additional charges per foot apply.
SD	Black Hills	Revenue	• Residential: $2,000 • Residential all-electric: $3,000 • Residential w/demand: $5,000 • Residential seasonal: $1,000 • C&I: 4x estimated annual revenue	Refund period: 4 years If, after 4 years actual revenue is higher than estimated, 7% interest will apply to the difference.	Policy contains specific costs for equipment on which the cost of extension will be based.
	Northern States Power (Xcel)	Footage and Revenue	Separate service and line allowances. Service Allowance: • Residential: 100 ft plus 3x anticipated annual revenue • Non-residential: 3x anticipated annual revenue Line Extension: • All customers: feasibility study	Refund period: 5 years for non-residential extensions where occupancy is delayed	Excess footage charges per circuit foot: Residential: $4.65 Non-res single phase: $7.50 Non-res three phase: $9.50 Additional charge for winter construction between Oct 1 and Apr 15.
TN	Kingsport Power (AEP)	Revenue	• All customers: Extensions will be made based on sufficiency of revenue. Customers may be required to enter into a contract, monthly minimum charge, advance, or other means to justify extension.		No other information available to date.
TX	AEP Texas	Fixed	• Residential: $1,150 • General Service: $800 <10kW • General Service: $240/kW >10kW • General Service: $210/kW Primary Voltage	Refunds only available when actual annual revenue exceeds estimated annual revenue if cost of job >$25K.	Pilot Program Allowance for Subdivisions with Front of Lot Delivery Service: designed to provide incentives ($250 additional allowance) to developers of subdivisions containing more than 20 lots with lot sizes smaller than ½ acre to locate service in the front of the lots. The pilot runs through 1/1/2010.

DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
TX	Southwestern Public Service (Xcel)	Revenue	• Residential: 3x expected annual revenue excluding fuel and purchased power cost • GS extensions < $100K: 3x expected annual revenue excluding fuel and purchased power • GS extensions > $100K: feasibility study • Irrigation, suburban developments, and streetlights: No allowance	Non-refundable	Non-refundable contributions required to "prevent undue hardship on the other customers of the Company." Extensions made on a "suitable return" basis, defined as Company's most recent allowed rate of return.
UT	PacifiCorp	Fixed and Revenue	• Residential: $1,100 • Residential in planned development where service is already available at lot line: $350; otherwise $750 • Less than 1MW: Up to 16x annual revenue • 1MW or greater: Up to 16x annual revenue for at least 5 years with a 5-yr contract minimum billing and a termination charge related to Extension Allowance. • 46kV or greater: Metering necessary to measure usage	Refund period: 5 years	An Applicant may contract with someone other than the Company to build an extension. After transfer of ownership to the utility, the Company will reimburse the Applicant for the otherwise applicable extension allowance.
VA	Appalachian Power (AEP)	Footage	• Residential: 1,000 ft • Residential over 1,000 ft: 1,000 ft plus Company will pay $100 toward obtaining right-of-way • Non-Residential < 25kW: 150 ft • Non-Residential > 25kW: 1x estimated annual revenue less fuel plus carrying costs	Non-refundable	Underground allowance is the equivalent of the overhead allowance.
	Virginia Electric and Power (Dominion)	Revenue	• Residential single phase: No charge • Residential three-phase and Non-residential: 4x expected annual revenue less fuel cost • Other: in accordance with agreements on file	Non-refundable	
VT	Central Vermont Public Service Green Mountain Power	Fixed	All customers: Service drop allowance of $210	Refund period: up to 15 years	Green Mountain: Customer may elect to pay 50% of the advance in monthly installments over a period of 8 years.
WA	Avista	Fixed	• Consumption <72,000 kWh annually: Residential individual, $1,000; Residential duplex, $800/unit; Residential multiplex, $600/unit; General Service, $1300 ea. • Consumption >72,000 kWh annually: allowance individually evaluated	"Extension Certificates" provided which may be turned in for refunds within six years. Company makes a reasonable attempt to inform bearers when refund is due.	Policy contains specific equations for calculating extension costs for each consumption class and for extensions to developers. Policy also contains specific fixed and variable costs for facilities (such as circuits and transformers) to use in the equations.

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DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
WA	Puget Sound	Fixed	• Full-Time Residential: $1,117 • Part-Time Residential: $559 • General Service <50kW: $0.076430/kWh x estimated annual usage • General Service >50kW <350 kW: $0.063648/kWh x estimated annual usage • General Service >350kW: $0.050697/kWh x estimated annual usage • General Service at Primary: $0.031436/kWh x estimated annual usage General Service maximum allowance is $75,000	Refund period: 5 years	Allowances do not apply to the construction of service extensions. Policy contains specific facility costs to determine cost of line extension.
WI	Northern States Power (Xcel)	Fixed	Separate service and line extension allowances. Service Allowance: • All customers: no charge if not longer than recommended length for type of installation Line Extension Allowance: • Energy-only rate schedules: Residential and Farm: $360 General Service: $405 • Demand and energy rate schedules: $60/kW of estimated average monthly billing demand • Street lighting: $78 Seasonal service: half of applicable allowance	Refund period: 5 years	Amount of allowance is updated during rate proceedings.
	Wisconsin Electric	Revenue	• All customers: 5x average embedded cost to serve customers in the same class	Refund period: 5 years	Average embedded costs are recalculated on an annual basis and filed with the Commission. Installation charges apply to all extensions.
WV	Appalachian Power (AEP)	Footage	• Residential: 1,000 ft excluding service drop • Residential over 1,000 ft: 1,000 ft plus monthly line extension surcharge for 36 months • Non-Residential 1 – 99 kW: 4x annual revenue • Non-Residential 100 – 999 kW: 3.5x annual rev • Non-residential > 999 kW: 2.5x annual revenue	Non-refundable	Monthly line extension surcharge is based on the length of the extension. Underground allowance is the equivalent of the overhead allowance.

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DISTRIBUTION LINE EXTENSION REVIEW – INVESTOR-OWNED UTILITIES
RESEARCH UPDATED APRIL 2009

STATE	COMPANY	BASIS FOR EXTENSION	ALLOWANCE	REFUND PROVISIONS	DISCUSSION
WV	Monongahela Power	Footage and Revenue	Separate service and line extension allowances> Service Allowance: • All customers: 125 ft Line Extension Allowance: • Residential: 1,000 ft • Residential > 1,000 ft: 1,000 ft plus 9x estimated annual revenue • Non-residential: 9x estimated annual revenue	Non-refundable	Residential customers may choose to pay any advance as a monthly charge for 5 years. Plan includes specific charges for footage over allowance, updated annually.
WY	Cheyenne Light Fuel and Power	Fixed and Revenue	• Residential: $4,000 (single phase) • General Service: 4x estimated annual revenue	Refund period: 8 years	Any facilities in excess of those necessary to provide adequate service require an additional 30% over cost to cover ongoing costs such as insurance, taxes, etc.
	PacifiCorp	Fixed and Revenue	• Residential: $1,000 • Residential in existing development: $250 • Residential New Planned Developments: $750 • Less than 1MW: 1x estimated annual revenue • 1MW or greater: 1x estimated annual revenue with a 5-yr contract minimum billing and a termination charge related to Extension Allowance • 46kV and above: cost of meter necessary to measure the customer usage	Refund period: 5 years	Residential meters provided at no cost. Separate policy covers requirements for service entrances and connections.

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EXHIBIT

APS-19

ADMITTED

APS Exhibit _____

EXHIBIT
APS-20

Completed Residential Single Family Extension Work Orders

		La Paz County	Navajo County	Yavapai County
Year	Month	Colorado	Hopi	Yavapai/Apache
2008	Jan		2	
	Feb			
	March	1	5	
	April		3	
	May		2	
	June			
	July		7	
	Aug		4	
	Sept			
	Oct		4	
	Nov			
	Dec		5	
2008 Total		1	32	0
2009	Jan			
	Feb			
	March			
	April			
	May			
	June		1	
	July			
2009 Total		0	1	0

APS Exhibit _____

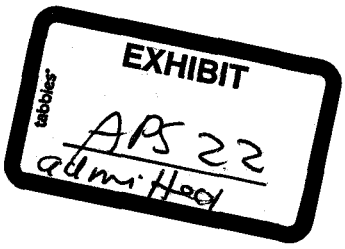
ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE 3 – LINE EXTENSION POLICY
HISTORY OF ALLOWANCES

EXHIBIT
APS-21
ADMITTED

EFFECTIVE DATE	ALLOWANCE
1/31/54 Initial Policy	Footage Basis: Both Residential and General Service 1,000 ft line extension allowance plus 150 ft service drop allowance plus No more than 1 service pole Extra footage cost: 75¢/ft line extension 25¢/ft service drop $45/pole Revenue Basis: General Service where: 1x estimated annual revenue = ½ cost of extension Allowance capped at $5,000
7/1/58	Footage Basis: Line extensions capped at 5,000 ft Revenue Basis: All extensions over 5,000 ft
4/30/62	Revenue Basis: 2x estimated annual revenue Allowance capped at $10,000
9/1/74	Footage Basis: Residential only 150 ft service drop allowance dropped 1 service pole requirement dropped Revenue Basis: Allowance capped at $25,000
7/26/82	Footage Basis: Listed footage charges deleted
7/1/07	Footage Basis: Dropped Revenue Basis: Residential allowance capped at $5,000 6x estimated annual distribution revenue for non-economic feasibility study extensions
2/27/08	All allowances dropped

APS Exhibit _____

Economic Statistics in Response to August 5, 2009 Letter from Chairman Mayes



Unemployment Rate[1]	
Arizona, July 2009	9.2%
US, July 2009	9.7%

Foreclosures	
All Types, Maricopa County, July 2009 YTD[2]	
Notices of Trustee Sale	63,667
Cancellations	(14,982)
Notices of Trustee Deeds	30,790
Total	79,475
Residential, Maricopa County, June 2009 YTD[3]	
Notices of Trustee Deeds	
Single Family Detached	19,887
Townhouse/Condominium	2,176
Total	22,063

APS Growth Outlook

	2010	2011	2012
Customer Growth	1.1%	1.2%	1.8%
Retail Sales Growth	1.9%	0.0%	0.1%

Sources:

[1] U.S. Bureau of Labor Statistics

[2] Maricopa County Recorders Office

[3] Phoenix Metro Housing Study, Arizona Real Estate Center, ASU

APS Exhibit _____

EXHIBIT
APS-23
admitted

Arizona Public Service Company
Disconnects Compared to Price Changes
2004 through 2009

Disconnect and retail price information is provided for the years 2004 through 2009. Table 1 provides the shut offs for non payments ("SONP") for June and July from 2004 through 2009. As shown, the SONP for June increased by 20.6% from 2008 to 2009, while the SONP decreased by 14.5% for July over the same period. The total change in SONP for June and July combined over the last year was 0.1%, which appears to be very stable. The relatively high year-over-year increase in SONP for June 2009 is likely due to the relatively mild weather, which resulted in fewer days where disconnects were suspended (due to severe weather). Conversely, for July 2009, the severe weather probably resulted in more days where SONP were suspended relative to a typical July.

Table 1. Shut Offs for Non Payment (SONP)
June and July, 2004 – 2009

	SONP June	% Increase	SONP July	% Increase	SONP Total June, July	% Increase
2004	3,628	NA	3,678	NA	7,306	NA
2005	3,594	-0.9%	3,024	-17.8%	6,618	-9.4%
2006	3,507	-2.4%	3,836	26.9%	7,343	11.0%
2007	3,953	12.7%	4,589	19.6%	8,542	16.3%
2008	3,648	-7.7%	5,137	11.9%	8,785	2.8%
2009	4,398	20.6%	4,394	-14.5%	8,792	0.1%

SONP information for all months from 2004 to 2009 is provided in Table 2. As shown, the annual SONP was 49,486 in 2006, it increased to 58,804 in 2007 and 63,040 in 2008, and is on pace for approximately 50,000 in 2009 (28,697 * 12/7). The SONP as a percent of total customers is also provided, which indicates that some of the increase in SONP is strictly due to the increase in total customers. SONP was 4.70% of total customers in 2006, 5.41% in 2007, 5.72% in 2008, and is on pace for approximately 4.5% in 2009 (50,000/1,109,597).

The number of turn ons for non payment ("TONP") is also provided for each year, which indicates how many of the SONP were ultimately restored to service versus those that permanently left the system, presumably due to the faltering economy or other reasons. As shown in 2008 and 2009 only about 55% of SONP were restored to service. The remaining 45% were not restored, which could indicate that many SONP resulted from customers leaving APS' system without terminating service (e.g. abandoning a home in foreclosure).

Table 2. Shut Offs for Non Payment (SONP)
Turn On for Non Payment (TONP)
Jan - Dec, 2004 – 2009

	2004	2005	2006	2007	2008	2009
Jan	3,193	3,106	3,622	4,090	5,290	4,654
Feb	2,854	3,025	3,674	3,677	4,652	4,122
Mar	3,367	3,711	3,759	4,298	4,986	4,233
Apr	3,610	3,212	3,184	4,397	4,830	3,806
May	3,066	3,309	3,446	4,549	4,380	3,090
Jun	3,628	3,594	3,507	3,953	3,648	4,398
Jul	3,678	3,024	3,836	4,589	5,137	4,394
Aug	4,392	4,742	5,337	6,340	5,853	
Sep	4,795	4,850	5,176	6,033	6,206	
Oct	4,160	4,797	5,717	7,501	7,518	
Nov	3,846	4,338	4,450	5,601	5,275	
Dec	3,121	3,356	3,778	3,776	5,265	
Total SONP	43,710	45,064	49,486	58,804	63,040	28,697
TONP	NA	NA	16,616	35,891	34,882	15,967
SONP less TONP			32,870	22,913	28,158	12,730
TONP as % of SONP	NA	NA	33.58%	61.03%	55.33%	55.64%
Total SONP	43,710	45,064	49,486	58,804	63,040	28,697
Average Monthly Customers	966,266	1,007,718	1,051,895	1,086,328	1,101,905	1,109,597
SONP as percent of AVG Customers	4.52%	4.47%	4.70%	5.41%	5.72%	2.59%

The changes in base rates and PSA for 2004 through 2009 are provided in Table 3. The information is shown as dollar per kWh and year-over-year percentage change. The PSA information is provided on an end-of-year basis. The combined annual change in the base rates and PSA ranges from 14.52% in 2006 to -1.22% in 2008.

Table 3. Base Rates and PSA, 2004 – 2009

	End of Yr PSA $/kWh	Base Rates $/kWh	Base Rates and PSA $/kWh	Base Rates and PSA % Change	Base Rate Increase	End of Yr PSA Adjustor	End of Yr PSA Surcharge 1	End of Yr PSA Surcharge 2	End of Yr PSA Interim	End of Yr PSA Forward	End of Yr PSA Historic
2004	$ -	$ 0.076359	$ 0.076359	0.00%							
2005	$ -	$ 0.079572	$ 0.079572	4.21%	x						
2006	$ 0.011554	$ 0.079572	$ 0.091126	14.52%		x	x		x		
2007	$ 0.005163	$ 0.090250	$ 0.095413	4.71%	x	x		x			
2008	$ 0.004000	$ 0.090250	$ 0.094250	-1.22%						x	x
2009	$ 0.005338	$ 0.092510	$ 0.097848	3.82%	x					x	x

A side-by-side comparison of the annual change in SONP and prices is provided in Table 4. and Graph 1.

Table 4. Base Rates and PSA Versus SONP
Annual Percentage Change 2004 – 2009

	SONP	Base Rates + PSA
2005	-9.4%	4.21%
2006	11.0%	14.52%
2007	16.3%	4.71%
2008	2.8%	-1.22%
2009	0.1%	3.82%

Graph 1.

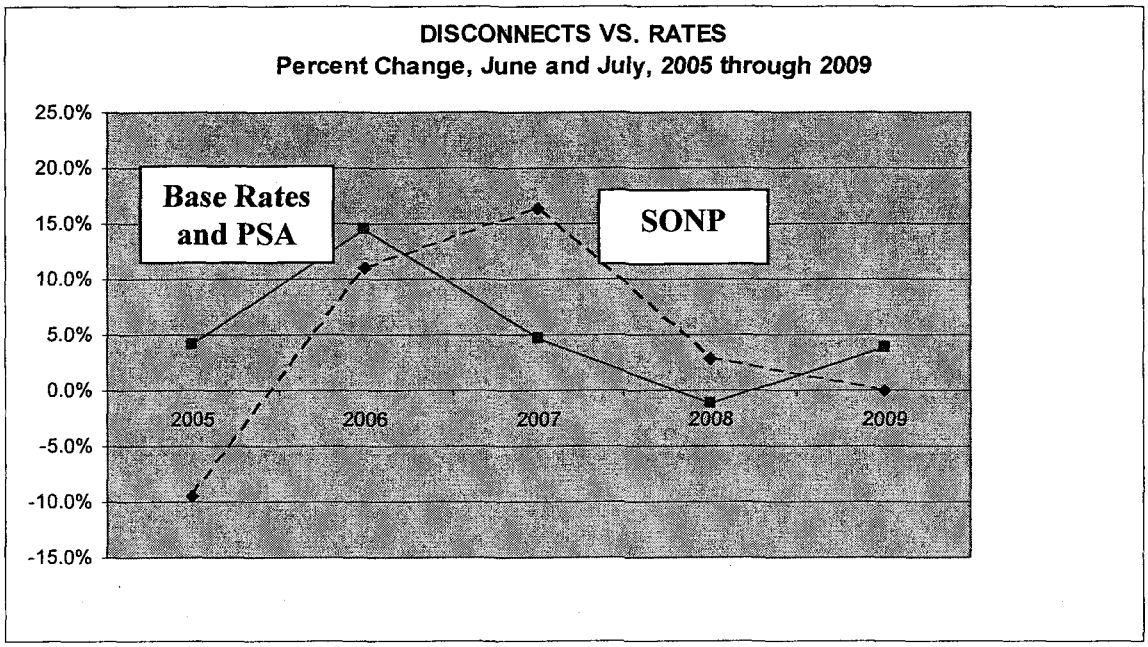


EXHIBIT
APS-24
ADMITTED

DIRECT SETTLEMENT TESTIMONY OF BARBARA D. LOCKWOOD

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

July 1, 2009

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DIRECT TESTIMONY OF BARBARA D. LOCKWOOD
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Barbara D. Lockwood. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Arizona Public Service Company ("APS" or "Company") as the Director of Renewable Energy. In that position, I am responsible for APS's renewable energy programs including generation planning, customer programs and policy.

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. I hold a Bachelor of Science degree in Chemical Engineering from Clemson University and a Master of Science degree in Environmental Engineering from Georgia Institute of Technology. I am a registered professional chemical engineer in Arizona, and I began my career in the chemical industry at E.I. DuPont de Nemours ("DuPont") in various engineering and management roles. Subsequent to DuPont, I worked in the consulting field and managed diverse projects for national clients across the United States. I have been with APS since 1999.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address the settlement provisions related to Renewable Energy, specifically Section XV of the Settlement Agreement. My testimony is

organized into four primary areas: (1) the overall renewable energy goals; (2) in-state wind and photovoltaic renewable generation procurement related provisions; (3) distributed energy related provisions; and (4) cost recovery.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. One of the goals of the Settlement Agreement is to advance sustainable decisions related to Arizona's energy future. APS strongly supports the Settlement Agreement and continues to promote renewable energy development and implement initiatives that go beyond the requirements in the Renewable Energy Standard ("RES") Rules. Under the Settlement Agreement, APS will acquire by the end of 2015 new renewable resources that provide 1,700 gigawatt hours ("GWh") of renewable energy annually. Along with existing commitments, this is double the amount of energy required under the RES. In meeting that objective, APS will develop a plan to adopt a utility scale photovoltaic project, issue a request for proposal ("RFP") for an in-state wind generation project, develop a proposal for distributed solar projects for Arizona K-12 schools, and develop a proposal for distributed solar energy projects aimed at governmental institutions. The Settlement Agreement also provides for timely cost recovery through existing rate mechanisms.

Q. WILL YOU BE ADDRESSING THE PROVISIONS IN THE SETTLEMENT AGREEMENT RELATED TO THE CONSTRUCTION OF RENEWABLE TRANSMISSION?

A. No. APS Witness Jeff Guldner will be addressing all renewable transmission provisions of the Settlement Agreement.

III. RENEWABLE ENERGY GOALS

Q. DOES APS SUPPORT THE COMMISSION'S RES?

A. Yes. APS believes the standard has done much to further the application of renewable resources in the state, encourage the development of the renewable resource industry to supply such resources, and provide some regulatory clarity to utilities and market participants. The Company does not, however, believe it is appropriate or necessary to adopt the current RES in the Settlement Agreement or in this Docket. Adopting the RES in this proceeding could create the possibility of conflicting requirements in the future and could limit the ability of the Commission to make certain changes in future RES Implementation Plans.

Q. PLEASE DESCRIBE THE RENEWABLE ENERGY GOAL IN THE SETTLEMENT AGREEMENT.

A. Under the Settlement Agreement, the Company will make its best efforts to acquire new renewable energy resources with annual generation or savings of 1,700 GWh annually by December 31, 2015. These new renewable resources are in addition to existing resources or commitments as of the end of 2008 as identified in APS's 2008 annual RES Compliance Report[1] and will include a mix of distributed and non-distributed resources.[2]

Q. HOW DOES THIS GOAL BENEFIT THE CUSTOMER?

A. As a result of the Settlement Agreement, the Company has now made a commitment to a specific result – namely, the acquisition of 1,700 GWh of

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[1] Docket No. E-01345A-07-0468 (April 1, 2009).

[2] The Company's recently filed request for approval of a Power Purchase Agreement with the proposed CSP resource Starwood Solar I will, when approved, contribute approximately 900,000 MWhs toward this goal (Docket No. E-01345A-09-0261, filed May 22, 2009).

renewable energy resources on an annual basis by 2015. The Settlement Agreement provides a balance between specific commitments and the Company's general plan to include renewable resources as a significant part of its future resource needs.

Additionally, as set forth in Paragraph 15.8 of the Settlement Agreement, the Company is obligated to follow through with this acquisition of 1,700,000 megawatt-hours ("MWh") of renewable energy by 2015 regardless of the outcome of any judicial challenge to the RES rules. This paragraph assures both customers and the Commission that APS will continue to pursue feasible renewable energy as the Company acquires resources to meet future load.

Q. PLEASE EXPLAIN WHY THE 1,700 GWH RENEWABLE ENERGY TARGET ADOPTED BY THE SETTLEMENT AGREEMENT IS REASONABLE?

A. The overall energy target is consistent with APS's long-term renewable resource acquisition plans that were included as part of APS's Resource Plan Report[3]. In addition, the renewable energy requirement will exceed the requirements under the RES. Under current estimates, the new renewable acquisitions, in combination with existing renewable commitments are approximately the equivalent of 10% of retail sales by the end of 2015, or double the RES requirement of 5%.

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[3] Docket No. E-01345A-09-0037 (January 29, 2009), Appendix 1.

Q. HOW ARE RENEWABLE RESOURCES BEING DEFINED?

A. Renewable resources are being defined consistent with the definition of "Eligible Renewable Energy Resources" included in the RES in A.A.C. R14-2-1802.

Q. ARE THERE ANY REPORTING REQUIREMENTS IN THE SETTLEMENT AGREEMENT REGARDING RENEWABLE ENERGY?

A. Yes. APS will report to the Commission on the Company's plans and progress toward acquiring these new resources in APS's annual RES Implementation Plans, RES Compliance Reports, and in future resource planning filings. Aligning the Settlement renewable energy reporting requirements with the existing RES reporting provides consistency and efficiency. Should there be any expected delays or shortfalls in meeting these renewable energy requirements, APS will also notify the Commission consistent with this reporting requirement.

IV. <u>WIND AND PHOTOVOLTAIC GENERATION</u>

Q. PLEASE DESCRIBE THE SETTLEMENT PROVISIONS RELATED TO WIND AND PHOTOVOLTAIC ("PV") GENERATION PROCUREMENT.

A. The Settlement includes an in-state wind requirement. Under this provision, APS will issue an RFP for in-state wind generation within 90 days of Commission approval of the Settlement. After evaluating the proposals, within 180 days of the issuance of this RFP the Company will file a request for Commission approval of one or more of these projects and will proceed as quickly as is feasible with any authorized wind generation project.

Under the PV requirement, APS will file for Commission consideration a plan for implementing a utility scale PV project within 120 days of Commission approval of the Settlement. The project will have a construction initiation date

no later than 18 months from the date of APS's filing of the plan. This commitment is in addition to the Concentrating Solar Power ("CSP") project, Starwood Solar I, purchased power agreement that was recently filed with the Commission for approval.

Q. WHAT GUIDELINES DOES THE COMPANY FOLLOW TO ENSURE THAT THE PROCUREMENT PROCESS IS FAIR AND UNBIASED?

A. As part of the Company's procurement strategy, and pursuant to the REST Rules,[4] APS has had its Renewable Energy Competitive Procurement Procedures ("Procurement Procedures") reviewed and certified by an independent auditor.[5] The Procurement Procedures identify the policies and procedures APS will use to procure renewable energy through both RFP and bilateral purchase approaches. APS utilizes these procedures as part of its procurement strategy and has adopted the use of an independent third party to review the Company's RFP process to assess whether it was conducted in a fair and unbiased manner. Since the Procurement Procedures were certified, APS has issued four renewable solicitations and procured over 2,100 GWh in renewable energy.

Q. IN WHAT MANNER WILL APS SEEK COMMISSION APPROVAL FOR EACH OF THESE PROJECTS?

A. As discussed later in this testimony, APS will file for Commission approval of these resources through either 1) a separate application, 2) as part of the Company's annual REST Implementation Plan, or 3) as part of the Company's Resource Plan.

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[4] A.A.C. R14-2-1812(B)(6).

[5] 2007 Renewable Energy Procurement Solicitation Certification FINAL REPORT, Presented to Arizona Public Service Company, April 10, 2007, Navigant Consulting.

V. DISTRIBUTED ENERGY

Q. PLEASE DESCRIBE THE SETTLEMENT PROVISIONS RELATED TO DISTRIBUTED ENERGY.

A. The Settlement Agreement includes provisions for the installation of distributed on-site solar energy at grades K through 12 of public (including charter) schools ("Schools Solar Program") resulting in 50,000 megawatt hours of annual energy generation or savings within 36 months of Commission approval of the Schools Solar Program.

The Settlement Agreement also includes a provision for APS to file a distributed solar energy program for Governmental Institutions. Neither of these two groups of customers can take advantage of tax credits, which impacts their ability to participate in the current program. Both programs have a goal to help eliminate up-front customer costs, and they will include distributed solar technologies including photovoltaics, solar water heating, and daylighting.

Q. WHAT TYPE OF CONSIDERATIONS WILL BE TAKEN INTO ACCOUNT WHEN PRIORITIZING PROJECTS UNDER THE SCHOOLS PROGRAM?

A. APS will collaborate with the School Facilities Board ("SFB") in determining the priority of projects. In the process, APS and the SFB will give consideration to the assessed valuation of the school district, participation in the National School Lunch Program, geographic diversity, and the need for the project.

Q. HOW WILL THE COMPANY APPLY FOR COMMISSION APPROVAL OF THE SCHOOLS PROGRAM AND THE GOVERNMENTAL INSTITUTIONS PROGRAM?

A. APS will file with the Commission its Schools Solar Program and Governmental Institutions proposed program under a new docket number within 120 days of a Commission order approving the Settlement. Under the Schools Solar Program

the application would include an estimate of costs associated with the program, a proposed method for cost recovery as provided for in Section XV of this Agreement, and APS's proposal for counting the energy towards APS RES requirements. In designing the program, APS will consider as part of its options a request for proposal by developers to implement and install solar energy systems on multiple schools such that schools pay no up-front costs.

Under the Schools Solar Program, APS will provide an opportunity for interested stakeholders including school representatives and solar industry representatives to provide input into the Company's proposed School Solar Program. Under the Governmental Institutions Program, APS will also provide an opportunity for stakeholder input on the proposed Program and the Program may be filed concurrently with the Schools Solar Program.

Q. DOES APS HAVE EXPERIENCE WORKING WITH THE SCHOOLS TO ENCOURAGE RENEWABLE ENERGY INSTALLATIONS UNDER THE COMPANY'S EXISTING RENWABLE PROGRAM?

A. Yes. APS has worked with schools in the development of renewable resources through school participation in the Company's renewable energy incentive programs. As well, schools have bid into the RFP processes for distributed renewable projects. The Company has also worked with the Schools and related organizations through the implementation of energy efficiency measures.

Q. WOULD SCHOOLS RECEIVING FEDERAL STIMULUS FUNDING UNDER THE AMERICAN RECOVERY AND REINVESTMENT ACT BE COUNTED TOWARDS THE SCHOOL SOLAR PROGRAM GOAL?

A. Yes. School programs executed with RES funds and leveraged with federal stimulus funding would qualify toward meeting the RES program goal.

Q. HAS THE COMPANY REVIEWED CALIFORNIA'S "FEED-IN" TARIFF PROGRAM AS MENTIONED IN CHAIRMAN MAYES' LETTER TO THE PARTIES DATED JUNE 9, 2009?

A. Yes. California Public Utilities Commission Resolution E-4137 authorizes utilities to purchase eligible renewable generation from public water and wastewater facilities. Briefly, the resolution approved tariffs which will offer set market prices, by time-of-use hours, for a period of 10, 15 or 20 years for the sale of renewable generation to the utility from eligible facilities. The program is available until the statewide capacity of these purchases reaches 250 megawatts ("MW"). Projects are capped at either 1 MW or 1.5 MW depending on the utility.

Q. WOULD THE COMPANY SUPPORT SUCH A PROGRAM?

A. Although APS does not believe a feed-in tariff is the optimal approach for encouraging customer investment in renewable energy systems, APS would not oppose a pilot program for this type of renewable purchase program for small renewable generation projects.[6] As indicated, APS believes that procuring this type of renewable energy would likely be more costly (and therefore of lesser benefit to APS customers) than if acquired through the Company's established competitive solicitation process. For example, costs proposed in responses to the Company's 2008 distributed energy RFP are approximately half the price of APS's standard incentive program. Additionally, APS recently issued an RFP requesting renewable projects of similar size, and is currently evaluating the

[6] It is important to note, however, that the kWh's generated by this type of project will not qualify to be counted toward a Distributed Renewable Energy Requirement as the RES rules are written today.

responses to that RFP. The results of this RFP will be communicated to the Commission in APS's 2009 Compliance Report.

If the Commission would like to explore this type of program further, APS suggests that it be considered in the renewable energy Implementation Plan process, thereby giving all stakeholders an opportunity to have input to the program design and consider broader program implications.

Q. HOW MANY MW SHOULD BE TARGETED UNDER SUCH A "FEED-IN" PROGRAM?

A. The objectives of this program would need to be clearly defined to establish MW targets. If the goal of such a program were to encourage additional distributed generation, the energy requirements under the distributed energy portion of the RES could provide guidance. Another consideration in determining the size of the program would be the amount of funding required.

As mentioned, it would be productive to discuss this potential program in the RES Implementation Plan process in conjunction with all other RES program elements.

Q. IS THERE A NEED TO ESTABLISH A "CARBON TRUST FUND" AS SUGGESTED BY CHAIRMAN MAYES?

A. APS believes a "carbon trust fund" is not necessary. Today, the Company does not systematically "bank" carbon credits as a separate asset. Such credits are included in Renewable Energy Credits ("RECs") that the Company currently banks to be used to satisfy the long-term RES requirements. To date, the Company has not sold any RECs; however, if those credits were to be sold, the funds generated through such a sale would be returned or credited to the customer through the RES or another appropriate mechanism. Therefore, the

Company believes that a trust fund for carbon credits would add an unnecessary layer of complexity and cost to the acquisition of renewable energy resources.

VI. COST RECOVERY

Q. HOW WILL THE COMPANY RECOVER COSTS ASSOCIATED WITH THE RENEWABLE PROVISIONS IN THE SETTLEMENT AGREEMENT?

A. As provided for in Section XV of the Agreement, APS will recover all prudent expenses incurred for renewable energy provisions under the Settlement through the Power Supply Adjustor ("PSA"), RES, or the Transmission Cost Adjustor ("TCA"). Depending on project scope and cost, APS will file for Commission approval of these resources as a separate application, as part of the Company's annual RES Implementation Plan, or as part of the Company's Resource Plan. APS will evaluate the appropriate cost recovery mechanism on a case-by-case basis; but as a general proposition, the recovery of renewable energy purchased power agreements would be split, as is presently the case, between the RES and the PSA. Program costs such as rebates, financing cost buy-downs, and administrative costs would be recovered through the RES. Transmission related costs would flow through the TCA.

Q. WILL CAPITAL CARRYING COSTS BE RECOVERABLE UNDER THE AGREEMENT?

A. Yes. Prudently incurred program expenses related to renewables in the Settlement Agreement will include capital carrying costs of any capital investments made by APS, including depreciation expenses at rates established by the Commission, property taxes, and a return on both debt and equity at the pre-tax weighted average cost of capital.

Q. IS THE TOTAL COST ASSOCIATED WITH THE RENEWABLE ENERGY PROVISION CONTAINED IN THE AGREEMENT IDENTIFIABLE AT THIS TIME?

A. No. The total cost to implement the provisions of the Settlement Agreement are unknown at this time and will depend on many different variables including the types of programs that are ultimately adopted by the Commission. The Commission will have an opportunity to review these costs as APS comes to Commission for approval of the resource acquisition or renewable energy programs adopted under the Settlement Agreement.

VII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Advancing sustainable decisions relating to Arizona's energy future is a goal of this Settlement Agreement. Under the Agreement, by the end of 2015, APS will acquire new resources annually providing 1,700 GWh of renewable energy; doubling the amount of energy required under the RES Rules. To meet this requirement, APS will develop a plan to adopt a utility scale photovoltaic project, issue a RFP for an in-state wind generation project, develop a proposal for distributed solar projects for Arizona K-12 schools, and develop a proposal for distributed energy projects aimed at governmental institutions. The Agreement also acknowledges the Company's need for timely recovery of the costs related to these projects, and includes a process by which these costs can be recovered through existing rate mechanisms. APS continues to promote renewable energy development and implement initiatives extending beyond the requirements set forth by the RES Rules and strongly supports this Settlement Agreement.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT
APS-25
ADMITTED

DIRECT SETTLEMENT TESTIMONY OF JAMES M. WONTOR

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

July 1, 2009

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DIRECT SETTLEMENT TESTIMONY OF JAMES M. WONTOR ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is James M. Wontor. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR POSITION WITH ARIZONA PUBLIC SERVICE COMPANY?

A. I am manager of the Demand-Side Management Team for Arizona Public Service Company ("APS" or "Company"). In that capacity, I manage the planning and implementation of all of the Company's energy efficiency programs.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold a Masters Degree in Business Statistics from Arizona State University and a Bachelors Degree in Business Management from the University of Montana. I currently manage the Demand Side Management ("DSM") Programs for APS. These programs include both the Residential and Non-Residential energy efficiency programs, as well as the Commercial and Industrial demand response program. I am responsible for the design and implementation of all DSM programs, as well as the regulatory compliance reporting for these programs. I have held this position since September of 2007.

Prior to that time, I served as Manager of the Company's Load Forecasting function for 6 years, where I was responsible for preparing the Company's long

range forecast of electric customers, sales, and revenues, as well as monitoring both the U.S. and Arizona economies.

My experience also includes 3 years as Director of Customer Care for APS Energy Services, the deregulated subsidiary of Pinnacle West Capital Corporation. In that role, I directed the metering and billing aspects of providing competitive energy service to business customers in both Arizona and California. Prior to that, I was Manager of Customer Research for APS; doing both market and load research with electric customers throughout the state of Arizona.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Settlement Testimony is to address the provisions outlined in the Joint Parties' Settlement Agreement ("Settlement") related to the Company's DSM endeavors. Specifically, my testimony describes four DSM-related areas in the Settlement: 1) the Energy Efficiency ("EE") savings goals for 2010 to 2012; 2) the 2010 Energy Efficiency Implementation Plan; 3) the enhancements to APS's current energy efficiency portfolio that will be implemented as a result of the Settlement; and 4) the estimated program costs and recovery of program costs and incentives through a modified DSM Adjustment Charge ("DSMAC").

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. Through this Settlement, Arizona and APS are taking another major step forward in advancing Arizona's sustainable energy future through the enhancement of DSM programs and measures. This Settlement establishes the first energy savings goals for any Arizona utility, a step that further integrates energy

efficiency into the portfolio of resources that APS uses to serve the energy needs of its customers. The energy savings goals embodied in the Settlement modify the current approach to DSM implementation, which is now based on annual spending targets. The annual savings goals begin in 2010 and will accumulate to an overall savings of approximately 3.75% of the Company's total energy resources needed to meet retail load in 2012.

Concurrent with these aggressive energy efficiency goals, the Settlement also modifies the current DSM performance incentive. The proposed incentive encourages performance over and above the annual efficiency savings goals by offering increased incentives as the goals are met and exceeded. It also provides for reduced incentives if the savings goals are not met. The proposed performance incentive is calculated as a percent share of benefits delivered to customers, but it is also capped at a percent of program cost to ensure certainty.

Meeting these higher efficiency targets will clearly require enhancement to some current DSM programs, as well as the implementation of new energy saving measures. The proposed program enhancements include the following:

- Residential High Performance New Homes
- Residential Existing Home Performance
- Low Income Weatherization
- Non-Residential High Performance New Construction
- Non-Residential Customer Repayment Financing
- Schools Program Target
- Large Customer Self-Direction

To implement these and future program enhancements in an efficient and timely manner, the Settlement requires APS to submit an annual Energy Efficiency Implementation Plan for Commission consideration, which will include proposed programs along with the estimated funding levels needed to reach the proposed energy savings targets and a proposed DSMAC rate to achieve such funding.

The Signatories to this Settlement also have agreed that it is reasonable to modify APS's DSMAC in order to achieve more current recovery of program costs, similar to the DSM adjustment mechanism the Commission has approved for Tucson Electric Power Company. This change is an important first step in addressing the regulatory challenges associated with increasing the energy efficiency impacts that are inherent for a regulated utility.

III. ENERGY EFFICIENCY SAVINGS GOALS AND PERFORMANCE INCENTIVE

Q. PLEASE EXPLAIN THE ENERGY EFFICIENCY SAVINGS GOALS CALLED FOR UNDER TERMS OF THE SETTLEMENT?

A. The goals establish a percent of energy resource needs that should be met through the implementation of energy efficiency measures. Stated in another way, a certain percentage of customers' energy needs will be served through efficiency savings, rather than from any power generating source. If adopted as part of this Settlement, the goals represent the first such energy-based efficiency targets established for any Arizona utility.

Q. WHAT ARE THE SPECIFIC ENERGY EFFICIENCY SAVINGS GOALS THAT ARE ESTABLISHED IN THE SETTLEMENT?

A. The proposed cumulative MWh savings from energy efficiency programs for 2010-2012 is 1,210,000 MWhs. Listed below are the annual incremental

savings goals for each of those years and the percent of energy resource needs they represent.

	Annual[1] Savings	Percent of Total Energy Resources
2010:	320,000 MWhs	1.00%
2011:	400,000 MWhs	1.25%
2012:	490,000 MWhs	1.50%
3-Year Total:	1,210,000 MWhs	3.75%

Q. HOW DO THOSE TARGETS COMPARE TO WHAT APS HAS ALREADY ACHIEVED WITH ITS ENERGY EFFICIENCY PROGRAMS OR TO WHAT OTHER STATES ARE DOING?

In 2008, APS achieved net savings of approximately 254,000 MWh from its energy efficiency program portfolio. The target of 320,000 MWh in 2010 represents a 26% increase over the level achieved in 2008 and the 490,000 MWh target for 2012 represents a near doubling of the anticipated annual program impacts under the status quo. Cumulatively, the goal of 1,210,000 MWhs from 2010 to 2012 is a significant increase over the 565,000 MWhs that have been saved from 2005 to 2008.

In regards to the achievements of other states, I have not conducted my own independent review of the various energy efficiency programs. However, according to a March 2009 report by the American Council for an Energy-Efficient Economy, the 14 "top states" in energy efficiency performance had a median savings of 0.7% of their MWh sales in 2007. Note that a percent of sales figure is less than the percent of total energy resources target used in the

[1] These annual MWh savings will result in 1) an estimated $1.1 billion reduction in program participant total electric bills over the life of the measures installed and 2) reduced CO2 emissions by approximately 6 million tons.

Settlement. The annual targets established in the Settlement of achieving 1.00%, 1.25%, and 1.50% of total energy resources in 2010, 2011, and 2012, respectively, is significantly higher than the median for these leading states.

Q. HOW DO THE ENERGY EFFICIENCY GOALS DIFFER FROM WHAT APS CURRENTLY HAS AS ANNUAL TARGETS?

A. The savings goals represent a significant shift away from the emphasis on the annual DSM spending budget that has existed since 2005. Currently, the Commission sets annual spending targets for APS, and the Company is tasked with implementing the most cost effective DSM that can be achieved within that budget. The establishment of energy savings goals modifies this approach by requiring that DSM be driven by meeting the energy savings goal each year and then estimating the program budget necessary to achieve the goal.

Q. HOW DO THE SAVINGS GOALS IN THE SETTLEMENT COMPARE TO WHAT APS EXPECTED TO ACHIEVE IN THE ABSENCE OF SPECIFIC GOALS IN THE SETTLEMENT?

A. In the absence of energy savings goals in the Settlement, APS identified in its Resource Plan Report filing on January 29, 2009 (Docket No. E-01345A-09-0037), a possible action plan for implementing a cost effective level of energy efficiency based on known costs and technology. The targets set forth in the Settlement accelerate the level of energy savings identified in APS's Resource Plan by approximately four years.

Q. HOW DO THE REQUIREMENTS OF THE SETTLEMENT AGREEMENT AFFECT THE ONGOING GENERIC PROCEEDING ON ENERGY EFFICIENCY IN DOCKET E-00000J-08-0314?

A. Currently there is an energy efficiency rule-making process under way for Arizona which would include an energy efficiency standard, but acceptance of

this Settlement Agreement would establish the first ever energy efficiency goals for Arizona, a goal that would be in place regardless of the outcome of the current Commission rulemaking process. If, however, a higher energy efficiency savings standard was adopted in the rule making process, then it would supersede the proposed savings goals in the Settlement.

Q. HOW DOES THE AGREEMENT CHANGE THE CURRENT PERFORMANCE INCENTIVES FOR APS?

A. The performance incentive under this agreement has been modified to better align the incentives with the goals. The Settlement provides for a tiered performance incentive that increases as higher percentages of the goal are reached or exceeded. As illustrated in Table A on the next page, the first performance incentive tier begins if the Company achieves at least 85% of the annual goal. If the Company achieves savings below 85% of the goal, then no performance incentive would be earned. Above the 85% threshold, the performance incentive increases as a larger portion of the goal is achieved and it reaches its maximum if APS achieves over 125% of the annual goal. At each performance achievement level, the performance incentive is calculated as a percent of net benefits to the customer and capped at a percent of the program costs. For example, if the annual savings goal was exactly achieved, the performance incentive would be 7% of net benefits, capped at 14% of program costs. In contrast, the current incentive structure is 10% of net benefits capped at 10% of program costs, regardless of the level of savings achieved. Thus, this new incentive structure requires APS to focus on programs with the highest net benefits to APS customers if it wishes to maximize its potential incentive payments.

TABLE A

Achievement Relative to the Energy Efficiency Goal	Performance Incentive as % of Net Benefits	Performance Incentive Capped at % of Program Costs
Less than 85%	0%	0%
85% to 95%	6%	12%
96% to 105%	7%	14%
106% to 115%	8%	16%
116% to 125%	9%	18%
Above 125%	10%	20%

IV. 2010 ENERGY EFFICIENCY IMPLEMENTATION PLAN

Q. WHAT IS THE ANNUAL ENERGY EFFICIENCY IMPLEMENTATION PLAN REFERENCED IN THE SETTLEMENT AGREEMENT?

A. The Settlement requires APS to file an annual implementation plan outlining the Company's proposed Energy Efficiency portfolio. The comprehensive Energy Efficiency Implementation Plan ("EEIP") will include, for the Commission's consideration, new programs and/or the expansion or enhancement of current programs necessary to achieve the energy targets for the following year. The EEIP must also contain the expected savings by program, as well as the range of proposed funding, by program, necessary to meet the energy savings targets. It also will include a proposed DSMAC rate to provide that funding, albeit on a partially lagged basis because the rate would not become effective until March 1st of the Plan year. The first such Implementation Plan (for 2010) will be filed on July 15th, 2009.

Q. WHAT PROGRAM FEATURES IS THE 2010 IMPLEMENTATION PLAN REQUIRED TO INCLUDE?

A. The Settlement directs APS to include the following in its initial EEIP:

a. A residential high performance new home program element with a second tier of performance and a higher customer financial incentive, which APS will file with the Commission on or before June 30, 2009;

b. A Home Performance program element within the Existing Home HVAC program. APS will design this program element with the goal of serving at least 1,000 existing homes by December 31, 2010;

c. A review of the APS low income weatherization program for possible enhancement;

d. A non-residential high performance new construction program element with a second tier of performance and a higher customer financial incentive;

e. A customer repayment/financing program element for schools, municipalities, and small businesses fully integrated in the non-residential programs; and

f. A goal for APS to serve, through its existing DSM programs or enhanced program elements, at least 100 schools by December 31, 2010.

Q. WHY IS THE EEIP BEING FILED BEFORE THE APPROVAL OF THE SETTLEMENT?

A. The Settlement requires aggressive levels of energy efficiency to be achieved in 2010. For those levels to be achieved, the EEIP must be approved concurrent with the Settlement so that the new program elements can be in place as early in 2010 as possible. The Settlement provides that Staff will review the Plan and:

> ...provide its recommendations to the Commission, in sufficient time so that the Commission may consider these matters at its regular November

Open Meeting. In an effort to achieve timely approval of the Plan, the Signatories urge the Commission to take action on the Implementation Plan on or before the date it takes action on the Agreement. Such Implementation Plan will make clear that its obligations therein are contingent upon Commission approval of the Agreement. *See* Proposed Settlement Agreement dated June 12, 2009, page 30.

Q. IN YOUR OPINION, SHOULD THE IMPLEMENTATION PLAN REPLACE CURRENT REPORTING REQUIREMENTS?

A. Yes. The current reporting requirements will become redundant and unnecessary once the Implementation Plan is approved, as the Implementation Plan will encompass all of the information presented by the current reporting requirements, but will be combined into one filing. The current reporting requirements that will no longer be necessary include the 3-year portfolio plan filing, the semi-annual DSM reports, the annual conservation report, and the Demand Side Management Adjustment Charge recovery request.

V. NEW PROGRAMS AND MEASURES

Q. HOW DOES APS EXPECT TO MEET THESE GOALS FROM 2010 TO 2012?

A. In order to meet these goals, APS will have to expand the existing portfolio of programs and introduce new EE programs and measures, as agreed to in the Settlement.

Q. WHAT NEW PROGRAM ENHANCEMENTS WILL BE INTRODUCED WITH APPROVAL OF THE SETTLEMENT AND THE IMPLEMENTATION PLAN?

A. APS will be proposing to introduce the following program enhancements in 2010: a residential high performance new construction program element, a home performance program element, additions to its current low income weatherization program, a non-residential high performance new construction

program element, a customer repayment financing feature, and a specific target for the number of schools served. In addition to these elements, additional enhancements may be proposed in future years.

Q. WILL YOU PLEASE DISCUSS THE SETTLEMENT'S PROVISION FOR RESIDENTIAL HIGH PERFORMANCE NEW CONSTRUCTION HOMES?

A. The high performance new construction measure was filed with the Commission on June 29, 2009 in compliance with Decision No. 70666. The program represents a significant step towards the goal of "zero net energy" homes, requiring an energy efficiency improvement of at least 30% compared to a standard new construction home. This is twice the energy savings than the current ENERGY STAR construction measure. APS will combine the marketing of this program with renewable energy incentives for builders to encourage the development of energy efficient and solar communities that reduce energy use by 50% or more.

Q. WHAT IS THE HOME PERFORMANCE PROGRAM ELEMENT REFERENCED IN THE SETTLEMENT?

A. The Home Performance Program element will be a comprehensive on-site home energy efficiency assessment and retrofit program. It will be delivered by certified home performance contractors, who will use tools such as blower doors, duct blasters and infrared cameras to assess a home's energy efficiency. The program will bundle several cost-effective measures such as whole house air-sealing, duct sealing, attic insulation, shade screens, and direct installation of compact fluorescent light bulbs and low flow fixtures to offer a customized package of efficiency improvements that can attain significant savings per household. The program will be based on the national EPA/DOE Home

Performance with ENERGY STAR program framework which has been implemented successfully in several other states. By combining targeted marketing and consumer education with the brand awareness and successful program framework of the national ENERGY STAR program, APS has agreed to reach at least 1,000 existing households with this program by the end of 2010.

Q. WILL YOU PLEASE DESCRIBE THE SETTLEMENT'S PROVISION REGARDING THE LOW INCOME WEATHERIZATION PROGRAM?

A. The Settlement calls for a review of the low income weatherization program for possible enhancements. APS plans to conduct such a review and recommend possible enhancements for 2010 in the EEIP. Potential enhancements may include changing the income guideline for program qualification, expanding the measures included in the scope of weatherization activities, and providing funding for multi-family public housing facilities.

Q. WILL YOU PLEASE DISCUSS THE SETTLEMENT'S PROVISION FOR THE NON-RESIDENTIAL HIGH PERFORMANCE NEW CONSTRUCTION PROGRAM ELEMENT?

A. This proposed program element is designed to encourage developers to implement additional EE measures in newly constructed buildings. Incentives are designed to increase as the building exceeds baseline efficiency levels. This tiered approach will encourage and enable the adoption of higher efficiency technologies and practices in new buildings. The integrated whole-building design incentive will be paid based on the modeled amount of annual electricity savings compared to current building guidelines. Graduated incentives will increase as the whole building becomes more energy efficient. The program will also provide a Design Team incentive that will influence design

professionals to include high efficiency systems and technologies in their whole building design.

Q. WILL YOU PLEASE DESCRIBE THE NON-RESIDENTIAL CUSTOMER REPAYMENT FINANCING PROGRAM?

A. The current Solutions for Business program will be expanded to offer a financing repayment option to schools, municipalities and small businesses to help them overcome the initial cost barriers to implementing energy efficiency. The repayment program will be fully integrated into the Solutions for Business program from the customer's perspective, so that participation will be easy for the customer. APS will manage the program and provide parallel billing to participating customers for ease of repaying the amount financed.

Q. WHAT IS MEANT IN THE SETTLEMENT AGREEMENT BY THE TARGET TO SERVE AT LEAST 100 SCHOOLS?

A. Under the Settlement, APS would serve at least 100 schools through the Solutions for Business program by the end of 2010. In order to meet this target, APS plans to:

- Develop a repayment program for energy efficiency projects, as mentioned above.
- Increase the school program customer cap from $25,000 to $100,000 per district, so larger projects can be funded.
- Work with the Arizona Schools Facilities Board on how the American Recovery and Reinvestment Act ("ARRA") funds for schools ($20 million) can be leveraged with utility rebates.

In addition to these program enhancements, APS will continue to:

- Market the recently approved direct install measures to schools. These measures are aimed primarily at lighting and refrigeration efficiency improvements. The Direct Install measures can pay up to 90% of project costs, making it attractive to many school districts.
- Provide tailored outreach to the Association of School Business Officials ("ASBO"), including targeted training classes and presentations to school districts.

Q. WHAT OTHER PROGRAM MODIFICATIONS ARE CALLED FOR IN THE SETTLEMENT?

A. The Settlement also proposes that large customers should be allowed to self-direct their DSM funds to energy efficiency projects.

Q. WHAT IS SELF-DIRECTION?

A. Self-direction is a term used to describe the ability of a customer or class of customers to reserve a portion of their individual contributions to a system-wide DSM fund for their exclusive use. Those reserved contributions would then be used to fund qualifying projects at the contributing customer's facilities.

Q. HOW WILL THE SELF-DIRECTION PROGRAM OUTLINED IN THE SETTLEMENT WORK?

A. The energy efficiency self-direction program as contemplated in the Settlement would work as follows:

- Customer's service accounts must total in excess of 40 million kWh during a 12-month period, collectively or individually, to be eligible to participate.

- Eligible customers must declare their desire to self-direct their funds prior to the beginning of the calendar year the contribution is made.
- Eligible customers must provide a project application to the Company for review and approval. APS will then verify that the technologies included in the application meet program guidelines and will review the energy efficiency savings claims for reasonableness.
- Funds will be reserved and disbursed annually following completion of the project, until the project is fully funded or the customer's contributions are exhausted.
- APS will be responsible for providing measurement and verification of energy or demand savings after the project is in operation. All kWh energy and kW demand savings will be claimed by APS to meet the Company's energy efficiency goals.

VI. ESTIMATED COST OF ENERGY EFFICIENCY PROGRAMS IN 2010

Q. WHAT DOES APS EXPECT THE COST OF THE ENERGY EFFICIENCY PROGRAMS TO BE IN 2010?

A. As will be described in our 2010 EEIP filing on July 15, 2009, APS estimates the total cost to achieve the energy savings goal in 2010 to be in the range of $40 to $50 million.

Q. HOW WILL THESE PROGRAM COSTS BE RECOVERED?

A. The proposed funding amount will be collected through the DSMAC beginning in March of 2010.

Q. DOES APS EXPECT THE COSTS TO INCREASE FOR 2011 AND 2012?

A. Yes. Based on the need for additional programs in 2011 and 2012 to meet the increasingly aggressive energy savings targets, coupled with the market saturation of some energy efficiency measures, and higher energy efficiency baseline standards, APS expects that the program implementation costs will increase in those years.

Q. WHY ARE THE COSTS OF IMPLEMENTING DSM EXPECTED TO RISE OVER TIME?

A. APS is currently implementing the lowest cost programs and measures to achieve its current energy savings. With higher savings targets, additional programs and measures will need to be introduced into the portfolio that are still cost effective, but that have a higher cost per kWh saved than current programs. The combination of higher savings goals and higher costs per unit saved will drive the future cost of implementing energy efficiency programs higher each succeeding year.

VII. MORE CONCURRENT DSMAC

Q. HOW DOES THE PROPOSED DSMAC DIFFER FROM APS'S CURRENT MECHANISM?

A. An important change in the Settlement's proposed DSMAC from the Company's current mechanism is the movement toward more timely recovery of DSM expenses. The proposed mechanism will allow the company to recover the estimated costs of meeting the energy savings goals closer to the same time those expenses are incurred by utilizing budgeted expenditures to calculate the mechanism change. Today, the adjustor is calculated using only historical expense information. APS witness David Rumolo, who is more familiar with the DSMAC Plan of Administration, will provide detailed mechanics of how the revised DSMAC will operate in practice.

Q. DO OTHER ARIZONA UTILITIES HAVE SIMILAR COST RECOVERY OF DSM/EE COSTS?

A. Yes. In fact, the Settlement's proposed DSMAC is similar to the Commission approved DSM adjustor for Tucson Electric Power Company (Decision No. 70628, December 1, 2008).

Q. HOW DOES TEP'S DSM ADJUSTOR COMPARE TO THE PROPOSED DSMAC FOR APS?

A. Like the TEP adjustor, program costs and performance incentives will begin to be recovered during the year they will be incurred based on estimated costs and then later trued-up to actual costs. Like TEP, APS will earn no interest or other return on under-recoveries but must credit its customers with interest on any over-recoveries. However, the Company's DSM program differs from TEP in that APS will file annually an Implementation Plan that provides detailed information for programs, program costs, and DSMAC rate impacts for Commission review and approval. Also, APS is providing a proposed Plan of Administration for Commission approval as part of this Settlement proceeding. As noted above, the Plan of Administration for the DSMAC is described in Mr. Rumolo's testimony.

Q. WHY IS IT IMPORTANT TO HAVE MORE CONCURRENT RECOVERY?

A. More current DSM cost recovery is desirable for all stakeholders. Matching the timing of expense with the recovery of those expenditures results in customers having a more accurate price signal than a lagging mechanism does. Also, the lag between the incurrence of cost and its recovery is minimized or eliminated, that is, when costs are recovered in the same period in which they are incurred,

it promotes a more favorable cash flow and reduces the costs of financing a lagged recovery.

Q. WILL THERE BE A TRUE-UP EACH YEAR OF ACTUAL EXPENDITURES VERSUS EXPECTED EXPENDITURES?

A. Yes. The total amount of projected expense to be recovered through the DSMAC in any one year will be adjusted by any previous year under or over collection of expenses.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes, APS is committed to the implementation of increased energy efficiency opportunities for its customers. This Settlement Agreement sets a new standard for DSM for the state of Arizona, which will enhance customer benefits for all Arizonans now and further in the future. The energy savings goals will help participating customers save an estimated $1.1 billion on their electric bills over the life of the measures installed in 2010 to 2012. The Settlement Agreement also begins to address the inherent financial challenges that result from enhanced energy efficiency programs. Finally, CO_2 emissions are expected to be reduced by nearly 6 million tons over the life of the measures installed in the next three years. APS believes that the combination of these customer bill savings and emission reductions bring benefits to APS customers and will advance Arizona's sustainable energy future.

Q. DOES THIS CONCLUDE YOUR DIRECT SETTLEMENT TESTIMONY?

A. Yes, it does.

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ARIZONA PUBLIC SERVICE
REVENUE IMPACT FROM SCHEDULE 3 EQUIPMENT ALLOWANCE ALTERNATIVES

PROJECTED NEW CUSTOMERS

	2010	2011	2012
Individual Residential	740	818	1,148
Subdivision Residential	694	767	5,616
Multi-Family	1,573	1,738	2,440
Non-Residential	985	975	1,400

ESTIMATED REVENUE IMPACTS*

	2010	2011	2012
Individual Residential @ $1,000 ea.	$740,000	$810,800	$1,148,000
Subdivision Residential @ $1,000 ea.	$694,000	$767,000	$5,616,000
Multi-Family @$500 ea.	$786,500	$869,000	$1,220,000
Total Residential	$2,220,500	$2,446,800	$7,984,000
Non-Residential @ $4,000 ea.	$3,940,000	$3,900,000	$5,600,000
Total Revenue Impact	$6,160,500	$6,346,800	$13,584,000

* Revenue that would need to be recovered from other sources to maintain the "revenue neutrality" concept as described in the Settlement Agreement.

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ESTIMATED REVENUE IMPACTS @ ESTIMATED COST OF SERVICE ALLOWANCE**

	2010	2011	2012
Individual Residential @ $1,500 ea.	$1,110,000	$1,227,000	$1,722,000
Subdivision Residential @ $1,500 ea.	$1,041,000	$1,150,500	$8,424,000
Multi-Family @ $750 ea.	$1,179,750	$1,303,500	$1,830,000
Total Residential	$3,330,750	$3,681,000	$11,976,000
Non-Residential @ $4,800 ea.	$4,728,000	$4,680,000	$6,720,000
Total Revenue Impact	$8,058,750	$8,361,000	$18,696,000

** Allowance is based on the results of the Cost of Service Study prepared in support of the TY2007 rate case. E.g., for residential customers, the average "wires" investment (allocated distribution rate base less allocated substation rate base) that is supported by rates is approximately $1,470 per customer. An allowance that is established at a level that is approximately equal to the rate base supported by rates is tends to be generous since the revenue from a new customer must support the operations and maintenance of the customer's extension as well as the supporting distribution system. The Cost of Service Study does not allocate costs to multi-family residential customers separately; a 50% allocation was utilized as a simplifying assumption. The non-residential rate base was based on the Cost of Service Study results for E-32 customers on a weighed average basis. For small general service customers (under 20 kW), the allocated rate base is approximately $2,200.

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Using a revenue treatment vs. using a CIAC treatment produces a lower revenue requirement for 2010 - 2012

line		2010	2011	2012
1	**CIAC Treatment Scenario**			
2	**Schedule 3 proceeds recorded as CIAC which reduces ratebase and therefore reduces annual revenue requirements, as follows:**			
3	Schedule 3 proceeds per year	**$ 23**	**$ 25**	**$ 49**
4	Resulting rate base reduction by recording as CIAC (shown net of 40% income tax rate)			
5	2010 vintage	$ (14)	$ (14)	$ (14)
6	2011 vintage		$ (15)	$ (15)
7	2012 vintage			$ (29)
8	Totals	$ (14)	$ (29)	$ (58)
9	Estimated annual fixed charge rate (consisting of depr, property taxes, and pretax return components)	16.9%	16.9%	16.9%
10	**Resulting revenue requirements reductions per year under a CIAC treatment scenario**	**$ (2)**	**$ (5)**	**$ (10)**
11	**Revenue Treatment Scenario**			
12	**Schedule 3 proceeds recorded as revenue which therefore reduces dollar for dollar annual revenue requirements, as follows:**			
13	Schedule 3 proceeds per year	**$ 23**	**$ 25**	**$ 49**
14	Resulting revenue requirements reductions by recording as revenue			
15	2010 vintage	$ (23)	$ -	$ -
16	2011 vintage		$ (25)	$ -
17	2012 vintage			$ (49)
18	**Resulting revenue requirement reductions per year under a revenue treatment scenario**	**$ (23)**	**$ (25)**	**$ (49)**
19	**Comparison:**			
20	**Year by year lower revenue requirements from Revenue treatment vs. CIAC treatment (line 18 vs. line 10)**	**$ (21)**	**$ (20)**	**$ (39)**
21	**Cumulative lower revenue requirements from Revenue treatment vs. CIAC treatment**	**$ (21)**	**$ (41)**	**$ (80)**

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Note 1: Revenue requirements are the revenues needed to cover fuel and purchased power costs, O&M expenses, book depreciation, property taxes, income taxes, and debt and equity financing costs on generation and distribution plant. In a cost of service regulated environment, prices should be set to match these costs. Revenues come from tariffed rates, surcharge mechanisms such as the PSA, or from Schedule 3 proceeds if using a revenue treatment.

Note 2: The estimated annual fixed charge rate consists of a 3.33% annual depreciation expense charge, a 1.50% annual property tax charge and a 12.07% revenue requirement pretax weighted cost of capital from the June 2007 ACC decision 69663.

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ARIZONA PUBLIC SERVICE COMPANY

Estimated Annual Investment in Line Extensions
(Includes Individual Residential, Subdivisions, Non-Residential)

Annual Investment	2005	2006	2007	2008
Individual Residential	$16 million	$20 million	$19 million	$9 million
Subdivisions	$81 million	$95 million	$89 million	$46 million
Multi-Family	$3 million	$4 million	$4 million	$2 million
General Service	$42 million	$48 million	$61 million	$62 million
Total Investment	**$142 million**	**$167 million**	**$173 million**	**$119 million**

Estimated Rate Impact if Current Extension Policy Had Been in Effect in 1990-2007

Reduction in Revenue Requirements*

	Reduction in Revenue Requirements	Impact on Avg. Residential Increase (Monthly)	Impact on Avg. E-32 General Service Increase (Monthly)
Schedule3 Proceeds Booked as Revenue	($173.0) million	($7.43)	($51.62)
Schedule3 Proceeds Booked as CIAC	($139.2) million	($5.96)	($41.35)

*If booked as CIAC, rate base would be reduced by construction cost but a portion of the reduction would be offset by the income tax rate base asset. Analysis based on plant additions 1990-2007.

If booked as revenue, the extension proceeds would reduce the revenue requirements in the test year used to set rates.

The bill impacts demonstrate the reduction in the bill increases under the proposed Settlement Agreement had the current version of Schedule 3 been in place during earlier rate cases.

ACC Jurisdictional OCRB and FVRB With Different Post-Test Year Plant Addition Assumptions
(No Post-Test Year Plant, 6 Months and 12 Months)
(Dollars in 000's)

Line			OCRB		FVRB
	Rate Base without Post-Test Year Plant Additions				
1	Rate Base Per Settlement	$	5,582,135	$	7,665,727
2	Post-Test Year Plant Through 6/30/2009 included in Settlement		473,014		473,014
3	**Rate Base without Post-Test Year Plant Additions**	**$**	**5,109,121**	**$**	**7,192,713**
	Rate Base with 6 Months of Post-Test Year Plant Additions				
4	Rate Base without any Post-Test Year Plant Additions (Line 3)	$	5,109,121	$	7,192,713
5	Post-Test Year Plant Through 6/30/2008		203,234		203,234
6	**Rate Base with 6 Months of Post-Test Year Plant**	**$**	**5,312,355**	**$**	**7,395,947**
	Rate Base with 1 Year of Post-Test Year Plant Additions				
7	Rate Base without any Post-Test Year Plant Additions (Line 3)	$	5,109,121	$	7,192,713
8	Post-Test Year Plant Through 12/31/2008		365,596		365,596
9	**Rate Base with 1 Year of Post-Test Year Plant**	**$**	**5,474,717**	**$**	**7,558,309**

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Monthly Bill
Rate Case Settlement Proposal
Revised August 18, 2009

ARIZONA PUBLIC SERVICE COMPANY
Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 33% of 2009 Carry Forward Costs Recovered in 2010
Revised Projection of 2010 PSA levels to be Reset with Proposed Base Rates

Residential (Average - All Rates)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)		Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	1,177	1,177		1,417	1,417	936	936
Base Rates	$ 116.78	$ 131.66		$ 151.17	$ 170.44	$ 82.38	$ 92.88
PSA- Forward Component	5.98	(1.77)		7.20	(2.13)	4.75	(1.40)
PSA - Historical Component	0.31	(2.94)		0.37	(3.54)	0.24	(2.34)
Interim Rate Adjustor (January 2009)	2.66	-		3.20	-	2.12	-
TCA (July 1, 2008)	1.42	1.42		1.71	1.71	1.13	1.13
CRCC (April 2005)	0.40	0.40		0.48	0.48	0.32	0.32
EIS (July 2007)	0.19	0.19		0.23	0.23	0.15	0.15
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.72	0.72		0.86	0.86	0.57	0.57
Total	$ 131.63	$ 132.85		$ 168.39	$ 171.22	$ 94.83	$ 94.48
Bill Impact (3)		**$ 1.22**			$ 2.83		$ (0.35)
Percent Bill Impact		**0.93%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 1.27	0.96%		$ 1.52		$ 1.01
Increase from Projected 2010 RES (5)		$ 0.24	0.18%		$ 0.24		$ 0.24

Residential (Rate E-12)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	763	763		880	880	645	645
Base Rates	$ 81.71	$ 92.19		$ 102.11	115.21	$ 61.30	69.16
PSA- Forward Component	3.88	(1.15)		4.47	(1.32)	3.28	(0.97)
PSA - Historical Component	0.20	(1.91)		0.23	(2.20)	0.17	(1.61)
Interim Rate Adjustor (January 2009)	1.73	-		1.99	-	1.46	-
TCA (July 1, 2008)	0.92	0.92		1.06	1.06	0.78	0.78
CRCC (April 2005)	0.26	0.26		0.30	0.30	0.22	0.22
EIS (July 2007)	0.12	0.12		0.14	0.14	0.10	0.10
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.46	0.46		0.53	0.53	0.39	0.39
Total	$ 92.45	$ 94.06		$ 114.00	$ 116.89	$ 70.87	$ 71.24
Bill Impact (3)		**$ 1.61**			$ 2.89		$ 0.37
Percent Bill Impact		**1.74%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 0.82	0.89%		$ 0.95		$ 0.69
Increase from Projected 2010 RES (5)		$ 0.24	0.26%		$ 0.24		$ 0.24

EXHIBIT
A-30
ADMITTED

ARIZONA PUBLIC SERVICE COMPANY
Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 33% of 2009 Carry Forward Costs Recovered in 2010
Revised Projection of 2010 PSA levels to be Reset with Proposed Base Rates

Commercial (Rate E-32)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)		Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	8,769	8,769		9,746	9,746	7,792	7,792
Base Rates	$ 781.15	$ 884.44		$ 921.60	$ 1,043.47	$ 640.69	$ 725.41
PSA- Forward Component	44.55	(13.16)		49.51	(14.62)	39.58	(11.69)
PSA - Historical Component	2.26	(21.93)		2.51	(24.37)	2.01	(19.48)
Interim Rate Adjustor (January 2009)	19.82	-		22.03	-	17.61	-
TCA (July 1, 2008)	15.22	15.22		16.91	16.91	13.53	13.53
CRCC (April 2005)	2.96	2.96		3.29	3.29	2.63	2.63
EIS (July 2007)	1.41	1.41		1.56	1.56	1.25	1.25
RES (Jan 1, 2009)	69.60	69.60		77.35	77.35	61.85	61.85
DSMAC (April 2009)	6.52	6.52		7.24	7.24	5.79	5.79
Total	$ 943.49	$ 945.06		$ 1,102.00	$ 1,110.83	$ 784.94	$ 779.29
Bill Impact (3)		**$ 1.57**			$ 8.83		$ (5.65)
Percent Bill Impact		**0.17%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 9.43	1.00%		$ 10.48		$ 8.38
Increase from Projected 2010 RES (5)		$ 5.22	0.55%		5.80		4.64

Industrial (Rate E34/35 Medium Load Factor)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	2,250,284	2,250,284		2,344,877	2,344,877	2,155,690	2,155,690
Base Rates	$ 201,730.50	$ 228,929.00		$ 210,209.00	$ 238,550.00	$ 193,252.00	$ 219,308.00
PSA- Forward Component	11,431.45	(3,375.43)		11,911.98	(3,517.32)	10,950.91	(3,233.54)
PSA - Historical Component	580.58	(5,625.71)		604.98	(5,862.19)	556.17	(5,389.23)
Interim Rate Adjustor (January 2009)	5,085.64	-		5,299.42	-	4,871.86	-
TCA (July 1, 2008)	2,666.44	2,666.44		2,778.52	2,778.52	2,554.35	2,554.35
CRCC (April 2005)	760.60	760.60		792.57	792.57	728.62	728.62
EIS (July 2007)	360.05	360.05		375.18	375.18	344.91	344.91
RES (Jan 1, 2009)	353.78	353.78		353.78	353.78	353.78	353.78
DSMAC (April 2009)	2,106.39	2,106.39		2,194.93	2,194.93	2,017.84	2,017.84
Total	$ 225,075.43	$ 226,175.12		$ 234,520.36	$ 235,665.47	$ 215,630.44	$ 216,684.73
Bill Impact (3)		**$ 1,099.69**			$ 1,145.11		$ 1,054.29
Percent Bill Impact		**0.49%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 3,557.53	1.58%		$ 3,707.07		$ 3,407.98
Increase from Projected 2010 RES (5)		$ 26.48	0.01%		26.48		26.48

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of May 1, 2009.
(2) Bill impacts reflect the proposed increase in base rates, reset of interim adjustor to zero, and reset of PSA to projected Feb 2010 levels to occur commensurate with the new base rates
(3) Bill impacts for commercial and industrial customers are less than residential on a percentage basis because these customer classes were assessed proportionally more for the interim adjustor and the PSA. The base rates reflect approximately the same percentage increase as residential.
(4) DSMAC costs reflect the 2010 implementation plan and the proposed Plan for Administration. 2009 carry forward costs are phased in over three years.
(5) RES impacts are based on the 2010 implementation plan filed in July 2009.
Of the projected increase in the RES budget for 2010, only about $1 to $2 million is attributable to the settlement.

EXHIBIT
APS-31
ADMITTED

DIRECT SETTLEMENT TESTIMONY OF JAMES R. HATFIELD

On Behalf of Arizona Public Service Company

Docket No. E-01345A-08-0172

July 1, 2009

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DIRECT SETTLEMENT TESTIMONY OF JAMES R. HATFIELD ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is James R. Hatfield. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Senior Vice President and Chief Financial Officer of both Arizona Public Service Company ("APS" or "Company") and Pinnacle West Capital Corporation ("Pinnacle West"). I have executive management responsibility for the financial affairs of the Company, including all aspects relating to accounting, finance, taxes, budgeting and financial planning, and investor relations.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I have a Bachelor of Science degree with a functional major in accounting from Central Missouri State University and an M.B.A. degree from the University of Missouri-Kansas City. I have 28 years of experience in the utility and energy business. I joined APS and Pinnacle West in my current capacity in July 2008. Immediately prior to that time, from August 1994 until July 2008, I worked at OGE Energy Corp. ("OGE"), the parent company of Oklahoma Gas and Electric Company. While at OGE, I served in various roles, including Treasurer from August 1994 until January 1996, Vice President and Treasurer from January 1996 until November 1999, and Senior Vice President and Chief Financial Officer from November 1999 until July 2008. Before OGE, I worked in various accounting and finance roles at UtiliCorp United Inc. of Kansas City, Missouri from 1980 through 1994, and served as UtiliCorp's Assistant Treasurer from

1988 to 1993. From January through August of 1994, I also held the position of Vice President, Investor Relations and Corporate Secretary for Aquila Gas Pipeline Corporation of San Antonio, Texas, a publicly traded subsidiary of UtiliCorp United Inc.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will focus on the financial results underpinning the settlement agreement ("Settlement Agreement" or "Agreement") reached by the many parties who participated in settlement discussions in this docket (the "Signatories"). In addition, I will discuss why APS agreed to the provisions in the Settlement Agreement and the considerations that must be made going forward to enable the Company to help implement a proactive energy policy and realize its vision of creating a sustainable energy future for the State of Arizona. The specific terms of the Agreement are discussed in the testimonies of APS Witnesses Jeff Guldner, David Rumolo, Jim Wontor, and Barbara Lockwood.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This case is about the future of energy in Arizona and the investment required not only to maintain safe and reliable service for APS customers but also to provide APS with the necessary means of implementing a sustainable energy policy for the State. APS takes its role in providing for Arizona energy's future quite seriously. Indeed, the Company's business model has at its core a vision of "creating a sustainable energy future for Arizona" – one that brings long-term benefits to the State's environment, economy, and communities.

APS is the largest electric utility in the State of Arizona and, as I will describe, has a statewide presence and influence. As such, APS's financial health is

critical to help the Commission implement a forward-looking, sustainable statewide energy policy. To be "sustainable," however, such a policy must not only support the strategies and business practices that provide the foundation for a healthy environment, vibrant economy, and strong community. It must also allow APS to meet its basic business needs – including the ability to actually earn a reasonable rate of return – while investing in the resources necessary to achieve those important goals.

The Settlement Agreement reached in this case takes a critical step in the right direction. Significantly, it represents the hard work and impressive alignment of the often-disparate interests of the many Signatories – a fact that the financial community understandably views as supportive of Arizona's regulatory environment. The Agreement also buttresses the Company's financial condition in the short term and contains various provisions – including a rate case cycle and rate case process improvements – that can be a starting point for implementing other mechanisms that will reduce the impact of regulatory lag in between rate cases and improve the Company's financial condition in the long run.

But although APS believes that the Settlement is a positive step toward improvement, it still provides no more than the minimal level of rate relief APS needs to support investment grade financial metrics and allow the Company to continue providing reliable electric service at reasonable prices. Even in the short run, before the allowed effective date of rates from APS's next rate case under the proposed rate schedule, the revenue requirement contained in the Agreement allows for only marginal financial metrics. APS will still significantly under-earn its cost of equity capital during this initial period,

projecting ACC-Jurisdictional returns on equity ("ROE") of only 9.4% in 2010, 8.4% in 2011, and 8.1% in 2012 – far below both APS's current authorized ROE of 10.75% and the Agreement's proposed ROE of 11%, and below even the 8.75% return APS investors required on the Company's recent debt issuance (a much less risky investment, for which investors would expect and require a lower return compared to equity investment).

Moreover, although the additional revenue that APS will receive under the Agreement as proposed combined with the required expense reductions is projected to support APS's Funds from Operations to Debt ("FFO to Debt") ratio at current BBB- investment grade levels in 2010 (at 18%), that level is the **very cusp** of the 18% threshold into non-investment grade. There is no margin remaining to hedge the impact of unexpected events that may drive that metric down into junk levels. For the later years, APS projects that its FFO to Debt ratio will fall below that 18% threshold even under the Agreement as proposed, to 17.6% in 2011 and 17.9% 2012.

For purposes of this Settlement, APS accepts the significant challenges presented by these marginal figures, but emphasizes that there is no room for further degradation in the Company's financial metrics without placing the Company at a real and material risk of downgrade. Simply put, it is critical to APS's financial condition, the viability of this Settlement, and a robust energy future for this State that the Company receives the full amount of the increased revenue and other financial supports proposed in the Agreement. To the extent the Commission makes any change to the Agreement's provisions, such change must be revenue- and financially-neutral to the Agreement. In sum, APS envisions a future of working with the Commission to create a sustainable

energy future for Arizona, but currently lacks the resources and tools it needs to do so. APS is not alone in its need for base rate increases – utilities nationwide share that need in their respective efforts to meet the many policy and other challenges facing electric utilities today. What is different regarding APS is the lack of sufficient mechanisms to reduce the impact of regulatory lag and maintain the Company's financial condition in between rate cases. Such tools will allow APS and the Commission to avoid the distraction of a constant string of rate cases, focusing instead on putting in place the important policies that will shape this State's energy future. The Settlement Agreement is a crucial first step toward this important goal.

III. APS'S VISION OF SUSTAINABILITY

Q. PLEASE DESCRIBE THE COMPANY'S VISION OF SUSTAINABILITY.

A. As I previously indicated, APS is committed to working with the Commission and other stakeholders to create a sustainable energy future for the State of Arizona. To APS, this vision means devising and implementing policies and practices that deliberately address environmental stewardship, economic vitality, and community/customer prosperity, and that continually challenge all stakeholders to act now in ways that provide the building blocks for a better future. Importantly, such policies must also provide for a financially healthy APS – one that is able to meet its basic business needs while still investing in the resources necessary to achieve the other elements of what will make Arizona's energy future a truly sustainable one.

Q. HOW CAN APS HELP SHAPE ARIZONA'S FUTURE ENVIRONMENT, ECONOMY AND COMMUNITIES?

A. APS is Arizona's largest and longest serving electric utility, serving Arizona's growing population since 1886. APS serves more than 1.1 million retail and

wholesale customers in all or part of 11 of Arizona's 15 counties – a service territory of approximately 35,000 square miles. With an extensive network of power plants, transmission and distribution lines, offices and support facilities, APS is the largest property taxpayer in the State by a significant margin, infusing $119 million of property tax in 2008 in the vast areas that the Company serves, and more than **doubling** the tax payment of Salt River Project, Arizona's second largest taxpayer.

With 7,200 employees and another 1,152 contractors as of the end of May 2009, APS also generates more jobs than most other Arizona corporations, and is one of the relatively few S&P 500 companies with headquarters here. Together with its employees, APS annually contributes more than $6 million and devotes more than 170,000 hours of volunteer time to literally hundreds of Arizona charitable, cultural, and educational organizations. Last year, the Company purchased from roughly 6,000 suppliers, 170 of which were certified minority- and women-owned businesses. Due to the extensive construction of electric infrastructure necessary to maintain the Company's existing system and meet future demand, APS is also essentially one of Arizona's largest construction companies. In 2008 alone, APS invested approximately $850 million into Arizona's economy as part of its ongoing construction program. This year, that number is projected to reach approximately $880 million, and will likely exceed $20 **billion** through 2025.

Perhaps most fundamentally, APS's product, electricity, is nothing short of vital to economic growth and a functional economy. Customers rely on APS to provide efficient, reliable electric service so that they can live, work, and prosper in their businesses. In sum, APS has a strong presence in the State and

is a key contributor to the State's economy. As such, it is ideally positioned to help shape the economic success and sustainability of Arizona.

Q. HAS THE CHANGE IN THE NATION'S ECONOMY AFFECTED THE COMPANY'S COMMITMENT TO CREATING A SUSTAINABLE ENERGY FUTURE?

A. The degradation in the nation's – indeed, the world's – economy has had devastating impacts on the Company's financial condition. In fact, the downturn in the nation's economy and financial markets has caused revenue erosion and cost increases that have made APS's financial problem significantly worse today than it was when the Company first filed this rate case in June of last year. *See* Attachment JRH-1-S. But the current recession, and its impact on the Company's financial health, has not caused APS to deviate from its commitment to Arizona's energy future. To the contrary, APS believes that this is **precisely** the right time to focus on that vision.

The world of energy is changing: economically, politically, and environmentally. Notwithstanding the current economic slowdown, recent projections show that between now and 2025, APS's customer base will grow by almost 600,000 (rendering a total customer count of close to **1.7 million**). And despite an increasing focus on energy efficiency, the Company's electric sales will grow by over 16 million megawatt-hours ("MWh") – 55% over today's levels – during the same period. In order to continue serving our existing customers and meet this projected demand, APS will have to spend over $15 billion on improvements and additions to its existing infrastructure and billions more for additional generation. Other uncertainties, including the costs associated with potential climate change legislation, compound the challenge of

meeting this demand in the most economically and environmentally sustainable manner.

While navigating these uncertainties presents significant challenges, the process of doing so is also filled with opportunities for APS and the Commission to work together to positively shape Arizona's energy future. By developing policies with a deliberate and continual understanding of how they affect the environment, customers, and the Company collectively, APS will be better positioned to manage the risks and take advantage of the emerging technologies and other innovative energy developments that surely lie ahead.

IV. SETTLEMENT AGREEMENT

Q. TO WHAT EXTENT DOES THE SETTLEMENT AGREEMENT ALLOW APS TO HELP IMPLEMENT A SUSTAINABLE ENERGY FUTURE?

A. APS believes that the Settlement Agreement is a constructive resolution of the case before it and provides important stepping stones toward a regulatory process that will allow the Company and the Commission to create a sustainable future for this State. The Agreement itself represents a salient achievement by the Signatories, each of which worked hard together in a cooperative spirit to begin to resolve the challenges confronting both the Company and other key stakeholders. An important qualitative consideration rating agencies use in establishing credit ratings is the regulatory environment in which the utility operates. The very fact that the Signatories reached a productive agreement in this case displays what the markets view as continued improvement in Arizona's regulatory environment, thus increasing confidence that Pinnacle West and APS are companies worthy of investment.

I could not have put it better than preeminent equity analyst Dan Eggers, who, in reaction to the announcement of the Agreement, upgraded Pinnacle West's rating to "Outperform" from "Neutral" with the following justification: "**We see the PNW story at the cross roads of evolving into an investable story as evidenced by the constructive rate case settlement and recent actions, including forward looking transmission rates, interim rate increase and line connection adder.**" *See* Credit Suisse Upgrade Rating, Pinnacle West Capital Corp., May 26, 2009.

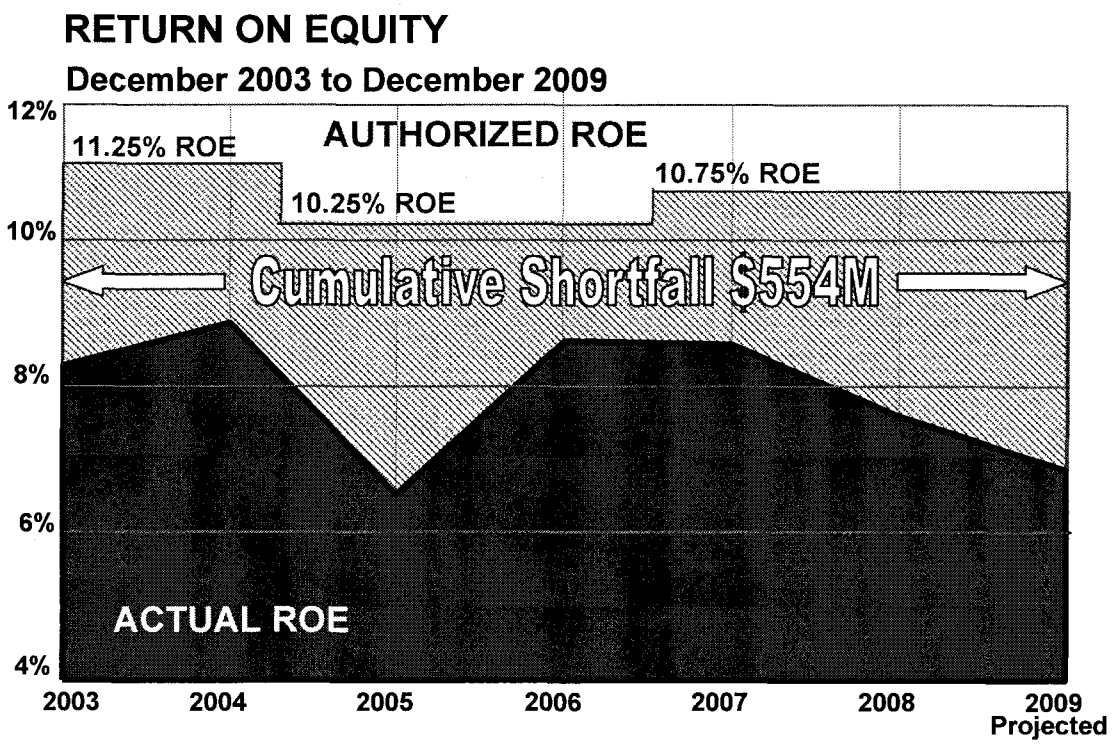
APS believes that it truly is at the "cross roads" of being an "investable" company and that the Settlement Agreement is an important milestone in that direction. In fact, APS firmly believes that the Agreement presents a key opportunity and framework for the Company, the Commission, and other interested parties to explore options that will strengthen the Company's financial condition for the long-term, thus allowing APS to be a critical contributor in creating a sustainable energy future for Arizona.

Q. PLEASE ELABORATE ON THE OPPORTUNITY YOU BELIEVE THAT THIS AGREEMENT PROVIDES.

A. The key opportunity presented by this Agreement is that it provides stakeholders with a framework that can address for the long-term the root of the financial difficulties facing the Company: rates that have not kept pace with the Company's increasing capital expenditures and operating costs. I am firmly convinced that the single largest challenge facing APS is that presented by the use of a historic test year for rate-making in today's cost intensive environment. The historic test year, combined with the ever-changing economic conditions in which the Company operates, has traditionally resulted in rates that are below the cost-levels that APS has faced at that time those rates became effective.

For example, because of the historic test year approach used in APS's last rate case, the Company's current revenues (the prices charged for the electric service that APS provides today) are based on the costs APS incurred in 2005 (the test year used in that case) – **almost half a decade ago**. In other words, even though APS's current costs are, like most people's, much higher today than they were in 2005 for a variety of reasons, the Company is required to pay those higher costs with a revenue stream that is five years outdated. In fact, the Company's current permanent rates do not include $2.5 billion worth of capital expenditure additions.

Insufficient to cover the Company's current cost of service on the date they became effective, such rates could not redress the earnings shortfall APS had historically experienced for the same reason – a shortfall illustrated by the following:

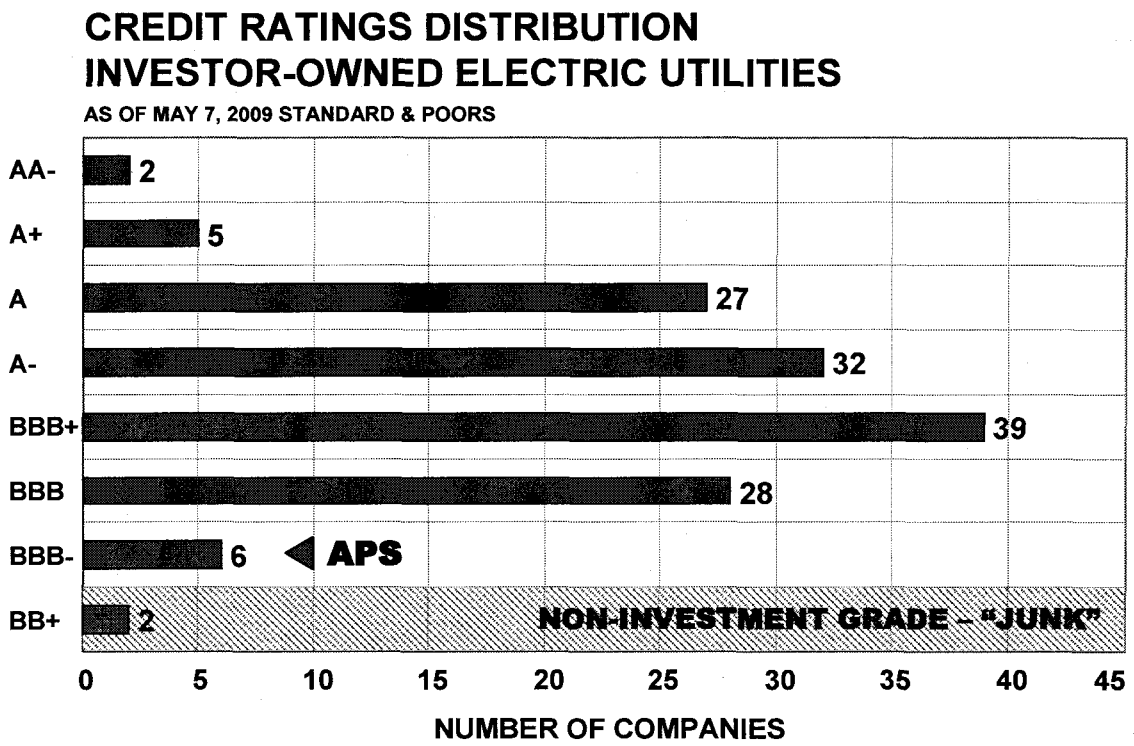


Graph JRH-1

Unless this issue is resolved, this shortfall will only increase and APS will remain in a vulnerable financial position. As a result, the Company will have difficulty raising the capital necessary to serve customers, and will continuously be exposed to potential credit downgrades, thus ultimately impairing both the level and cost of electric service for customers. As one regulatory financial expert succinctly stated, "[m]ore frequent rate filings, deterioration of financial conditions, downgrading of bonds and difficulty in attracting capital are the inevitable consequences of reliance on antiquated historical data." *See* Roger A. Morin, Regulatory Finance, at 4 (1994).

These consequences are a real concern for APS. In fact, as the following demonstrates, APS is still among the lowest rated investor-owned electric

utilities in the country, with credit ratings that are as low as they can be without being rated junk bonds.



Graph JRH-2

This reality hurts not just APS but its customers and all of Arizona, for it jeopardizes APS's ability to secure capital at reasonable costs, thus impacting both the cost and level of investment in Arizona that APS is able to provide. Unless APS has the financial wherewithal to both meet its basic needs and make the requisite investment, the Company simply will be unable to successfully implement the programs and policies intended to benefit the State's energy future.

It comes down to this: what level of service and reliability does the State of Arizona want and what is the price required to support that level of service and

reliability? I believe that the Settlement Agreement sets forth a framework for resolving that question both now and in the future, thus providing a key opportunity for APS to help promote a sustainable energy future for the State.

Q. SPECIFICALLY, HOW DOES THE AGREEMENT PROVIDE THE OPPORTUNITY TO RESOLVE THE CHALLENGE YOU PREVIOUSLY DESCRIBED?

A. The Settlement Agreement provides several building blocks on which stakeholders can work in collaboration to strengthen APS, thus providing significant benefits for all. For example, recognizing the significant capital expenditures that APS has already made beyond the 2007 Test Year and will continue to make before rates in this matter are proposed to take effect in January 2010, the Signatories included in rate base plant additions that the Company has made through June 2009 – 18 months after the Test Year. Although the resulting rates still will not fully compensate the Company for all capital expenditures made up to the proposed rate-effective date (January 2010), this adjustment is nonetheless a notable move in the right direction.

In addition, the Settlement Agreement provides for several procedural refinements intended to expedite future APS rate cases, thus further reducing the revenue-eroding impact of regulatory lag. For example, it requires the Parties to use good faith efforts to process APS rate cases within 12 months of a sufficiency finding, and identifies certain process improvements that will better enable them to do so. The Agreement also establishes a three year rate case cycle for APS, which can and should be used as the starting point for more regular, stable filings over time (to the benefit of all stakeholders in these proceedings), once APS is financially sound. It improves APS's Demand Side Management adjustment mechanism, allowing for more concurrent recovery of

costs related to the Company's energy efficiency programming. It also requires the Company to undergo a benchmarking analysis and report on several operational areas, a provision that the Company views as a tremendous opportunity to put to rest any concerns about the adequacy of APS's operational strength and cost management.

Finally, the Agreement as proposed likely provides for sufficient revenue and related financial relief to maintain the Company's existing financial condition until the time APS is permitted to file another rate case.

Q. DESCRIBE THE IMPACT OF THE SETTLEMENT AGREEMENT ON THE COMPANY'S FINANCIAL CONDITION.

A. While many of the Agreement's provisions can and should be used as building blocks toward designing a regulatory structure that will help the Company improve financially over the long term, the Agreement in and of itself does not get us there. The financial impacts on the Company of the proposed Settlement Agreement are detailed in Attachment JRH-2-S.

As that Exhibit shows, even under the provisions of the Agreement as proposed, APS projects that it will **actually** earn an ACC-Jurisdictional ROE of just 9.4% in 2010, 8.4% in 2011, and 8.1% in 2012. These earnings are significantly below not only the Settlement's proposed ROE of 11% and the ROE recommended by any other party to these proceedings, but are also below the actual earned ROE of the industry peers against whom APS competes for invested capital (a point I will later discuss in detail).

In short, the ROE that actually results from the revenue requirement to which the Company agreed is significantly less than what it needs to earn to invest in this State's energy future. There is simply no room for further degradation in

the Company's financial metrics – a fact that highlights how critical it is both that (1) the rate schedule set by the Signatories in the Agreement is not extended, thus permitting APS to seek a rate increase that would be effective in 2012; and (2) APS receives, in some form or another, the full amount of the revenue requirement and other financial measures proposed by the Signatories (including the revenue treatment of Schedule 3, deferral of pension and OPEB costs, and the depreciation rate update relating to the Palo Verde license extension). In other words, to the extent the Commission decides to change any of the Agreement's provisions, such change must be revenue- and financially-neutral for the outcome to remain a viable one for APS.

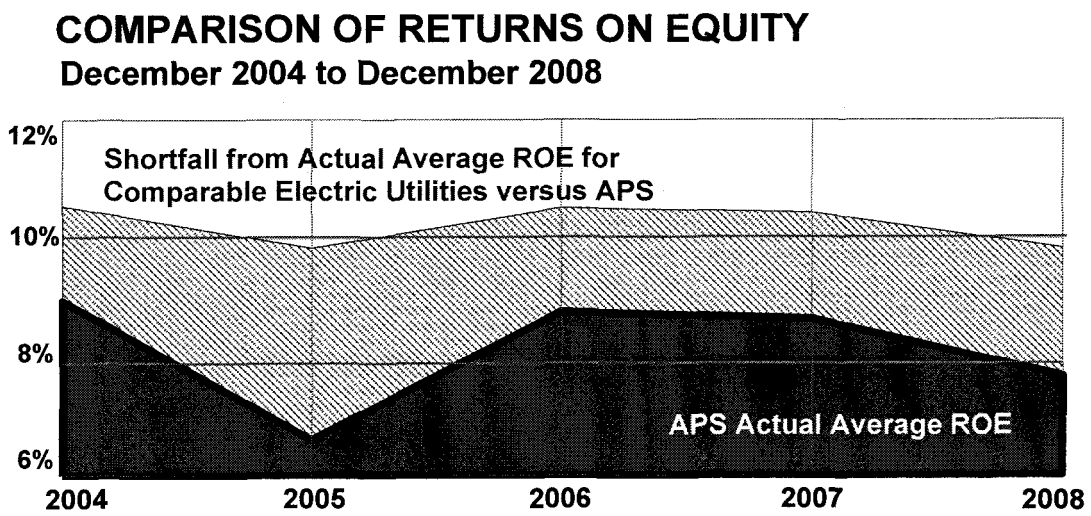
Q. WHY IS THE COMPANY'S ACTUAL RETURN ON EQUITY IMPORTANT?

A. In every APS rate case, the Commission sets the Company's recoverable cost of capital – both for debt and equity – based on what it believes investors in the Company should reasonably expect to receive, not hypothetically, but in reality when the new rates are in effect. In Decision No. 69663, the Commission authorized APS to receive a 10.75% ROE. In other words, the Commission determined that it was reasonable that APS's rates should generate enough revenue to both cover the Company's operating expenses and give APS and its shareholders a 10.75% return on their investment (the Company's "earnings"). In the proposed Settlement Agreement, given the increased risk investors assume by investing in the Company's equity in the current market, the Signatories have agreed that an 11% ROE is a reasonable one. This cost of capital was originally proposed in and is amply supported by the Testimony of Staff Witness David Parcell.

But investors looking to purchase equity in the Company do not look primarily at the Company's **authorized** ROE. Rather, before deciding whether to put their money into APS as opposed to any of the other companies against which APS competes for capital investment – including other investor owned utilities – they look at the **actual** return that they are likely to receive: APS's **earned** ROE. Unless APS has the actual and real opportunity to earn its authorized rate of return (which I understand is a right grounded in the Constitution), the ROE set by the Commission is little more than a number to potential investors.

By that standard, APS's financial performance falls well below the mark. Indeed, the Company's current returns provide little incentive for investors to put their money into APS compared to the portfolio of less risky opportunities available elsewhere in the electric industry. For investors, investment decisions are not personal, but are rationally based on what amounts to a clinical analysis of which investments are likely to bring the highest returns. As the following illustration shows, APS does not compare favorably next to other comparable[1] companies in the industry whose earned returns are significantly higher.

[1] The companies used in this comparison are those that, like APS, are electric only, publicly-owned operating companies that have more than 100,000 customers and own at least 20% of their base load generation. These are the companies against which APS competes for equity investment.



Graph JRH-3

As the foregoing demonstrates, APS fights an uphill battle trying to attract equity investment with such comparably low returns.

Neither will existing equity investors in APS willingly allow their investment to systematically underperform. By this, I mean that current investors will not accept less than the cost of capital just because APS needs that capital or because the economy is bad. This is particularly true when the Company's actual earned returns are below the rate at which APS just issued **debt** (at 8.75 percent). So if APS's cost of equity capital is 11 percent as proposed in the Settlement Agreement, or 10.75 percent as found in Decision No. 69663, any earned return significantly less than that does not meet the market's requirement for attracting new equity on reasonable terms or provide any incentive for current equity investors to retain their investment in APS any longer than is necessary to liquidate it.

Without capital investors, APS will have lost an essential source of funding for its significant capital projects – projects needed not just to meet future demand,

but to maintain APS's existing electric system and provide the foundation for a more sustainable future for this State. Even if APS were to be able to issue equity with such low returns, such issuances would certainly be made under onerous terms (requiring striking discounts to the Pinnacle West's stock price per share), thus substantially driving up the cost of APS's capital program – an end that ultimately translates into higher electric rates for customers.

Maintaining the status quo is thus, in the long run, a lose-lose proposition for both the Company and the many stakeholders to this proceeding. Conversely, companies with higher levels of earnings are able to attract both debt and equity investment on better terms, thus **lowering** the ultimate cost to customers. Higher revenue streams from rates that cover the Company's cost of service also allow APS to reduce to a degree otherwise required debt and equity issuances, thus keeping the cost of capital borne by customers to the necessary minimum.

In the end, improving the Company's earnings – even if difficult in the short term – will keep the price of electric service down and ensure that APS has the capital it needs to continue to invest in the energy future of this State. This is the win-win scenario toward which I believe all stakeholders should collectively strive.

Q. WHY SHOULD CHRONIC APS UNDEREARNING BE A CONCERN TO THE COMMISSION AND APS CUSTOMERS WHEN APS IS STILL MAKING A PROFIT?

A. All stakeholders in these proceedings should be concerned about resolving the Company's chronic underearning because, without substantial improvements to APS's financial health (particularly in today's troubled economy), the Company will be unable to provide reliable electric rates at reasonable prices while working towards a sustainable energy future for Arizona.

To continue its long history of service reliability, APS simply must recover on a regular basis its cost of providing service. More than a basic legal and regulatory requirement, it is also a practical economic necessity. Examples exist throughout the industry of utilities forced to cut back on services in one way or another to compensate for a revenue stream that did not allow a sufficient return to attract the capital that the utility needed to continue to serve customers in the manner to which they were accustomed. Neither APS nor, I believe, its customers, this Commission, or anyone else wants the Company to be in a position where it is forced to cut back on service so that it can cover its basic costs, including the cost of capital.

In addition, in setting rates below the Company's costs, the Commission sends the wrong price signals to customers who will not know – because they do not pay – the real cost of electricity. In an era of energy conservation, it makes little sense to set the price of this essential commodity **too low**. To reduce vehicle emissions one would not **decrease** the price of gas; doing so would send the entirely wrong message. To encourage energy efficiency, among other things, customers should know and be required to pay the real cost of electricity, not a subsidized one.

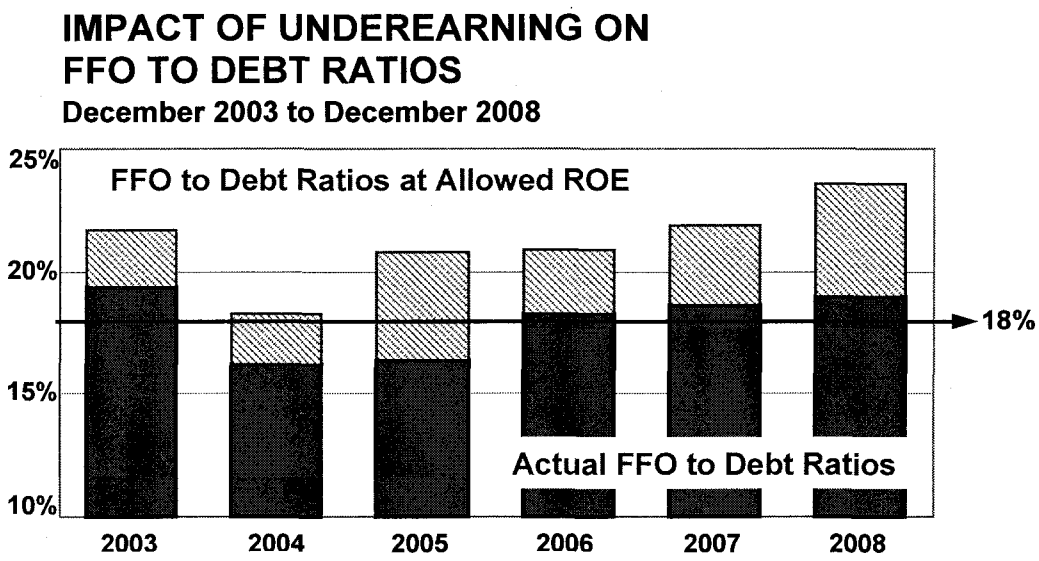
Q. IN THE PAST, APS HAS EXTENSIVELY DISCUSSED THE FFO/DEBT RATIO. SHOULD THAT METRIC ALWAYS BE THE FOCAL POINT IN ASSESSING THE COMPANY'S FINANCIAL CONDITION?

A. Although FFO/Debt was the proper focus in the Company's past emergency rate proceedings, since the alternative was non-investment grade, that metric should not be the single focal point for assessing APS's financial health. As the Commission knows, APS is an investor-owned utility to which three primary credit rating agencies assign a credit rating. Capital markets use that rating to

determine whether or not the Company is worth investing in at all, and, if so, at what cost. Simply put, the worse the Company's credit rating, the higher its financing costs (costs that are ultimately borne by customers). The consequences of having a low credit rating are particularly difficult in the current, still volatile credit markets, where access to the market is often blocked to subpar performers and financing costs are at a premium.

In each of the Company's past emergency rate cases, APS believed that it was on the brink of downgrade – in large part because its FFO/Debt ratio had fallen or was projected shortly to fall below the 18% FFO/Debt threshold level set by S&P for the Company's current credit rating (BBB-, the lowest rating possible before falling into "junk" status). While the FFO/Debt metric is a crucial consideration in emergency cases when APS believes that a downgrade is imminent, it should not be the long-term focal point in assessing the Company's financial health overall. Revenue increases based solely on keeping FFO/Debt at or above that 18% threshold will **never** improve the Company's financial condition because they ignore the root of the Company's financial problem: insufficient equity returns.

If APS and the Commission focused on fashioning rate relief that gave APS the real opportunity to earn its ROE (rather than maintaining minimally acceptable FFO/Debt levels), **all** of the Company's credit metrics would improve because APS would have sufficient revenue to meet its basic expenses and offset debt. As the following illustration shows, had APS earned its allowed ROE since 2003, its FFO/Debt ratio would never have been an issue.



Graph JRH-4

The foregoing demonstrates that had rates been at the level required for the Company to earn its allowed returns since just 2003, FFO/Debt would not be teetering continually on the edge of junk status, and the Company would be less reliant on tumultuous capital markets. As a result, the Company's need for constant rate filings to protect against a credit downgrade would have been alleviated. With greater revenues, investors would be much more inclined to put money into the Company, APS's credit rating would almost certainly elevate (thus **lowering** APS's financing costs and the rates ultimately charged to customers), and APS would have the financial means needed to invest in the sustainable energy future envisioned for Arizona.

Q. IF APS BELIEVES THAT THE SETTLEMENT RESULTS IN SUCH MARGINAL RETURNS ON EQUITY, WHY DID APS AGREE TO IT?

A. APS agreed to this Settlement for several reasons. First, it appreciated the Signatories' clear and cooperative attempt to fashion an Agreement that addresses the significant challenges that APS and all stakeholders face today,

even if only for a few years. Second, the Company recognized that, because economic and financial conditions had deteriorated from when it first filed this rate case in June of 2008, its original asking was inadequate compared to its current revenue needs and – even if granted in full – would not have restored APS to financial health. Third, and most significantly, APS firmly believes that the opportunities set forth in this Agreement for a long-term solution outweigh the shorter term financial struggles the Company will face in the next few years.

Q. ONE MIGHT ASK WHETHER INADEQUATE COST MANAGEMENT IS THE SOURCE OF THE COMPANY'S FINANCIAL PROBLEMS. HOW DO YOU RESPOND?

A. There is no doubt in my mind that the reason for APS's poor earnings is insufficient revenues as opposed to excessive costs. Since joining APS and Pinnacle West in July 2008, I have witnessed first-hand the Company's commitment to cutting costs, deferring non-critical expenditures, and otherwise managing its finances in a way that helps relieve the short-term financial pressures without jeopardizing service reliability. From an operational perspective, the Company demonstrates top-quartile performance in fossil generation, reliability, and customer service. In terms of managing costs, the Company has, among other things and after extensive operational analysis, eliminated jobs, imposed a hiring freeze, increased insurance retentions, cancelled merit increases for Officers and Senior Management, reduced merit increases for other non-union workers, and reduced working capital requirements. These measures are thoroughly outlined in a letter from APS President Don Robinson to the Commission, filed on March 18, 2009, attached hereto in Attachment JRH-3-S. And in this Settlement, APS has committed to further annual expense reductions for the term of the Agreement.

But cost-cutting alone cannot significantly improve the Company's financial condition. APS simply cannot cut enough expenses to earn its authorized rate of return without significantly sacrificing reliability and quality of service. Despite APS's cost-management efforts and the additional revenue resulting from the interim rate proceeding, APS **still** has an annual revenue requirement deficiency of $260 million for 2010 – $80 million more than will be recovered under the terms of this Agreement. To address this deficiency solely on the cost side rather than the revenue side would mean eliminating projects or services that are nothing short of vital to APS's basic service obligations, such as repairing and replacing older or damaged distribution facilities and serving our growing customer base. APS certainly would not willingly resort to sacrificing reliability in order to improve its financial condition, and highly doubts that its customers or the Commission would want it to either.

Regardless of the outcome of this proceeding, I guarantee that the Company will continue to explore ways to improve its financial performance internally through sound business judgment and management choices at all levels of the Company's operations. However, as a relative newcomer to the Company with substantial experience in the utility industry, I would like to emphasize two key points: (1) it is my opinion that this is a very well-managed company; and (2) cost cutting alone cannot significantly improve the key financial metrics. That will only happen by addressing the chronic underearning suffered by the Company.

Q. HOW DO YOU RESPOND TO THE SUGGESTION THAT THE COMPANY'S CONTINUAL EARNINGS SHORTFALLS SHOULD HAVE BEEN ALLEVIATED BY THE IMPLEMENTATION OF THE POWER SUPPLY ADJUSTOR, TRANSMISSION COST ADJUSTOR, ETC.?

A. While the Company certainly appreciates the mechanisms the Commission has put in place since 2003 to deal with unrecovered costs and bolster the Company's cash flow, these mechanisms have not materially improved and cannot improve the Company's earnings because they merely facilitate the recovery of previously incurred costs. Significantly, of the Company's total revenue increases since 2003, the amount that has gone to cover the striking growth in rate base investment and non-fuel O&M costs that APS has experienced over the past six years would constitute just over a four percent rate increase – and more than half of that resulted from the interim increase authorized in this docket, which is included in the overall increase proposed by this Agreement. The overwhelming majority of the Company's recent rate increases, recovered through such mechanisms as the PSA, recovers fuel and other expenses that are a mere pass-through of costs for the Company, which do not improve APS earnings. The key piece of the puzzle is to address the earnings shortfall resulting from historically large capital expenditures coupled with regulatory lag so that the Company can begin to earn its cost of capital, a critical element for the Company to regain its financial health and support a sustainable energy future for Arizona.

Q. SHOULD APS ACCEPT LOWER RETURNS GIVEN HOW THE GENERAL DOWNTURN IN THE ECONOMY HAS AFFECTED INDIVIDUALS AND OTHER COMPANIES?

A. APS certainly recognizes the effect that the current economic downturn is having on its customers and other individuals and companies throughout Arizona and the United States. The Signatories, in fact, attempted to minimize

the impact of the proposed rate increase by including a provision in the Agreement that accelerates the refund that may be owed customers under the PSA, which could result in a net increase to base rates of less than 5%. And while an increase in the price of electricity may be more difficult for customers to absorb in hard economic times, the Commission should be aware that APS rates have increased substantially less than the rate of inflation in this decade, and that, even under the provisions of the Agreement, electricity is a smaller percentage of personal income than it was ten years or more ago.

Moreover, unlike other businesses facing a financial crisis, APS has an obligation to continue to provide electric service to all present and future customers, even in hard economic times. As a regulated utility under a "cost of service" regulation model, APS is not permitted to increase its profit margins by increasing electric rates in good times. This ensures that electricity – a basic need of the modern world – remains as affordable as possible, based only on the cost to APS of providing service. On the flip side, recognizing that cost of capital is a basic cost of providing electric service and that adequate earnings are necessary to attract the capital needed to continue serving the public reliably and affordably, the cost-of-service model is also designed to give the Company the opportunity to earn its authorized profit margin even when times are tough and the economy has slowed. Doing so will ensure continued investment in Arizona's electric utilities, the continued provision of reliable electric service at reasonable costs, and the creation of a sustainable energy future.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS strives towards a future of working with the Commission to create a sustainable energy future for Arizona, but currently lacks the financial wherewithal necessary to do so. Utilities across the country, faced with many of the same challenges confronting APS, share the Company's need for base rate increases. Many states have already adopted mechanisms to reduce regulatory lag and that result in rates that recover a utility's cost of service. Other states are now in the process of adopting and implementing new regulatory mechanisms with the same goal. For APS, the Settlement Agreement is similarly a critical step towards reducing the impact of regulatory lag and providing rates that cover the Company's actual cost of service at the time they become effective. Only with such progress will the Company's financial condition improve, thus allowing the Commission and APS to focus on putting in place the important policies that will help shape this State's energy future. With this in mind, APS urges that the Commission approve the Settlement Agreement.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Major Items Causing the Deterioration of Projected 2010 ACC Financial Results from June 2008 Rate Request to the Settlement Proposal

$ in Millions

Line		Earnings After Income Taxes	Average Common Equity	ACC ROE
1	Projected 2010 ACC results under the Company's June 2008 rate request	$ 362	$ 3,339	10.8%
2	Reduced non-fuel base rate increase $68m from $264.3m to $196.3m (10.0% to 7.4%) through settlement negotiations (measured on 2007 test year)	(41)		
3	Reduced revenues after related fuel and purchased power savings of $55m from lower projected sales growth due to the economic downturn and energy efficiency programs	(33)		
4	Higher pension and opeb costs of $14m due to financial market conditions	(8)		
5	Higher interest costs of $10m on February 2009 $500m long-term debt issuance due to financial market conditions	(6)		
6	Low income bill assistance funding of $5m in 2010 agreed to through settlement negotiations	(3)		
7	Assumed cost reductions of $28m ACC share	17		
8	Other changes	3		
9	Total change in projected 2010 ACC earnings	(71)		
10	Projected 2010 ACC results under the proposed settlement agreement	$ 291	$ 3,087	9.4%

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED INCOME STATEMENTS
WITH PROPOSED SETTLEMENT RATE INCREASE
(Dollars in Thousands)

Line No.	Description	Projected Year - Total Company			Projected Year - ACC Jurisdiction		
		Year Ending 12/31/2010	Year Ending 12/31/2011	Year Ending 12/31/2012	Year Ending 12/31/2010	Year Ending 12/31/2011	Year Ending 12/31/2012
1.	Electric Operating Revenues	$3,404,430	$3,445,936	$3,586,487	$3,301,488	$3,344,423	$3,481,929
2.	Fuel and Purchased Power	1,247,359	1,241,234	1,313,613	1,347,016	1,367,368	1,454,166
3.	Operating Revenues Less Fuel Expenses	2,157,071	2,204,702	2,272,874	1,954,472	1,977,055	2,027,763
	Other Operating Expenses:						
4.	Oper and Maint excluding fuel expense*	888,854	930,026	956,765	840,096	878,705	903,335
5.	Depreciation and Amortization	417,205	438,429	431,862	369,351	387,114	378,085
6.	Income Taxes	196,592	187,462	192,989	175,890	160,782	163,876
7.	Other Taxes	139,810	140,902	148,853	120,877	121,830	128,705
8.	Operating Income	514,610	507,883	542,405	448,258	428,624	453,762
	Operating Income (Deductions):						
9.	Income Taxes	6,010	5,039	6,159	1,908	253	116
10.	Allowance for equity funds used during construction	27,819	28,407	32,757	18,900	20,100	21,255
11.	Other Income	1,117	769	1,215	(104)	(682)	(313)
12.	Other Expenses	(17,385)	(14,476)	(18,083)	(5,000)	-	-
13.	Total	17,561	19,739	22,048	15,704	19,671	21,058
14.	Income Before Interest Deductions	532,171	527,622	564,453	463,962	448,295	474,820
	Interest Deductions:						
15.	Interest on long-term debt	207,244	210,426	240,381	169,747	170,543	193,231
16.	Interest on short-term borrowings	11,337	15,609	14,777	9,286	12,651	11,879
17.	Debt discount, premium and expense	4,991	4,903	4,100	4,991	4,903	4,100
18.	Allowance for borrowed funds used during construction	(16,720)	(17,093)	(19,700)	(11,392)	(12,086)	(12,796)
19.	Total	206,852	213,845	239,558	172,632	176,011	196,414
20.	Net Income	$ 325,319	$ 313,777	$ 324,895	$ 291,330	$ 272,284	$ 278,406
21.	% Return on Average Common Equity	8.6%	7.8%	7.6%	9.4%	8.4%	8.1%
22.	Average Common Equity	3,773,157	4,006,397	4,249,416	3,087,229	3,248,686	3,417,963

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs

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A subsidiary of Pinnacle West Capital Corporation

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Director Utilities

March 18, 2009

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007-2996

Re: Compliance Filing of Arizona Public Service Company Regarding Cost Management Efforts, Docket No. E-01345A-08-0172 (Interim Rate Proceeding)

Dear Sir or Madam:

In Decision No. 70667 (December 24, 2008), the Commission directed Arizona Public Service Company ("APS" or "Company") to examine its operations and expenses and employ "easily identifiable short term measures" to improve its financial condition. That decision indicated that APS should target additional cost reductions to operations and expenses of at least $20 million. The specific reductions to be included in this effort were left to APS's discretion, but the decision directed APS to consider such items as (1) reducing lobbying expenses, (2) reducing advertising expenses, (3) paring back management compensation for 2009, (4) imposing a temporary hiring freeze for all non-essential personnel, (5) examining payroll overhead, and (6) implementing a freeze on any increases in its dividend in 2009.

APS has identified and is in the process of implementing a minimum of $25.9 million of specific cost reductions to operations and other costs for 2009, which are described below and summarized on the attached Table 1. These cost reductions are in addition to the substantial cost management savings that have previously been discussed with the Commission. (*See* October 14, 2008 and November 26, 2008 letters, both of which are attached.) Further, APS is committing to several of the specific actions identified in Decision No. 70667, including a dividend freeze and a hiring freeze for non-essential personnel for the remainder of 2009.

In identifying and pursuing these additional cost reductions, APS has sought to carefully balance the benefit of attaining short-term improvements in the financial condition of the Company with the risk of resultant long-term adverse consequences to our customers and the Company—certainly a challenge that many businesses are faced with in today's economy. The actions APS is taking with respect to each such specific

cost reduction area identified in the decision is discussed below, followed by a discussion of other cost management actions APS is implementing, concluding with an update on the overall cost management efforts of the Company.

I. Specific Areas Referenced in Decision No. 70667

Lobbying Expenses. APS's 2009 lobbying budget, for both state and federal lobbying, has been reduced by $500,000. This represents nearly a 20% reduction to the total budget, even though current state and federal legislative activity is higher, more complex and more important than at any time in recent memory. Much of this savings will be achieved from the cancellation or non-renewal of outside services agreements.

Advertising Expenses. APS currently receives specific funding for customer outreach and program marketing relating to RES and DSM activities from surcharges, which will remain at current Commission-approved levels. However, APS has reduced its remaining non-funded advertising budget by approximately 30% or $1,000,000. This non-funded advertising budget had supplemented RES and DSM advertising programs, largely in the area of developing and producing new advertisements and messages focused on renewable energy, energy efficiency and safety. Nevertheless, APS believed it appropriate to make these reductions. The remaining APS advertising budget will continue to emphasize renewable energy, energy efficiency, customer programs and safety.

Management and Other Compensation. APS had incorporated a higher base salary amount in its 2009 budget. This was not a cost of living adjustment, but instead reflected APS's long-standing practice of granting annual merit increases based on both individual performance and labor market trends. The Company determined, however, to freeze all officer and senior managers salaries at levels established in late 2007, and to freeze all other management salaries at 2008 levels.[1] In addition, merit increases for non-union[2] frontline employees were significantly reduced or eliminated. The APS share of total savings resulting from this action was $7.5 million. APS also has frozen contractor wage increases for 2009. APS estimates its share of those savings to be an additional $1.8 million.

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[1] An employee who receives a promotion, however, could move into a higher grade.

[2] APS's current collective bargaining agreements contractually specify how annual union base pay increases are to be implemented and could not be modified.

Temporary Hiring Freeze. APS requires CEO approval to fill any new position or any vacant position with an outside hire, and such approval will be provided for only the most critical positions.

Payroll Overhead. The Company has modified its medical plan program to reduce the medical costs absorbed by APS, primarily by increasing co-pays and limiting the scope of certain benefits. Total APS savings from this change will be approximately $1.2 million.

Dividend Freeze. APS will not increase its dividend in 2009.

II. Other Cost Savings Identified by APS

In addition to the areas described above, APS has identified cost savings in other areas:

Fossil Generation O&M. APS will reduce fossil plant O&M by reducing or deferring work on various maintenance items in 2009, including deferring certain maintenance work at the Four Corners, West Phoenix, Cholla, and Redhawk power plants. APS share of these savings will be approximately $4.1 million.

Other O&M Reductions. APS will also reduce or postpone various activities in legal, customer service, information services, delivery, finance and facilities. For example, APS will further consolidate and streamline its call center functions, reduce the level of internal mail service at various Company locations, and reduce insurance limits. APS savings from these reductions will be approximately $4.0 million.

Supply Chain Cost Reductions. APS is implementing a new supply chain management sourcing effort that will reduce the price paid for wood, steel and concrete poles and towers. Estimated annual savings are approximately $1.5 million.

Freight and Delivery Cost Reductions. APS is implementing a new company-wide initiative to reduce freight costs and optimizing material delivery costs that will result in an annual savings of approximately $1.3 million.

Renegotiated Call Center Contract. APS has renegotiated a contract for APS Call Center contract labor resulting in annual savings of approximately $500,000.

Lowering Technology Services Support. Technology services support related to responsiveness and availability for APS departments will be reduced. APS savings will be approximately $1 million.

Reduction of Short Term Interest Expense. APS will reduce working capital in an amount that would result in an annual reduction of short term interest expense by at least $1.5 million.

APS believes that the estimates of cost savings identified above are conservative. These cost savings do not reflect any estimate of potential vacancy savings in 2009 from the more restrictive hiring freeze. Neither does it include additional interest, depreciation, and property tax savings from reduced capital expenditures. In that regard, and in addition to those cost reductions previous announced, APS recently eliminated another $72 million from its 2009-2011 capital budget.

III. APS's Overall Cost Management Efforts

APS has approached these additional cost reductions similarly to the cost reductions announced last year—with a critical and often difficult balancing of short-term and long-term impacts to our customers, employees and operations. The challenges facing both our industry and our state are significant, further complicating this balancing process. APS remains committed to maintaining reliability and customer service, while efficiently and proactively planning for the future in these most uncertain of times. For example, the Resource Plan Report submitted to the Commission earlier this year is a key element of the Company's long-term planning.

High-quality customer service, reliability, prudent long-term planning, resource diversity, operational excellence—all the things that go into sustainability—require APS to be financially strong so that it can attract and retain the resources, both capital and human, necessary to fulfill its obligations to the public and its over one million Arizona customers. As APS has indicated in its pending rate case, long-term improvement in the financial health of the Company cannot be achieved solely through more aggressive cost management, but must be complemented with prices that truly reflect APS's prudent and reasonable cost of providing service. At the same time, APS recognizes that it has the responsibility to actively and effectively manage those costs without compromising service and reliability and without sacrificing long-term efficiencies for short-term benefit.

IV. Conclusion

The Company is committed to cost management in both good times and bad. But the current economic circumstances for APS and its customers make those efforts doubly important. APS does not intend to stop its cost containment efforts with just the actions identified above but will rather continue to build on them throughout this year and into

future years. In all such efforts, the focus will remain on APS's core values of safety, reliability, customer service, and value for customers.

Sincerely,

Donald G. Robinson

cc: Chairman Mayes
Commissioner Pierce
Commissioner Newman
Commissioner Kennedy
Commissioner Stump
Michael Kearns
Ernest Johnson
Terri Ford
Barbara Keene
Janice Alward
Brian Bozzo
Parties of Record

Table 1: Summary of Cost Reductions

Area	Action Being Taken	Cost Savings
Lobbying Expenses	Reducing expenditures, including reduced consulting arrangements	$500,000
Advertising	Reducing expenditures primarily related to design and production	$1,000,000
Management and Employee Compensation	Freezing base compensation for all management employees and many non-union frontline employees	$7,500,000
Contractor Wage Freeze	Freezing wage or salary increases for contractors	$1,800,000
Reduced Payroll Overhead	Modifying medical plan to require higher co-pays and limit certain benefits coverage	$1,200,000
Fossil Plant	Deferring or reducing various maintenance items for 2009	$4,100,000
Legal, Customer Service, Information Services, Delivery, Finance and Facilities	Deferring or eliminating various activities and support functions in each of these areas, such as consolidating and streamlining call center functions, reducing internal mail service, and modifying insurance coverages	$4,000,000
Supply Chain Management	Reducing cost of acquiring wood, steel, and concrete poles	$1,500,000
Freight Delivery	Reducing and optimizing freight and delivery costs	$1,300,000
Call Center	Reduce contract labor costs	$500,000
Technology Services	Reduce level of technology support for various business units	$1,000,000
Short-Term Interest	Reduce level of required working capital resulting in interest savings	$1,500,000
Total		***$25,900,000***

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This 18th day of March 2009 to:

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PINNACLE WEST
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LAW DEPARTMENT

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October 14, 2008

Hon. Lyn Farmer
Chief Administrative Law Judge
Hearing Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Re: Docket No. E-01345A-08-0172 (APS Interim Rate Request)
APS Late-Filed Exhibit 23

Dear Judge Farmer:

As stated in my letter to you dated September 26, 2008, this is the second part of Arizona Public Service Company's ("APS" or "Company") response to the outstanding requests for certain information in the above proceeding. Per your instructions, this letter and its attachments have been designated as APS Exhibit 23.

Attachment 1 to this letter provides a more detailed breakdown of reduction in the anticipated capital expenditures ("CAPX") for the years 2009-2011. It does so by first beginning with the CAPX forecast presented in Exhibit DEB-3, which is an attachment to Donald E. Brandt's Direct Testimony in the pending general rate case, but with 2011 added using the same assumptions that had been used for the years 2009 and 2010 in Exhibit DEB-3.[1] The net changes to the CAPX forecast as of October 2008 are set forth separately. As you can see, anticipated CAPX reductions in distribution, transmission and general plant actually exceed $500 million[2] APS has provided the CAPX forecast changes in the same format and to the same level of granularity as in Exhibit DEB-3 for ease of

[1] The rate case testimony attachment had not addressed 2011 because it was 2010 that formed the basis for the Company's proposed attrition adjustment. However, to start everyone off on the same page with an "apples to apples" comparison; APS added what would have been the 2011 forecast using the same assumptions as for 2009 and 2010 in DEB-3.

[2] As the Commission is aware, Palo Verde is operating under a separate Performance Improvement Plan and is not included in the general Company efficiency/cost reduction program that will produce the reduction in future CAPX. Therefore, and although Palo Verde CAPX may change for reasons unrelated to the more general CAPX reduction program, it is held constant at DEB-3 levels for purposes of this analysis.

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comparison. This means, for example, that while the major transmission projects that will be delayed are specifically identified to the extent they were in the prior CAPX forecast, smaller projects (and even larger projects that were not included in the earlier 2008 DEB-3 forecast) are shown collectively at line 22. Please also note that these represent preliminary estimates that may change materially, either up or down, depending on future events and more specifically, depending on the needs of our customers.

Although not specifically requested, APS believes there was some confusion during the recent hearing over the CAPX forecast submitted in August of 2007 and that subsequent CAPX forecast attached to Mr. Brandt's general rate case testimony. *See* Brandt Testimony at 602:7 – 603:10. A great deal, if not all, of the differences between the two forecasts is a result of the differing vintages of the forecasts. Although provided in August of 2007, what was then requested was a breakdown of the capital items identified back in late 2006 as Exhibit 27 in the Company's last general rate case. As can be seen on Attachment 2, the actual vintage of the forecast that resulted in both Exhibit 27 and the August 2007 filing was August of 2006 – some 21 or 22 months earlier than the forecast used for DEB-3 (rather than the six or seven months referenced at the time of the hearing) and well prior to the Company's announcement of $200 million CAPX reductions in late 2007 and early 2008 (which, of course, have recently been significantly expanded). Attachment 2 provides a reconciliation between the two vintages of CAPX forecast. APS would add that although the actual time between the two forecasts is considerably longer than what may have been thought during the recent interim rate hearing, even if there had been "only" a six month difference, it is still very possible that a CAPX forecast could materially change in such a relatively short period of time.

APS believes this letter has been responsive to the issues discussed above and would request admission of the letter and its attachments as APS Exhibit 23 in accordance with the procedure outlined by your honor on September 19.

Sincerely,

Thomas L. Mumaw

Thomas L. Mumaw

Attorney for Arizona Public Service Company

TLM/Attachments

Original and 13 copies of the foregoing filed this 14th day of October 2008 with:

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and

Copies of the foregoing emailed or mailed this 14th day of October 2008 to:

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Attachment 1

Arizona Public Service Company
Cost Efficiency Program Impact on Construction Expenditures Projection 2009 - 2011
$Millions

Attachment 1
Page 1 of 3

line		2009	2010	2011	3 - yr Total
1	**2008 Rate Case Forecast per note below**	**1,085**	**993**	**964**	**3,042**
	Changes as a result of the Cost Efficiency Program:				
	Production				
	Nuclear (APS Share)				
2	Nuclear Fuel	-	-	-	-
3	Reactor Vessel Head, Units 1, 2, 3	-	-	-	-
4	Evap Pond & Reservoir Liner Replacement	-	-	-	-
5	Cooling Tower Replacement, Unit 1	-	-	-	-
6	Rapid Refueling Package	-	-	-	-
7	Other Nuclear Power Plant Improvements - Includes regulatory, safety, reliability, or efficiency projects not listed above	-	-	-	-
8	Total Nuclear	-	-	-	-
	Fossil (APS Share)				
9	Cholla Environmental- Includes Baghouse, Scrubber, and other Environmental projects	(24)	(47)	18	(53)
10	Four Corners Environmental - Includes NOX abatement, particulate control, and other Environmental projects	1	-	19	20
11	Navajo Environmental - Includes NOX abatement and other Environmental projects	1	-	-	1
12	Other Coal Plant projects - Includes regulatory, safety, reliability, and efficiency projects at coal plants	(9)	(24)	(8)	(41)
13	Environmental Projects at Gas Plants	(2)	1	3	2
14	Long-Term Service Agreement Costs at Redhawk, West Phoenix	(29)	25	(1)	(5)
15	Other Plant projects - Includes capital costs for regulatory, safety, reliability, and efficiency projects at gas plants, and Childs/Irving Decommissioning	(3)	(14)	7	(10)
16	Total Fossil	(65)	(59)	38	(86)
17	**Total Production**	**(65)**	**(59)**	**38**	**(86)**

Note: This forecast is included in the Direct Testimony of Donald E. Brandt (Docket No. E-01345A-08-0172) as Attachment DEB-3. The forecast provided here differs from that provided in Attachment DEB-3 only in terms of years shown. Attachment DEB-3 shows the Company's forecast for 2008-2010 as of June 2008, consistent with the Company's asking in that case. The projections shown here are for years 2009-2011, to give the background necessary to show the impact of the recent Cost Efficiency Program (which will be seen in that timeframe) on the Company's overall forecast at the time of the rate case.

Arizona Public Service Company
Cost Efficiency Program Impact on Construction Expenditures Projection 2009 - 2011
$Millions

Attachment 1
Page 2 of 3

line		2009	2010	2011	3 - yr Total
	Transmission & Distribution				
	Transmission				
	Selected Major Transmission Projects				
18	Palo Verde - TS5 - TS9 TS5 to be located northwest of White Tanks; TS9 to be located near existing Raceway substation	(47)	(30)	(86)	(163)
19	TS5 - TS1 - Palm Valley TS1 to be located southwest of 195th Av & Deer Valley	(10)	(3)	4	(9)
20	TS9 - Pinnacle Peak 500kV	46	(18)	-	28
21	Palo Verde - North Gila 500kV	(30)	(37)	22	(45)
22	All Other Transmission Infrastructure Additions & Upgrades - includes Line & Substation additions & upgrades for 69kV and above voltage not listed above	(28)	(104)	(115)	(247)
23	Transmission Reliability Projects - includes Breaker, Capacitor, and Reactor projects, and other major reliability projects	7	(3)	-	4
24	Transmission relocations & emergency projects	-	-	-	-
25	**Total Transmission**	**(62)**	**(195)**	**(175)**	**(432)**
	Distribution				
26	Distribution Infrastructure projects - includes line & substations additions & upgrades	(29)	(39)	(28)	(96)
27	Distribution Reliability Projects - includes projects for substation, overhead, and underground equipment	-	2	(4)	(2)
28	Other Distribution Projects - Safety, Relocation / Conversion, Emergency, and other projects	13	15	10	38
29	**Subtotal, Distribution excluding Customer Construction**	**(16)**	**(22)**	**(22)**	**(60)**
	New Customer Construction (excl Schedule 3 CIAC)				
30	Meters (primarily AMI project)	19	28	20	67
31	Transformers	(6)	(14)	(23)	(43)
32	Service & Line Extensions	(19)	(32)	(91)	(142)
33	Street Light / Dusk-to-Dawn	1	1	-	2
34	**Total New Customer Construction excl Schedule 3 CIAC**	**(5)**	**(17)**	**(94)**	**(116)**
35	**Total Distribution excluding Schedule 3 CIAC**	**(21)**	**(39)**	**(116)**	**(176)**
36	**Total Transmission & Distribution**	**(83)**	**(234)**	**(291)**	**(608)**

Arizona Public Service Company
Cost Efficiency Program Impact on Construction Expenditures Projection 2009 - 2011
$Millions

Attachment 1
Page 3 of 3

line	General Plant	2009	2010	2011	3 - yr Total
37	Customer Service information systems	6	7	7	20
38	Distribution operations & work-management systems	23	9	8	40
39	All Other Info Sys Projects - includes infrastructure additions, equipment replacement, and all other Generation, T&D, and Shared Services systems & telecom	3	1	12	16
40	Deer Valley Operations Hub	(63)	(14)	86	9
41	Facilities - includes new service centers, upgrades of existing facilities, and replacements of mechanical equipment, plumbing, etc. at APS facilities.	(44)	(45)	(27)	(116)
42	Other General Plant	2	-	4	6
43	Total General Plant	(73)	(42)	90	(25)
44	**Total Change excluding Schedule 3 CIAC**	**(221)**	**(335)**	**(163)**	**(719)**
45	Schedule 3 CIAC	30	50	116	196
46	**Total Change including Schedule 3 CIAC**	**(191)**	**(285)**	**(47)**	**(523)**
47	**Construction Expenditure Projection as of October 2008**	**894**	**708**	**917**	**2,519**

Attachment 2

Attachment 2
Page 1 of 1

APS Construction Expenditure Projections
2005 Rate Case Forecast vs 2008 Rate Case Forecast
$Millions

Line		2005 Rate Case Forecast [A]				2008 Rate Case Forecast [B]				Change				Notes
		(1) 2008	(2) 2009	(3) 2010	(4) 3-yr Total	(5) 2008	(6) 2009	(7) 2010	(8) 3-yr Total	(5)-(1) 2008	(6)-(2) 2009	(7)-(3) 2010	(8)-(4) 3-yr Total	
1	Nuclear Fuel (APS Share)	41	59	55	155	93	117	110	320	52	58	55	165	C
2	Nuclear Plant Improvements (APS Share)	42	39	21	102	55	78	79	212	13	39	58	110	D
3	Fossil Plant Improvements (APS Share)	179	191	138	508	231	190	181	602	52	(1)	43	94	E
4	Transmission	222	283	182	687	208	317	288	813	(14)	34	106	126	F
5	Distribution, excluding Schedule 3 CIAC	307	317	326	950	299	248	260	807	(8)	(69)	(66)	(143)	G
6	General Plant - Information Systems, Facilities, Other	133	134	123	390	162	194	154	510	29	60	31	120	H
7	Total APS excluding Schedule 3 CIAC	924	1,023	845	2,792	1,048	1,144	1,072	3,264	124	121	227	472	
8	Schedule 3 CIAC	-	-	-	-	(25)	(59)	(79)	(163)	(25)	(59)	(79)	(163)	
9	**Total APS**	**924**	**1,023**	**845**	**2,792**	**1,023**	**1,085**	**993**	**3,101**	**99**	**62**	**148**	**309**	

A The forecast provided in the 2005 Rate Case (Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827) as Exhibit 27 was based upon August 26, 2006 projections. This forecast information was subsequently provided in the Financing Hearing (Docket No. E-01345A-06-0779), as Exhibit 4.

B The forecast provided in the 2008 Rate Case (Docket No. E-01345A-08-0172) as Attachment DEB-3 to Donald E. Brandt General Rate Case Testimony, was based on June 2008 projections.

C Changes principally due to increases in the cost of nuclear fuel.

D Changes principally due to changes in timing & scope of various plant improvement projects

E Changes principally due to changes in timing & scope of various plant improvement projects and increases to material prices

F Changes principally due to changes in timing & scope of various transmission projects and increases to material prices and right-of-way costs

G Changes principally due to recognized slower customer growth and efficiency initiative reductions, partially offset by changes in timing & scope of various distribution projects and increases in material prices

H Changes principally due to the addition of the Deer Valley Operations hub and changes in timing & scope of various facilities and information systems projects

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DOCKET CONTROL

November 26, 2008

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NOV 26 2008

AZ CORP COMM
Director Utilities

Commissioner Kristin K. Mayes
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: ***Request for Information Regarding Efforts by APS to Cut Costs; Docket No. E-01345A-08-0172***

Dear Commissioner Mayes:

In your letter of November 19, 2008, you asked for information regarding the efforts of Arizona Public Service Company ("APS" or "Company") to reduce its costs. Before responding to this request, it is important to keep in mind that the fundamental issue facing APS is that our prices do not reflect our cost of service either on a current or prospective basis. Neither the present financial crisis facing APS and its customers nor the long-term, substantial earnings shortfall that has been borne by APS shareholders are the result of a decline in productivity, reduced operational efficiency, poor reliability or lackluster customer service.

APS presently has only its third request for a base rate increase since 1991 pending before the Arizona Corporation Commission ("Commission"). That request, as you correctly note, is for $278.2 million annually, of which the Company has sought to implement $115 million (or just over 40% of the total) on an interim basis subject to refund. Even if this current base rate increase is granted in full, APS base rates will have only increased by a compounded rate of 1.2% per year since 1991, which is well below the overall rate of inflation (3.3%) present in the general economy during this same period. In fact, the cost of electricity for APS customers as a percentage of personal income has declined 22% since 1990. Thus, the Company believes that it has provided outstanding value for our customers. The Company has for years consistently requested that the Commission set rates that will recover on a timely basis only the reasonable cost of meeting the essential energy needs of customers in our service area. We regard such compensatory rates as both an economic necessity to allow APS to continue to provide reliable electricity service to the public and fully consistent with the requirements of both the Arizona and United States Constitutions.

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That said, APS continuously strives to control its costs. The most recent announcements of over $500 million in additional capital spending cuts or deferrals (bringing the total to date to approximately $720 million) and $50 million in O&M reductions clearly demonstrate APS's rigorous and continuing cost management culture, a business culture that has been in effect for many years at APS. The bottom line results of this way of doing business include some remarkable statistics:

- Despite having a relatively low density service territory (a little over 20 customers per square mile compared to nearly 300 customers per square mile for TEP and SRP), APS has nearly 1000 fewer employees now compared to 20 years ago, and its customer-to-employee ratio has improved from 98 to 227 during than same period, providing an increase of 130% in efficiency per employee.

- APS fossil fuel generating plants continue to operate at the highest levels of capacity factor and availability in the industry.

- Nuclear plant performance reached industry highs during the 1997-2001 period, and thanks to the ongoing Performance Improvement Plan, is returning to that level of performance with an anticipated annual capacity factor (including refueling outages) of approximately 84% for 2008. We also expect the NRC to remove Palo Verde from Column 4 oversight sometime next year.

- The Company's introduction of computer-aided standardized designs and the use of pre-fabricated components have reduced the manpower needed to build a new substation from 6-7 workers to 3-4 workers, while at the same time reducing construction time from 2-3 months to 3-4 weeks.

- The frequency of distribution-related APS customer outages has declined 67% from 1996 through 2007. The average duration of outages has declined 16 minutes (over 15%). APS expects in 2008 to break last year's reliability record for the lowest frequency of customer outages (clear weather SAIFI), and expects to improve over last year's performance on the duration of customer outages (SAIDI).

- Despite the decrease in the workforce, APS employees have twice won the highest award in the electrical industry for inventiveness and technical innovation. No other U.S. utility has received this award more than once during this same period.

- Overall non-production O&M levels (which provide an accurate comparison between electric utilities owning various levels of generation)[1] for APS fall well below our peers, both regionally and nationally. *See* Figure 1, below.

[1] Moreover, the Commission has already audited the Company's fuel costs and power production functions and found them to be reasonable.

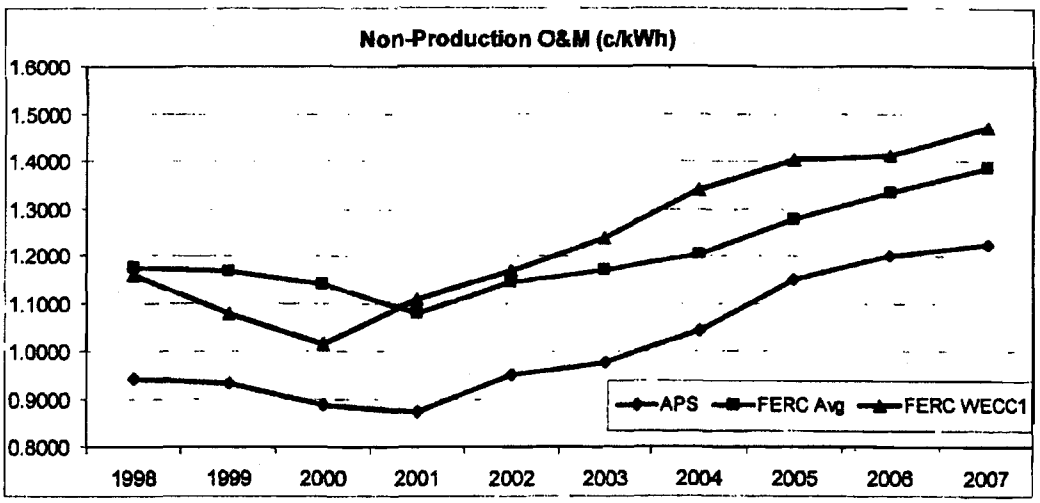

Figure 1: APS Non-Production O&M Comparison (FERC Form 1 Data)

You have asked whether APS considered several specific actions such as a blanket hiring "freeze," wage and salary freezes, and minimizing pay increases. Although the Company has considered many potential options for managing costs, to implement the measures cited in your letter would be harmful to both our short- and long-term operational performance, and would be counter to our customers' best interests. In fact, APS does not know of any comparable utility companies that have halted the hiring of necessary personnel, instituted blanket wage and salary freezes, or declined to pay employees appropriate compensation. Even in those "unregulated" companies characterized by failed business models and ineffective risk management (such as AIG or Lehman Brothers), these types of actions accompany a massive if not total reduction in services or reductions in output or both. Unlike these businesses, APS cannot pursue such value-destroying policies and practices, and due to its legal obligation to serve, APS cannot simply cut back on core services or output.

In a detailed letter from Jack Davis to the Commission dated August 1, 2006, Mr. Davis provided an exhaustive discussion of APS efforts to manage its costs over the years. These efforts have continued. Mr. Davis specifically indicated in that letter that the creation of new job positions at APS could only take place with his authorization as President of APS. Since Don Brandt has become President of the Company, he has maintained this policy. However, a complete cessation of all hiring would run counter to the best interests of the Company and its customers. The electric industry's workforce is rapidly aging, and there is an acute shortage of qualified utility employees nationwide. For this reason alone, APS must retain the ability to attract and retain such employees when the opportunity presents itself. Moreover, we must maintain critical positions at all times, and the training of the next generation of employees to the highest standards must continue.

The provisions of the collective bargaining agreements covering many APS employees render the limitation, let alone the elimination, of pay increases an impossibility. Although not subject to the same contractual agreements, but for the same reasons I discussed with regard to

the concept of a hiring "freeze," APS must remain competitive in the compensation it pays for both management and non-management personnel. To do less would sacrifice competency, professionalism and long-term efficiencies for minimal and, perhaps, illusory short-term gains. APS compensation levels are reasonable and comparable to peer companies, particularly given the demand for qualified utility personnel that we are seeing in our industry today.

Your letter also refers to the potential reduction or elimination of "management bonuses." The term "bonus" is actually not descriptive of the Company's incentive program. A "bonus" implies gratuitous additional compensation in excess of what the market requires to attract and retain employees at all levels. In that sense, APS pays no "bonuses." APS, like most utilities and many non-utility businesses, does have a component of each employee's compensation that falls under the heading of "at risk." "At risk" means that the level of this element of compensation depends upon performance – both individually and collectively. Thus, we and others refer to such compensation as "incentive" pay because it provides a direct and measurable incentive to achieve or surpass critical performance measures affecting the Company's operations. APS's outside compensation expert testified, without refutation by any other party, in the previous general rate case about the critical importance of the "at risk" component of overall employee compensation. Without this element, the Company could not compete for qualified executives, managers, and non-management employees with other companies using such compensation factors. The Commission recognized in the last APS rate case that these critical performance measures redounded in very large part to our customers' benefit, and thus cash incentive compensation should properly be included in APS's cost of service.

Allow me now to address some of the specific information you have requested:

1. Both the federal affairs and the public affairs groups are at Pinnacle West, and costs are allocated to APS and other affiliates. Lobbying-related expenditures for 2008 will total approximately $2.4 million, from a total federal and public affairs budget of $3.8 million. As you are no doubt aware, the Commission determined in the Company's last general rate case to effectively split these costs "50/50" between customers and shareholders. However, lobbying efforts have saved APS customers far more in the form of favorable legislation and administrative relief than even the full cost of such efforts. APS has previously provided significant detail on specific lobbying efforts that benefited customers in a November 26, 2007 letter to you from Meghan Grabel. In 2008, these efforts have focused on federal matters such as the extension of tax credits for renewable generation and state matters such as protecting our customers' interests in the Western Climate Initiative and working to try to minimize adverse impacts of state budget cuts on APS, its customers and the regulatory process in Arizona.

2. All employee incentive program compensation expended in 2008 has already been paid out. The APS expense was $6.7 million for officers and other senior management employees.

3. The Company's advertising budget anticipates that approximately $2.7 million of costs will be charged to the applicable regulatory accounts during 2008. This amount covers messaging solely around energy efficiency, conservation, renewables (other than that directly funded through the RES), and the "green choice" rate program. In addition, the DSM programs approved by the Commission have a marketing component, which includes approximately $1.2 million for advertising. Advertising related to the RES is separately budgeted and approved by the Commission as part of the overall category of RES marketing and outreach. For 2008, this RES-related marketing and outreach budget was $2.5 million. There is also some APS advertising related to safety messages. This safety-related advertising budget is about $200,000 for 2008. Finally, there is roughly $5000 of APS signage connected to charitable and civic events. That small amount is recorded "below-the-line" and paid for by APS shareholders. APS has no sports sponsorship costs for 2008.

4. The cost management efforts of APS have resulted in the reduction of some 550 positions. Of these, 375 positions were full-time employees, including 26 management positions, and 175 were contract employees.

5. The APS dividend to Pinnacle West for 2008 is $170 million. The dividend that APS has paid has not changed in well over a decade not withstanding equity infusions from Pinnacle West of over $700 million. Since 1996, this represents at least a 27% decline in the real (inflation adjusted) APS dividend to Pinnacle West and over a 50% decline in the dividend as a percentage of Pinnacle West's equity investment in APS.

APS understands the regulatory compact it has with the Commission. In the recent past, the Commission has examined the Company's operations and service quality in general rate cases, including the current proceeding in which Commission Staff alone has served some 25 sets of Data Requests (nearly 600 questions, often with numerous subparts) upon APS. The Commission has retained consultants to conduct specialized audits of fuel and power procurement and management, power plant operations, and hedging. Commission Staff itself has similarly reviewed APS's management of its financing costs. Neither Staff nor its consultants determined that APS managed these activities in an imprudent manner.

The capital and O&M cost savings announced during the second and third quarter conference calls focused primarily on 2009 and beyond. However, as APS has discussed in the Company's general rate case testimony, APS implemented some $14 million in O&M savings in 2008, including reductions in lobbying, advertising and communications costs. These cost savings also reflected reduced medical expenses resulting from changes to employee health care plans and reprioritizing, deferring or improving the efficiency of a variety of operations and maintenance work. Also, the initially-announced $200 million in capital expenditure reductions included work planned in 2008 as well as subsequent years.

APS understands the need to maintain customer service to the greatest extent possible. Certainly, this means balancing the level of service provided with the costs associated with such service levels. However, APS does not want short-term considerations to undermine an established record of improving customer service and satisfaction. Neither should cost-cutting be asked to come at the expense of environmental stewardship, our communities or the implementation of technological innovations such as advanced metering infrastructure. Each of these elements has an important call on the Company's responsibility as Arizona's largest electric utility.

While we understand that price increases are unpopular, including those driven by fuel costs outside the control of APS and this Commission, APS has received high ratings in customer satisfaction. Over the last several years, APS has ranked among the highest investor owned utilities in the Western United States in J.D. Power studies of customer satisfaction. Certainly, a major commitment to customer-friendly technology has enhanced customer satisfaction, such as installing over 150,000 "smart" meters, designing a state of the art website (ranked the 6th best in North America by E-Source), and demonstrating its overall dedication to the best in information technology (ranked 1st by the technology trade publication *Information Week*). APS employees work hard to support our communities, including thousands of volunteer hours donated to a wide array of causes and activities. APS's general efforts have benefited economic development in at least 40 separate Arizona communities or regions, promoted educational opportunities for Arizona students, and provided support to environmental and other important community projects. Also, in 2008, the Better Business Bureau awarded APS the Business Ethics Award.

Environmental stewardship informs many of the actions undertaken by APS. Beginning with its becoming the first utility to join the Coalition for Environmentally Responsible Economies in 1994 to its 2006 Climate Protection Award by the EPA, APS has become a recognized leader in the field of environmental and economic sustainability. Indeed, APS can claim status as the only Arizona company and only one of two U.S. utilities to rank among the world's 100 Most Sustainable Corporations. It enjoys a AAA rating from Innovest as being at the top of its industry in economic innovation, as well as concern for the environment and the community. APS continues to demonstrate its long-standing concern for the environment by providing its customers with the option of purchasing energy generated from renewable sources of electricity and by conserving electricity through energy efficiency and demand response.

With this Commission's support and policies, APS has become a leader in renewable resources particularly after the Commission's enactment of the Renewable Energy Standard ("RES"). With advent of the RES, however, APS has increased its renewable portfolio over thirty-fold since just 2005. With Solana and similar facilities and assuming the Company has the financial capability, APS has a goal of producing nearly half of its incremental needs in the years ahead through renewable resources. APS customers can contribute directly through both participation in distributed renewable energy projects and by subscribing to one of the Company's "green" power pricing options.

Again with Commission support, APS has instituted a number of cost-effective demand side management and energy efficiency programs. Just through 2007, these will result in 1.7 million MWH in lifetime energy savings. Notwithstanding the adverse impacts to the Company's financial performance from implementing effective energy efficiency programs, APS has increased its 2008 spending on energy efficiency by some 20% over 2007 levels, and for the second straight year, the EPA and the Department of Energy named APS an Energy Star Partner. Assuming continued regulatory support, APS hopes to increase its commitment to at least $25 million per year beginning in 2009. Recently, APS submitted for Commission approval a demand response program for general service customers. If approved, this will become the first of such programs, as APS anticipates providing an ever-increasing share of its additional capacity and energy needs through customer-based programs for demand reduction and energy efficiency.

We hope that the information contained in this letter responds to your requests and also helps the Commission view our present circumstances in an appropriate context. Challenging times often call for difficult decisions. When dealing with a vital service such as electricity, we need to avoid marginal solutions that may result in compromising important long-term values such as efficiency, reliability, safety, the environment and service to our communities. We take all of these factors into consideration each and every day in all of our business decisions, never losing sight of the long-term objectives we must pursue. APS looks forward to working with the Commission to providing the best possible service to our over one million customers.

Sincerely,

Thomas L. Mumaw

Thomas L. Mumaw

cc: Mike Gleason, Chairman
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Jeff Hatch-Miller
Gary Pierce
Ernest Johnson
Janice Alward
Lyn A. Farmer
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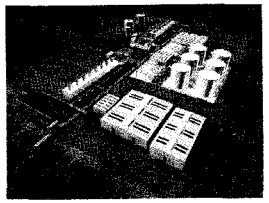
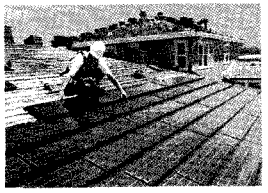
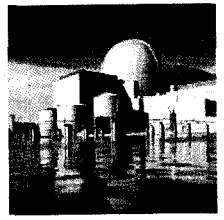
EXHIBIT
APS 32
ADMITTED

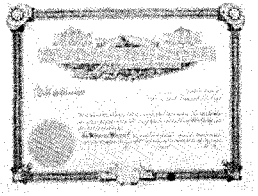
Equity Is Not A Substitute For Revenue

Equity Raised Does Not Diminish the Need for Earnings









Financing = $ for future infrastructure Investment

Rates = $ for day-to-day expenses

Example: Mortgage versus Salary

EXHIBIT
Aps 33
ADMITTED

IMPACT OF UNDEREARNING ON ACTUAL FFO TO DEBT RATIOS

December 2003 to December 2008

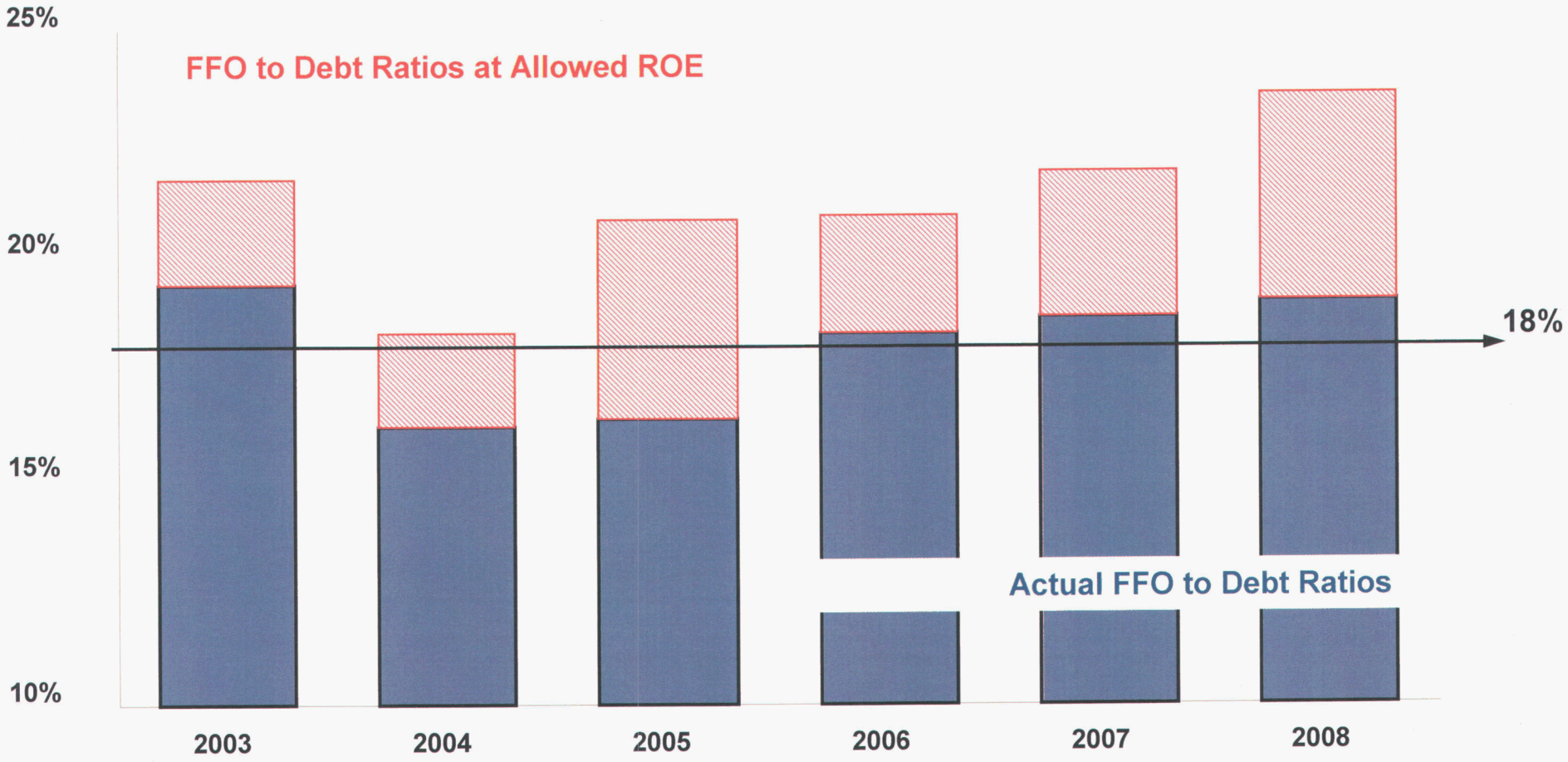


EXHIBIT
APS 34
ADMITTED

CREDIT RATINGS DISTRIBUTION
INVESTOR-OWNED ELECTRIC UTILITIES

AS OF AUGUST 21, 2009 STANDARD & POORS

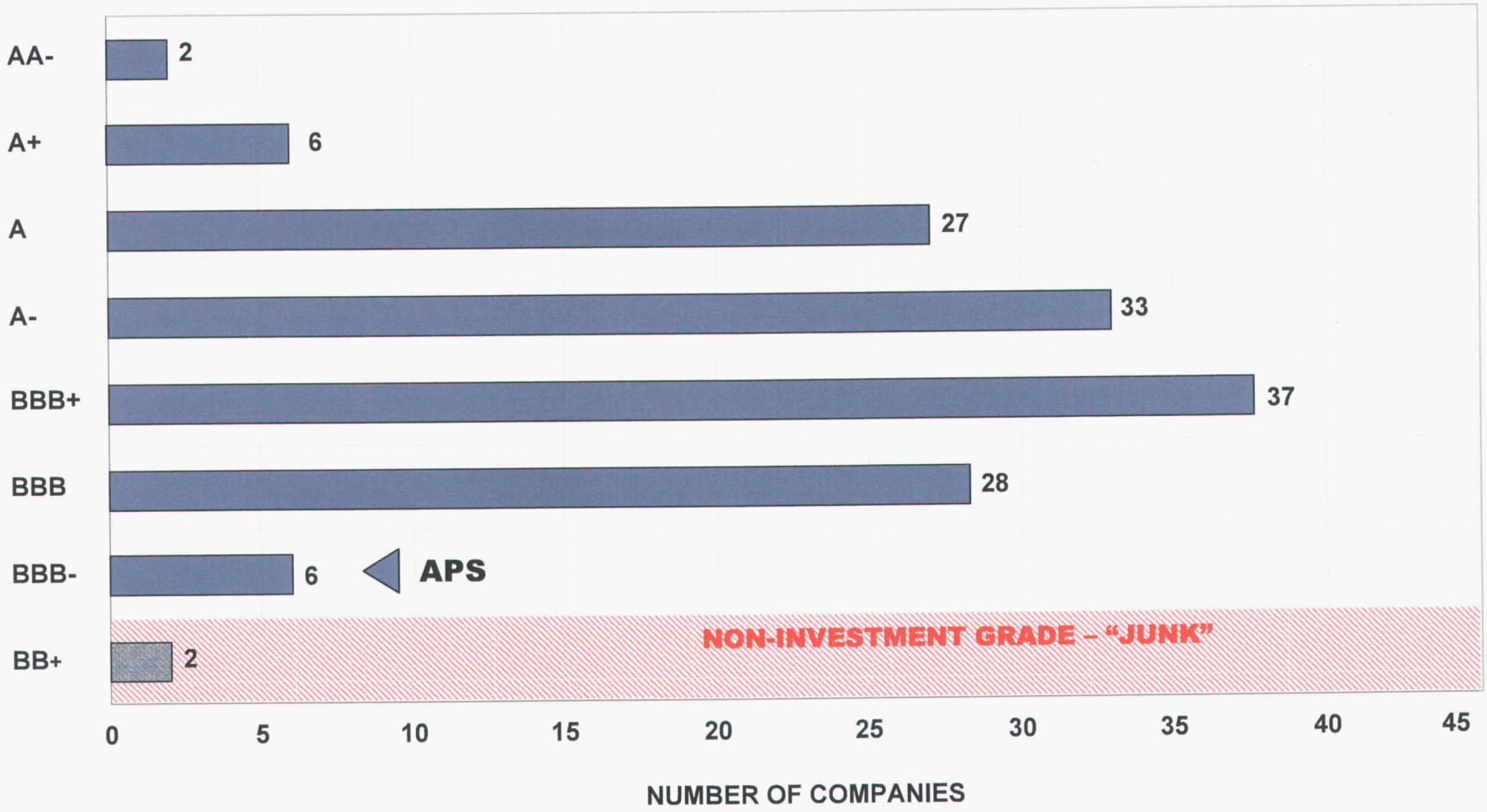
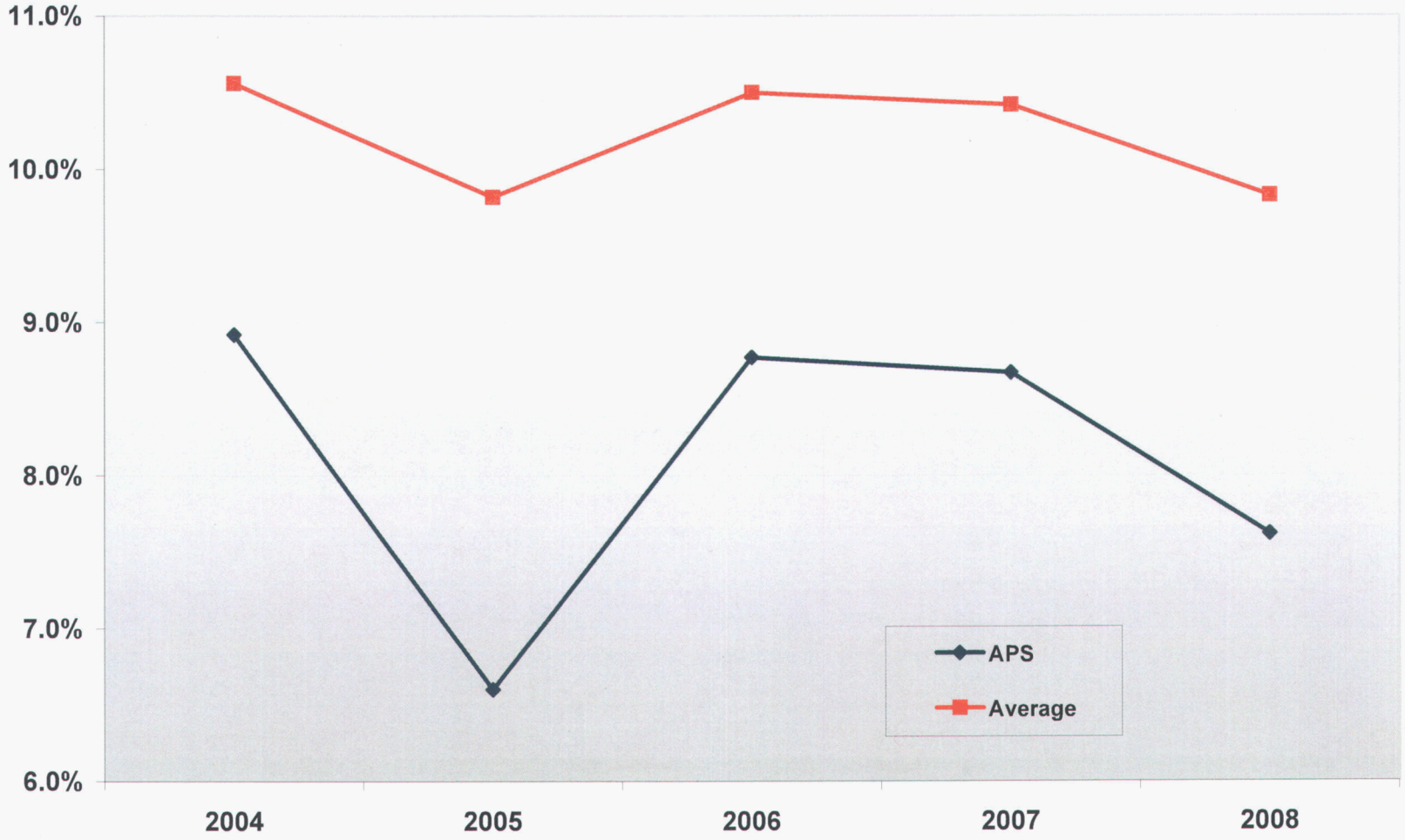


EXHIBIT
APS 35
ADMITTED

Actual Earned Return on Equity
(APS v. Industry Average[1] 2004 - 2008)[2]



1 - The companies used in this comparison are electric only, publicly owned operating companies that have more than 100,000 customers and own at least 20% of their base load generation. These are the companies against which APS competes for equity investment.

2 - Under the Settlement Agreement, APS anticipates that it will earn ACC-Jurisdictional ROE's of 9.4% in 2010, 8.4% in 2011, and 8.1% in 2012.

EXHIBIT
APS-37
ADMITTED

Monthly Bill
Rate Case Settlement Proposal
Revised September 17, 2009, Updated TCA Charge

ARIZONA PUBLIC SERVICE COMPANY
Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 33% of 2009 Carry Forward Costs Recovered in 2010
Revised Projection of 2010 PSA levels to be Reset with Proposed Base Rates

Residential (Average - All Rates)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)		Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	1,177	1,177		1,417	1,417	936	936
Base Rates	$ 116.78	$ 131.66		$ 151.17	$ 170.44	$ 82.38	$ 92.88
PSA- Forward Component	5.98	(1.77)		7.20	(2.13)	4.75	(1.40)
PSA - Historical Component	0.31	(2.94)		0.37	(3.54)	0.24	(2.34)
Interim Rate Adjustor (January 2009)	2.66	-		3.20	-	2.12	-
TCA (July 29, 2009)	2.66	2.66		3.20	3.20	2.11	2.11
CRCC (April 2005)	0.40	0.40		0.48	0.48	0.32	0.32
EIS (July 2007)	0.19	0.19		0.23	0.23	0.15	0.15
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.72	0.72		0.86	0.86	0.57	0.57
Total	$ 132.87	$ 134.09		$ 169.88	$ 172.71	$ 95.81	$ 95.46
Bill Impact (3)		**$ 1.22**			$ 2.83		$ (0.35)
Percent Bill Impact		**0.92%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 1.27	0.96%		$ 1.52		$ 1.01
Increase from Projected 2010 RES (5)		$ 0.24	0.18%		$ 0.24		$ 0.24

Residential (Rate E-12)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	763	763		880	880	645	645
Base Rates	$ 81.71	$ 92.19		$ 102.11	115.21	$ 61.30	69.16
PSA- Forward Component	3.88	(1.15)		4.47	(1.32)	3.28	(0.97)
PSA - Historical Component	0.20	(1.91)		0.23	(2.20)	0.17	(1.61)
Interim Rate Adjustor (January 2009)	1.73	-		1.99	-	1.46	-
TCA (July 29, 2009)	1.73	1.73		1.99	1.99	1.46	1.46
CRCC (April 2005)	0.26	0.26		0.30	0.30	0.22	0.22
EIS (July 2007)	0.12	0.12		0.14	0.14	0.10	0.10
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.46	0.46		0.53	0.53	0.39	0.39
Total	$ 93.26	$ 94.87		$ 114.93	$ 117.82	$ 71.55	$ 71.92
Bill Impact (3)		**$ 1.61**			$ 2.89		$ 0.37
Percent Bill Impact		**1.73%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 0.82	0.88%		$ 0.95		$ 0.69
Increase from Projected 2010 RES (5)		$ 0.24	0.26%		$ 0.24		$ 0.24

ARIZONA PUBLIC SERVICE COMPANY
Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 6/30/09
Revised RES, DSMAC 33% of 2009 Carry Forward Costs Recovered in 2010
Revised Projection of 2010 PSA levels to be Reset with Proposed Base Rates

Commercial (Rate E-32)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)		Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	8,769	8,769		9,746	9,746	7,792	7,792
Base Rates	$ 781.15	$ 884.44		$ 921.60	$ 1,043.47	$ 640.69	$ 725.41
PSA- Forward Component	44.55	(13.16)		49.51	(14.62)	39.58	(11.69)
PSA - Historical Component	2.26	(21.93)		2.51	(24.37)	2.01	(19.48)
Interim Rate Adjustor (January 2009)	19.82	-		22.03	-	17.61	-
TCA (July 29, 2009)	21.51	21.51		23.90	23.90	19.12	19.12
CRCC (April 2005)	2.96	2.96		3.29	3.29	2.63	2.63
EIS (July 2007)	1.41	1.41		1.56	1.56	1.25	1.25
RES (Jan 1, 2009)	69.60	69.60		77.35	77.35	61.85	61.85
DSMAC (April 2009)	6.52	6.52		7.24	7.24	5.79	5.79
Total	$ 949.78	$ 951.35		$ 1,108.99	$ 1,117.82	$ 790.53	$ 784.88
Bill Impact (3)		**$ 1.57**			$ 8.83		$ (5.65)
Percent Bill Impact		**0.17%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 9.43	0.99%		$ 10.48		$ 8.38
Increase from Projected 2010 RES (5)		$ 5.22	0.55%		5.80		4.64

Industrial (Rate E34/35 Medium Load Factor)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	2,250,284	2,250,284		2,344,877	2,344,877	2,155,690	2,155,690
Base Rates	$ 201,730.50	$ 228,929.00		$ 210,209.00	$ 238,550.00	$ 193,252.00	$ 219,308.00
PSA- Forward Component	11,431.45	(3,375.43)		11,911.98	(3,517.32)	10,950.91	(3,233.54)
PSA - Historical Component	580.58	(5,625.71)		604.98	(5,862.19)	556.17	(5,389.23)
Interim Rate Adjustor (January 2009)	5,085.64	-		5,299.42	-	4,871.86	-
TCA (July 29, 2009)	1,733.95	1,733.95		1,806.84	1,806.84	1,661.06	1,661.06
CRCC (April 2005)	760.60	760.60		792.57	792.57	728.62	728.62
EIS (July 2007)	360.05	360.05		375.18	375.18	344.91	344.91
RES (Jan 1, 2009)	353.78	353.78		353.78	353.78	353.78	353.78
DSMAC (April 2009)	2,106.39	2,106.39		2,194.93	2,194.93	2,017.84	2,017.84
Total	$ 224,142.94	$ 225,242.63		$ 233,548.68	$ 234,693.79	$ 214,737.15	$ 215,791.44
Bill Impact (3)		**$ 1,099.69**			$ 1,145.11		$ 1,054.29
Percent Bill Impact		**0.49%**					
Increase from Projected 2010 DSMAC (low income exempt) (4)		$ 3,557.53	1.59%		$ 3,707.07		$ 3,407.98
Increase from Projected 2010 RES (5)		$ 26.48	0.01%		26.48		26.48

Notes:
(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of September 1, 2009.
(2) Bill impacts reflect the proposed increase in base rates, reset of interim adjustor to zero, and reset of PSA to projected Feb 2010 levels to occur commensurate with the new base rates
(3) Bill impacts for commercial and industrial customers are less than residential on a percentage basis because these customer classes were assessed proportionally more for the interim adjustor and the PSA. The base rates reflect approximately the same percentage increase as residential.
(4) DSMAC costs reflect the 2010 implementation plan and the proposed Plan for Administration. 2009 carry forward costs are phased in over three years.
(5) RES impacts are based on the 2010 implementation plan filed in July 2009.
Of the projected increase in the RES budget for 2010, only about $1 to $2 million is attributable to the settlement.

PINNACLE WEST
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Facsimile: (602) 250-3393

September 17, 2009

Kristin K. Mayes, Chairman
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Responses to inquiries posed during the settlement hearings.

Dear Chairman Mayes:

During the hearing in the above-captioned matter, you posed a number of questions to APS that required follow-up. Attached, please find the Company's responses to several of those questions. Remaining questions from you and other Commissioners will be addressed either in testimony during the hearing or in later filings.

If you have any questions regarding the attached, please let us know.

Sincerely,

Meghan H. Grabel

Meghan H. Grabel

cc: Commissioner Gary Pierce
Commissioner Paul Newman
Commissioner Sandra Kennedy
Commissioner Bob Stump
Ernest Johnson
Steve Olea
Lyn Farmer
Janice Alward
Rebecca Wilder
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EXHIBIT
APS-38
ADMITTED

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Changes in APS Construction Forecast
Current forecast vs forecast filed October 2008

	2009	2010	2011	2009 - 2011 Total
Construction Expenditure Forecast as shown in Late Filed Exhibit 23 in this docket	**894**	**708**	**917**	**2,519**
Change to Nuclear Fuel, principally due to new price estimates	(40)	(47)	(33)	(120)
Changes due to scope & timing of other nuclear projects, including nuclear facilities projects	4	6	16	26
Changes due to scope & timing of Transmission & Distribution projects	22	-	-	22
Change to Schedule 3 CIAC for Local Facilities - *will be recorded as Revenue instead of CIAC for 2010 - 2012 if settlement is approved*	-	23	25	48
Change to Schedule 3 CIAC for System Facilities - these costs will not be reimbursed by Schedule 3 fees	-	6	7	13
Total Change	**(14)**	**(12)**	**15**	**(11)**
Current Forecast	**880**	**696**	**932**	**2,508**

Current APS Construction Forecast

line	Production	2009	2010	2011	3 - yr Total
	Nuclear (APS Share)				
1	Nuclear Fuel	77	63	73	213
2	Reactor Vessel Head, Units 1, 2, 3	7	1	-	8
3	Evap Pond & Reservoir Liner Replacement	10	11	14	35
4	Cooling Tower Replacement, Unit 1	7	19	22	48
5	Rapid Refueling Package	11	15	-	26
6	Other Nuclear Power Plant Improvements - Includes regulatory, safety, reliability, or efficiency projects not listed above	39	29	40	108
7	**Total Nuclear**	**151**	**138**	**149**	**438**
	Fossil (APS Share)				
8	Cholla Environmental- Includes Baghouse, Scrubber, and other Environmental projects	43	8	49	100
9	Four Corners Environmental - Includes NOX abatement, particulate control, and other Environmental projects	10	6	26	42
10	Navajo Environmental - Includes NOX abatement and other Environmental projects	3	2	1	6
11	Other Coal Plant projects - Includes regulatory, safety, reliability, and efficiency projects at coal plants	44	27	48	119
12	Environmental Projects at Gas Plants	2	8	3	13
13	Long-Term Service Agreement Costs at Redhawk, West Phoenix	4	58	5	67
14	Other Plant projects - Includes capital costs for regulatory, safety, reliability, and efficiency projects at gas plants, and Childs/Irving Decommissioning	19	13	25	57
15	**Total Fossil**	**125**	**122**	**157**	**404**
16	**Total Production**	**276**	**260**	**306**	**842**

Current APS Construction Forecast

		2009	2010	2011	3 - yr Total
	Transmission & Distribution				
	Transmission				
	Selected Major Transmission Projects				
17	Palo Verde - TS5 - TS9	1	-	2	3
18	TS5 - TS1 - Palm Valley	7	3	4	14
19	TS9 - Pinnacle Peak 500kV	132	13	-	145
20	Palo Verde - North Gila 500kV	-	3	66	69
21	All Other Transmission Infrastructure Additions & Upgrades - includes Line & Substation additions & upgrades for 69kV and above voltage not listed above	89	39	81	209
22	Transmission Reliability Projects - Includes Breaker, Capacitor, and Reactor projects, and other major reliability projects	36	29	20	85
23	Transmission relocations & emergency projects	6	6	6	18
24	**Total Transmission**	**271**	**93**	**179**	**543**
	Distribution				
25	Distribution Infrastructure projects - includes line & substations additions & upgrades	36	18	30	84
26	Distribution Reliability Projects - includes projects for substation, overhead, and underground equipment	52	58	56	166
27	Other Distribution Projects - Safety, Relocation / Conversion, Emergency, and other projects	28	33	32	93
28	**Subtotal, Distribution excluding Customer Construction**	**116**	**109**	**118**	**343**
	New Customer Construction (excl Schedule 3 CIAC)				
29	Meters (primarily AMI project)	51	60	55	166
30	Transformers	16	13	14	43
31	Service & Line Extensions	45	34	35	114
32	Street Light / Dusk-to-Dawn	5	5	4	14
33	**Total New Customer Construction excl Schedule 3 CIAC**	**117**	**112**	**108**	**337**
34	**Total Distribution excluding Schedule 3 CIAC**	**233**	**221**	**226**	**680**
35	**Total Transmission & Distribution**	**504**	**314**	**405**	**1,223**

Current APS Construction Forecast

		2009	2010	2011	3 - yr Total
	General Plant				
36	Customer Service information systems	19	19	17	55
37	Distribution operations & work-management systems	40	30	24	94
38	All Other Info Sys Projects - includes infrastructure additions, equipment replacement, and all other Generation, T&D, and Shared Services systems & telecom	43	37	55	135
39	Deer Valley Operations Hub	-	4	86	90
40	Facilities - includes replacements of mechanical equipment, plumbing, etc. and upgrades of existing facilities at APS	23	26	31	80
41	*Other General Plant*	4	6	8	18
42	**Total General Plant**	**129**	**122**	**221**	**472**
43	**Total APS excluding Schedule 3 CIAC**	**909**	**696**	**932**	**2,537**
44	Schedule 3 CIAC - to be recorded as Revenues instead of CIAC in 2010 - 2012 if settlement is approved	(29)	-	-	(29)
45	**Total APS**	**880**	**696**	**932**	**2,508**

Change in APS Construction Forecast
Current forecast vs forecast filed October 2008

line	Production	2009	2010	2011	3 - yr Total
	Nuclear (APS Share)				
1	Nuclear Fuel	(40)	(47)	(33)	(120)
2	Reactor Vessel Head, Units 1, 2, 3	(6)	(4)	-	(10)
3	Evap Pond & Reservoir Liner Replacement	(5)	3	8	6
4	Cooling Tower Replacement, Unit 1	-	-	-	-
5	Rapid Refueling Package	(1)	8	-	7
6	Other Nuclear Power Plant Improvements - Includes regulatory, safety, reliability, or efficiency projects not listed above	8	(11)	-	(3)
7	**Total Nuclear**	**(44)**	**(51)**	**(25)**	**(120)**
	Fossil (APS Share)				
8	Cholla Environmental- Includes Baghouse, Scrubber, and other Environmental projects	-	-	-	-
9	Four Corners Environmental - Includes NOX abatement, particulate control, and other Environmental projects	-	-	-	-
10	Navajo Environmental - Includes NOX abatement and other Environmental projects	-	-	-	-
11	Other Coal Plant projects - Includes regulatory, safety, reliability, and efficiency projects at coal plants	-	-	-	-
12	Environmental Projects at Gas Plants	-	-	-	-
13	Long-Term Service Agreement Costs at Redhawk, West Phoenix	-	-	-	-
14	Other Plant projects - Includes capital costs for regulatory, safety, reliability, and efficiency projects at gas plants, and Childs/Irving Decommissioning	-	-	-	-
15	**Total Fossil**	-	-	-	-
16	**Total Production**	**(44)**	**(51)**	**(25)**	**(120)**

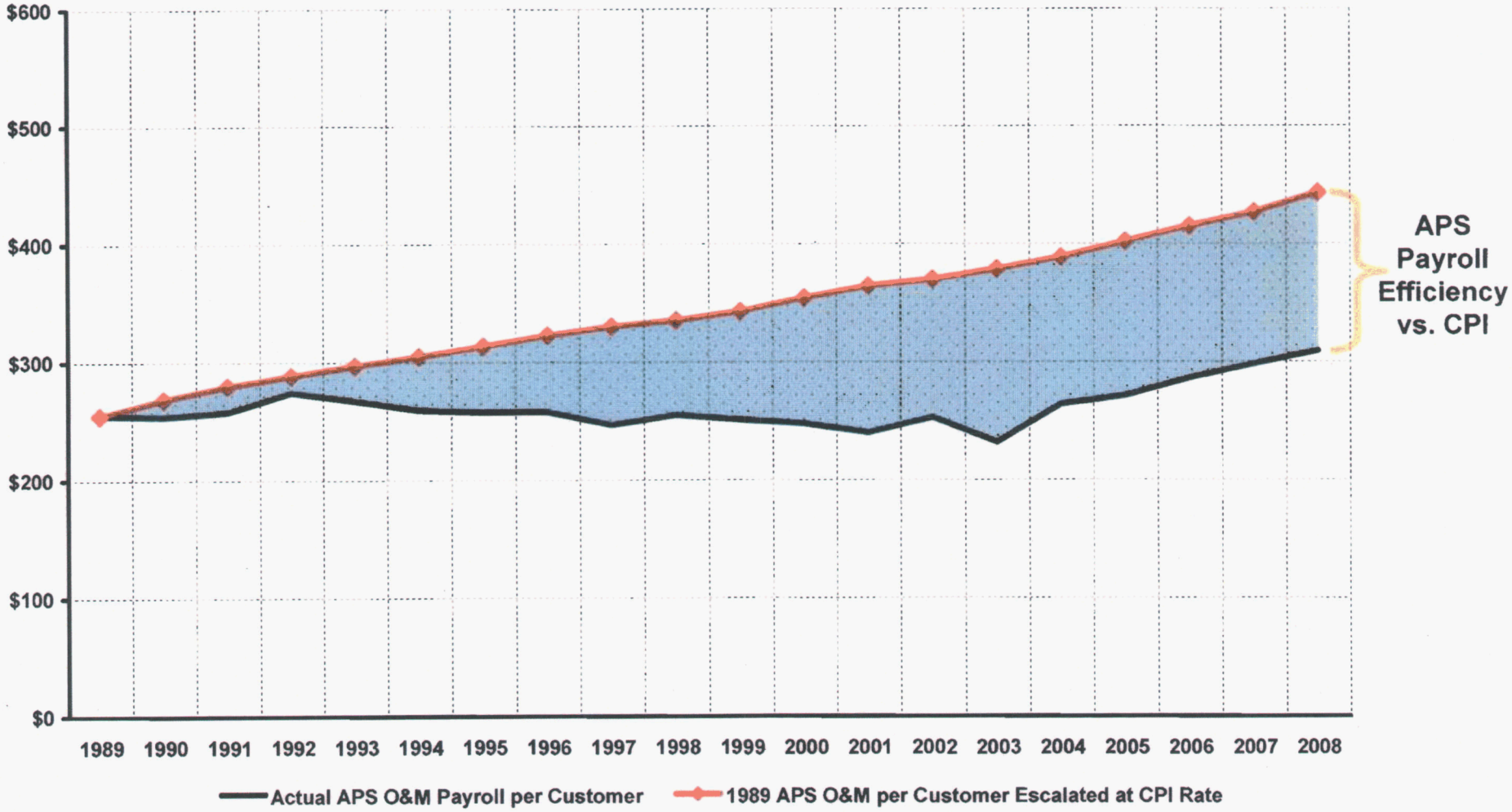
Change in APS Construction Forecast
Current forecast vs forecast filed October 2008

		2009	2010	2011	3 - yr Total
	Transmission & Distribution				
	Transmission				
	Selected Major Transmission Projects				
17	Palo Verde - TS5 - TS9 TS5 to be located northwest of White Tanks; TS9 to be located near existing Raceway substation	-	-	-	-
18	TS5 - TS1 - Palm Valley TS1 to be located southwest of 195th Av & Deer Valley	-	-	-	-
19	TS9 - Pinnacle Peak 500kV	4	-	-	4
20	Palo Verde - North Gila 500kV	-	-	-	-
21	All Other Transmission Infrastructure Additions & Upgrades - includes Line & Substation additions & upgrades for 69kV and above voltage not listed above	12	-	-	12
22	Transmission Reliability Projects - Includes Breaker, Capacitor, and Reactor projects, and other major reliability projects	-	-	-	-
23	Transmission relocations & emergency projects	-	-	-	-
24	**Total Transmission**	**16**	-	-	**16**
	Distribution				
25	Distribution Infrastructure projects - includes line & substations additions & upgrades	6	-	-	6
26	Distribution Reliability Projects - includes projects for substation, overhead, and underground equipment	-	-	-	-
27	Other Distribution Projects - Safety, Relocation / Conversion, Emergency, and other projects	-	-	-	-
28	**Subtotal, Distribution excluding Customer Construction**	**6**	-	-	**6**
	New Customer Construction (excl Schedule 3 CIAC)				
29	Meters (primarily AMI project)	-	-	-	-
30	Transformers	-	-	-	-
31	Service & Line Extensions	-	-	-	-
32	Street Light / Dusk-to-Dawn	-	-	-	-
33	**Total New Customer Construction excl Schedule 3 CIAC**	-	-	-	-
34	**Total Distribution excluding Schedule 3 CIAC**	**6**	-	-	**6**
35	**Total Transmission & Distribution**	**22**	-	-	**22**

Change in APS Construction Forecast
Current forecast vs forecast filed October 2008

		2009	2010	2011	3 - yr Total
	General Plant				
36	Customer Service information systems	-	-	-	-
37	Distribution operations & work-management systems	-	-	-	-
38	All Other Info Sys Projects - includes infrastructure additions, equipment replacement, and all other Generation, T&D, and Shared Services systems & telecom	2	-	-	2
39	Deer Valley Operations Hub	-	-	-	-
40	Facilities - All changes related to changes to Nuclear Facilities	8	10	8	26
41	Other General Plant	(2)	-	-	(2)
42	**Total General Plant**	**8**	**10**	**8**	**26**
43	**Total Change excluding Schedule 3 CIAC**	**(14)**	**(41)**	**(17)**	**(72)**
44	Change to Schedule 3 CIAC for Local Facilities - will be recorded as Revenue instead of CIAC for 2010 - 2012 if settlement is approved	-	23	25	48
45	Change to Schedule 3 CIAC for System Facilities - these costs will not be reimbursed by Schedule 3 fees	-	6	7	13
46	**Total Change**	**(14)**	**(12)**	**15**	**(11)**

APS Operations and Maintenance Payroll Costs Per Customer
1989 – 2008



Year	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Total APS O&M Payroll ($ in Millions)	$145	$148	$154	$167	$167	$166	$171	$178	$177	$191	$195	$200	$201	$221	$209	$246	$262	$288	$314	$336
Total APS Customers (in Thousands)	569	583	595	608	623	640	663	689	718	748	778	807	837	875	902	931	966	1,008	1,052	1,086

2008 Actual and 2009 Estimate of Advertising, Sports Contracts, and Lobbying ($ in Millions)

APS Advertising Expenses

	2008 Actual	2009 Estimate	
General Advertising	$ 4.4	$ 1.7	A
RES Tariff	1.5	5.4	B
DSM Surcharge	1.2	1.2	
Total	$ 7.1	$ 8.3	

A All general advertising is being used to support energy efficiency, renewables, safety and green choice programs.

B Approximately 90% of these amounts are targeted toward residential distributed generation.

Sports Contracts

	2008 Actual	2009 Estimate	
APS Sports Contracts	$ 0.0	$ 0.0	
Pinnacle West Sports Contracts	$ 4.1	$ 4.4	C

C The Pinnacle West sports contracts are not paid for by APS customers. However, the contracts include TV and radio spots that are being used solely for messaging related to APS energy efficiency, renewables and green choice programs. Therefore, APS customers receive this benefit at no cost. The increase in 2009 of $0.3M is solely the result of additional messaging for these programs.

APS Lobbying Expenses

	2008 Actual	2009 Estimate	
State and Federal Lobbying	$ 2.4	$ 2.1	D

D The Settlement Agreement does not provide for the recovery of any lobbying expenses. The Commission allowed 50% recovery of lobbying in the Company's last rate case, Decision No. 69663.

Spot Prices at Palo-Verde

		Palo-Verde On-Peak ($/MWh)	Palo-Verde Off-Peak ($/MWh)
2007			
	Q1	54.87	41.78
	Q2	65.15	41.18
	Q3	70.57	37.05
	Q4	57.73	44.44
	Average	62.11	41.11
2008			
	Q1	69.63	56.43
	Q2	90.37	62.46
	Q3	80.67	53.61
	Q4	44.38	33.48
	Average	71.21	51.45
2009			
	Q1	33.68	25.35
	Q2	30.07	18.50
	Average	32.93	21.98

SOURCE: Dow Jones

APS Retail Customers and Sales

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Electric Sales (MWh):									
Residential	9,780,680	10,334,860	10,443,820	11,147,195	11,527,402	12,223,576	12,993,961	13,771,481	13,368,015
Total retail	22,534,524	23,399,012	23,361,755	24,562,305	25,353,323	26,477,551	27,970,397	29,171,321	28,793,588
Year over Year Change in Sales									
Residential		5.7%	1.1%	6.7%	3.4%	6.0%	6.3%	6.0%	-2.9%
Total retail		3.8%	-0.2%	5.1%	3.2%	4.4%	5.6%	4.3%	-1.3%
Average customers									
Residential	749,285	776,339	801,801	828,366	859,069	896,472	936,464	966,013	977,944
Total retail	843,413	874,537	902,029	931,462	966,185	1,007,640	1,051,895	1,086,328	1,101,905
Year over Year Change in Customers									
Residential		3.6%	3.3%	3.3%	3.7%	4.4%	4.5%	3.2%	1.2%
Total retail		3.7%	3.1%	3.3%	3.7%	4.3%	4.4%	3.3%	1.4%
Retail Revenues (thousands):									
Residential	880,468	914,711	912,245	960,303	983,525	1,079,223	1,270,521	1,418,315	1,454,458
Total retail	1,815,682	1,867,338	1,845,563	1,917,807	1,964,264	2,121,093	2,510,180	2,772,955	2,898,549
Year over Year Change in Revenue									
Residential		3.9%	-0.3%	5.3%	2.4%	9.7%	17.7%	11.6%	2.5%
Total retail		2.8%	-1.2%	3.9%	2.4%	8.0%	18.3%	10.5%	4.5%

Revenue changes largely the result of changes in sales volume net of rate reductions in 2001, 2002, 2003, and 2004.

Revenue changes largely the result of changes in sales volume and higher fuel costs.

Post Test-Year Plant Additions

Amount included in Settlement Pro-Forma – 1/1/2008 through 6/30/2009	Actual net additions 1/1/2008 through 6/30/2009	Estimated, 7/1/2009 through 12/31/2010
$473M	$646M	$890M

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

EXHIBIT
ASBA-1
admitted

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, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-08-0172

Permanent Rate Case

Testimony in Support of Proposed Settlement Agreement

Of Robert Rice

On Behalf of

Arizona School Boards Association

July 1, 2009

DIRECT TESTIMONY OF ROBERT RICE
ON BEHALF OF ARIZONA SCHOOL BOARDS ASSOCIATION

(Docket No. E-01345A-08-0172)

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Robert Rice. My address is 463 West Kent, Chandler, Arizona 85225.

Q. WHAT IS YOUR POSITION?

A. I am the President of the Arizona School Boards Association, serve on the organization's Board of Directors and a member of the Chandler Unified School District Governing Board.

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of the Arizona School Boards Association. The Arizona School Boards Association ("ASBA") is a 501(c)(3) non-profit, membership-driven association of more than 240 Arizona public school governing boards. Its members represent 1200 plus school board members and over 1.12 million Arizona children. ASBA's mission is to promote community volunteer governance of public education and continue improvement of student success by providing leadership and assistance to public school governing boards.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This is the first time that ASBA has intervened in a utility rate proceeding at the Commission. In the past we have provided public comment but have been challenged by Commissioners to become more involved in rate proceedings to advance the interests of Arizona public schools and their governing boards. This case has represented our first effort at doing so. In entering this case as a party our hope was that we can provide support to our member districts in managing their energy demand, thus reducing their

costs, with the potential of having more funding available for school governing boards to devote to classroom learning. We believe this has been accomplished and urge the Commissioners to approve the proposed settlement which contains many positive provisions for Arizona's public schools.

Q. PLEASE DESCRIBE THE FUNDING OF ARIZONA'S PUBLIC SCHOOLS RELATIVE TO OTHER STATES.

A. By any measure, Arizona per-pupil education funding is low compared to other states. The American Legislative Exchange Council recently reported that among all of the 50 states plus Washington, D.C., only Utah spends less per pupil, placing Arizona in 50th place. This low funding level forces Arizona school districts and their governing boards to be as efficient as possible with the dollars that they receive.

Q. ARE THERE ANY CONSTRAINTS ON THE FUNDING THAT IS AVAILABLE TO ARIZONA'S PUBLIC SCHOOLS?

A. Yes. Arizona schools have seen great changes in the way utilities are funded. While there is a measure on the books that would allow school districts to recoup up to 90% of their total utility costs that exceed the so-called "excess utility" amount allowed in the 2008 school year, this already reduced funding is slated for cuts in the last iteration of the state budget. Regardless of the final outcome of the budget, it is safe to say that there are great incentives for Arizona school districts to manage their utility expenses to be as efficient as possible. The proposed settlement agreement greatly assists our member school districts in their efforts to conserve energy, reduce their utility demand and ultimately reduce the energy expenses and is strongly supported by our organization. Once again, we urge the Commission to support the negotiated proposed settlement.

Q. DO YOU HAVE ANY SPECIFIC RECOMMENDATIONS TO MAKE IN THIS PROCEEDING?

1 A, Yes. We urge the Commission to accept the settlement as presented which requires the
2 Arizona Public Service Company to work cooperatively with Arizona school districts to
3 ascertain and implement cost saving measures that can lower the utility demand that
4 school districts have. The settlement includes measures that will allow Arizona school
5 districts to be energy producers and not just consumers, including programs that assist
6 districts in attaining alternative energy production devices such as photo-cell solar panel
7 collectors and attendant equipment. Again, we urge the Commission to approve the
8 proposed settlement.
9 **Q. DOES THAT CONCLUDE YOUR TESTIMONY?**
10 A. Yes.

EXHIBIT
AECC-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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-08-0172**

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Settlement Agreement

July 1, 2009

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Are you the same Kevin C. Higgins who previously testified on behalf of AECC in the interim, revenue requirement, and cost of service/rate design phases of this proceeding?

A. Yes, I am. My qualifications were presented in my direct testimony filed in the revenue requirement phase of this case, with additional detail in Attachment KCH-1, attached to that testimony.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

1 **Overview and Conclusions**

2 **Q. What is the purpose of your testimony in this phase of the proceeding?**

3 A. I am testifying in support of the Proposed Settlement Agreement
4 ("Agreement") filed by Staff on behalf of the Agreement's Signatories on June
5 12, 2009. The proposed Agreement provides a comprehensive resolution of the
6 issues in the Arizona Public Service Company ("APS") general rate case.

7 **Q. Were you personally involved in the negotiations that resulted in the**
8 **Agreement?**

9 A. Yes, I participated in the negotiations on behalf of AECC.

10 **Q. What is your recommendation to the Commission with respect to the**
11 **Agreement?**

12 A. I recommend that the Agreement as submitted by the Signatories be
13 approved by the Commission. In my opinion, the Agreement produces just and
14 reasonable rates and is in the public interest.

15 **Q. Does AECC support the entire Agreement?**

16 A. Yes. The Agreement is a package that was crafted after extensive
17 negotiations among many parties over many weeks. AECC is recommending
18 adoption of each provision in the Agreement as a package deal.

19 **Q. How is your testimony in support of the Agreement organized?**

20 A. First, I offer some comments on the overall Agreement. I follow that
21 discussion with some specific comments on certain provisions of the Agreement
22 that are of particular interest to AECC.

1 **Overall Agreement**

2 **Q. Please provide a general overview as to why you believe the Agreement is in**
3 **the public interest and should be adopted.**

4 A. The Agreement provides a comprehensive resolution of the issues in the
5 APS general rate case. The broad scope of the Agreement is attested to by the
6 fact that it is supported by twenty Signatories with widely varying constituencies.
7 In my opinion, the Agreement strikes the appropriate balance between customer
8 interests and utility interests. Its adoption would provide APS an opportunity to
9 improve its financial condition while being fair to customers by not increasing
10 rates any more than is absolutely necessary. In support of the objective of
11 improving APS's financial condition, the Agreement commits APS to make a
12 minimum of $700 million of equity infusions through 2014 and obligates the
13 Company to undertake best efforts to attain an equity-to-total-capital ratio of 52
14 percent by the end of 2012.

15 In addition, the Agreement resolves the important rate case issues of
16 revenue spread and rate design in a just and equitable manner. The Agreement
17 also contains major provisions addressing increased energy efficiency and
18 renewable energy development.

19 The Agreement provides a plan for base rate stability by prohibiting APS
20 from filing its next two general rate cases prior to June 1, 2011 and June 1, 2013,
21 respectively. In connection with these provisions, the Agreement also provides
22 that no new base rates resulting from APS's next general rate case will be
23 effective prior to July 1, 2012. This "stay-out" will provide customers with an

assurance of stable base rates for a considerable period. In my opinion, this is a material benefit to customers. The Agreement also provides for the potential for Systems Benefits Charges to customers to be reduced in 2012 if a Palo Verde license extension is approved prior to the conclusion of the next rate case.

Revenue Requirement

Q. What does the Agreement provide with respect to revenue requirement?

A. Total base revenues (including fuel) will be set at a level that is $334.7 million greater than the base rates established in APS's last general rate case. [Paragraph 3.6][2] However, concomitant with this change, the forward component of the PSA Adjustor will be reset to zero. The net increase in rates that results from the increase in base rates and the resetting of the forward component of the PSA Adjustor to zero is $207.5 million, which is comprised of an increase in non-fuel base rates of $196.3 million, plus $11.2 million in fuel-related costs that are currently excluded from PSA recovery due to the 90/10 sharing, but which are properly recoverable by APS when new rates are established pursuant to a general rate case. [Paragraphs 3.3, 3.4] Both the total base revenue increase of $334.7 million and the non-fuel base rate increase of $196.3 million include the interim rate increase of $65.2 million awarded by the Commission in 2008 as part of this docket.

Q. How does your description of the base rate increase relate to the increase of $131.1 million noted in Paragraph 3.2 of the Agreement?

[2] References to paragraphs in brackets refer to paragraphs enumerated in the Agreement.

1 A. $131.2 million represents the incremental increase in non-base rates above
2 the $65.2 million increase awarded by the Commission on an interim basis, which
3 is consistent with my description above.

4 **Q. Why do you believe this revenue increase is reasonable?**

5 A. The revenue requirement recommended by the Agreement is $103.5
6 million less than APS had requested in its Application. In my direct testimony on
7 revenue requirement, I had recommended reducing APS's requested increase by
8 $101.5 million. As such, the reduction in APS's revenue requirement effected by
9 the Agreement and that recommended in my direct testimony are nearly identical,
10 obviously warranting my support. However, some further explanation may be
11 helpful.

12 In my revenue requirement testimony, I did not take a position either in
13 support of, or opposition to, APS's requested return on equity. Consequently, the
14 revenue adjustments in my direct testimony did not include an adjustment for
15 return on equity. Had I challenged APS's proposed return on equity, my
16 proposed reductions to APS's revenue requirement would have been greater.
17 Nevertheless, the final revenue requirement proposed in the Agreement is still
18 very close to the adjustments recommended in my direct testimony, which I
19 believe to be a reasonable result that is fair both to customers and to APS.

1 **Revenue Spread**

2 **Q. How does the Agreement resolve the issue of revenue spread?**

3 A. With two exceptions, the Agreement spreads the base rate increase across
4 all customer rate schedules on an equal percentage basis, inclusive of the interim
5 increase, and inclusive of fuel and purchase power costs that are incorporated into
6 base rates. [Paragraph 17.1] The exceptions are: (1) there will be no base rate
7 increase for low-income customers; and (2) within Rate E-32, there will be some
8 differentiation in the base rate increase among the four new rate categories of
9 Rate E-32 that are established in this case [Paragraph 17.2]. The separation of
10 Rate E-32 into four new rate schedules based on customer size – E-32-XS, E-32-
11 S, E-32-M, and E-32-L – is consistent with Staff's recommendation in APS's
12 previous rate case, Docket No. E-01345A-05-0816. To be clear, in the
13 Agreement, Rate E-32 *as a whole* receives the same equal percentage base rate
14 increase as all other rate schedules; as such, the differentiation of the base rate
15 increase within Rate E-32 does not impact any customers outside of Rate E-32.

16 Because the low-income customers who will receive no rate increase are
17 members of the Residential customer class, Residential customers as a whole will
18 receive a base rate increase that is slightly smaller than the overall average
19 pursuant to the Agreement. This result is shown in the "APS Rate Case
20 Settlement Proposal Bill Impact Analysis," filed by Staff on behalf of the
21 Signatories on May 15, 2009. The table on page 2 of the document shows the
22 overall average base rate increase (including interim and fuel) to be 13.07 percent,
23 whereas the Residential base rate increase (including interim and fuel) is 12.82

percent. Residential customers who pay the base rate increase will pay approximately the same percentage increase as the overall average.

Q. What is your assessment of the revenue spread in the Agreement?

A. In my opinion, the revenue spread is reasonable in the context of the overall Agreement. I note that the revenue spread in the Agreement is almost identical to the revenue spread recommended in Staff's direct case, which called for an equal percentage increase in base rates for all rate schedules except low income, inclusive of fuel costs (and inclusive of any interim increase).[3]

The revenue spread in the Agreement treats customer rate impacts on a basis that is directly comparable to the measurement of class revenue deficiencies in APS's cost-of-service study filed as part of APS's direct case. In other words, APS's class cost-of-service study measures the base rate increase necessary – including fuel – for each rate schedule to pay rates equal to its respective cost of service. The base rate increase in the Agreement is measured on the very same basis, i.e., base rate changes inclusive of fuel, but does not set each rate schedule exactly equal to its cost of service. However, in the context of the overall Agreement, this treatment is reasonable.

Q. Please explain.

A. APS's cost-of-service study, which was conducted in a manner consistent with the Commission's directives in its decision in Docket No. E-01345A-05-0816, indicates that to achieve rates equal to cost of service, the percentage base rate increase (including fuel) for industrial customers (Rates 34 and 35 taken

[3] Staff Exhibit FWR-3.

together) should be approximately equal to the system average increase – which is what the Agreement provides. The study further indicates that to achieve cost-based rates, the base rate increase for Residential customers (including fuel) should be approximately 4.7 percent above the system average, and that rates for Rate E-32 (as a whole) should be approximately 6.3 percent below the system average. Within Rate E-32, the Company's study shows that Rate E-32-L warrants a much smaller increase than the E-32 average, whereas Rate E32-XS warrants an increase that is above the average for the overall system.[4] As I noted above, the Agreement takes account of these differences among E-32 customers by awarding a modestly smaller base rate increase for Rate E-32-L and a modestly greater than average increase for Rate E-32-XS.

In the context of the overall Agreement, applying an equal percentage increase to Residential customers (excluding low income) and Rate E-32 is reasonable, in that the E-32 customers most deserving of a smaller-than-average increase (E-32-L) are acknowledged through the adjustments (discussed above) within E-32. With the treatment of E-32-L reasonably addressed within the E-32 group, I believe it is reasonable in the context of the overall Agreement for Residential customers (excluding low income) to pay the same percentage base rate increase as the system average, thereby mitigating, as much as reasonably possible, the impact of the rate increase on Residential customers.

[4] Source: APS Supplemental Filing: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls, Tab:"Cost of Service," lines 1378-1379. These results are also summarized in the "Base Rate Change" column of Table KCH-2 on page 11 of my Cost of Service direct testimony.

1 **Rate Design**

2 **Q. What does the Agreement provide with respect to rate design?**

3 A. Paragraph 18.3 of the Agreement provides that the rate increases for Rates
4 E-34, E-35, and E-32-L will be implemented by adopting APS's proposed
5 customer charges along with equal percentage increases in the demand and energy
6 charges for the rate schedules. This provision ensures that, within these rate
7 schedules, higher-load-factor and lower-load-factor customers will receive the
8 same percentage base rate increase. That is, the rate increase is not biased either
9 for, or against, customers based on load factor, which is reasonable in the context
10 of the overall Agreement.

11 Paragraph 18.1 of the Agreement provides that the voltage discount for E-
12 35 customers will be adjusted by the percentage change in E-35 base rates,
13 thereby maintaining consistency with the current rate design. Paragraph 18.2
14 eliminates a proposal by APS to assign certain third-party transmission costs to E-
15 34 and E-35 customers, a proposal which I argued was unreasonable in my direct
16 testimony. Both Paragraphs 18.1 and 18.2 reasonably maintain the status quo on
17 the issues to which they pertain.

18

19 **DSM and Self-Direction**

20 **Q. Please explain the self-direction provisions of the DSM section of the**
21 **Agreement.**

22 A. Self-direction refers to a practice in which customers of sufficient size are
23 permitted to undertake their own energy efficiency measures using a portion of

the DSM charges that are collected directly from them. Participating customers would be reimbursed for the cost of approved energy efficiency projects from these funds. Self-direction programs are currently in place in Oregon and Utah.

As Arizona's commitment to DSM investment increases, it has become increasingly important for AECC members to achieve the opportunity for self-direction. Many larger customers have full-time energy personnel that direct their firms' energy efficiency efforts; while these companies are committed to making energy efficiency improvements, they object to subsidizing their competitors through conventional DSM rate mechanisms. Self-direction provides these customers with a structure for channeling their DSM charges to energy improvements in their own facilities while contributing to APS's overall DSM performance goals.

The APS Settlement Agreement approved in 2005 in Docket No. E-01345A-03-0437 provided that self-direction for larger customers would be studied; however, no concrete self-direction program was ever implemented. The DSM provisions in the Agreement [Paragraphs 14.3 through 14.5] move forward by establishing a self-direction program, the parameters of which are presented in Appendix C to the Agreement. Large customers using 40 million kilowatt-hours of electricity per year, aggregated over all of their APS facilities, would be eligible to participate. The self-direction program is structured as a "use it or lose it" proposition. Customers who enroll in the program would have two years to complete approved energy efficiency projects in order to utilize the eligible DSM monies recovered from them since the time of their enrollment; participating

customers that complete qualifying DSM projects would be able to continue recovering the cost of their DSM investment for a total of ten years (or until 100 percent project cost recovery is achieved, whichever occurs sooner) using the eligible portion of the funds recovered from them through their DSM charges. Unused self-direction funds flow back into the DSM pool for use in other projects. In my opinion, the self-direction option is an essential component of APS's DSM efforts going forward.

Interruptible Rates

Q. What does the Agreement provide with respect to interruptible rates?

A. Paragraph 19.1 of the Agreement requires APS to work with Staff and other interested parties to develop an Interruptible Rate Rider for Rate E-34 and E-35 customers that will be filed within 180 days of the Commission's approval of the Agreement. This provision is similar to a provision in the TEP Settlement Agreement approved in Docket No. E-01933A-07-0402. If structured properly, interruptible rates can be a cost-effective means for utilities to obtain reliable capacity. Yet APS does not have an interruptible rider in its tariff. In my opinion, it is important for interruptible service to be included in the Company's resource mix, as it can provide benefits for both the Company as well as the customers with the operational flexibility to perform under an interruptible rider.

1 **Palo Verde Life Extension**

2 **Q. Please describe the provisions in the Agreement dealing with Palo Verde life**
3 **extension.**

4 A. This topic is addressed in Section XI of the Agreement. The Agreement
5 provides that if APS receives Nuclear Regulatory Commission approval to extend
6 the life of the Palo Verde Nuclear Generating Station, then APS would be
7 authorized to adjust its depreciation rates used for recording Palo Verde
8 depreciation expense no sooner than January 1, 2012. This provision
9 accomplishes at least two important objectives within the Agreement:

10 (1) It provides a means through which APS can improve its net income in
11 a future period without having to increase customer rates; this occurs through the
12 authorized reduction of APS's depreciation expense that would accompany
13 approval of Palo Verde life extension. While the benefit of the lower depreciation
14 expense would be retained by APS on a temporary basis, this is comparable to
15 what occurs whenever a utility reduces expense between rate cases. When new
16 rates are established pursuant to a subsequent rate case, the full benefit of the
17 reduced depreciation expense would be flowed through to customers on a going-
18 forward basis.

19 (2) A life extension for Palo Verde would reduce the annual funding
20 requirement for plant decommissioning, which is recovered through the System
21 Benefit Charge. If Palo Verde life extension is approved, the Agreement requires
22 APS to apply to the Commission to reduce the System Benefits Charge in an
23 amount equal to the corresponding reduction in the annual decommissioning

1 funding obligation, and to reduce the Power Supply Adjustor by the amount of the
2 associated reduction in spent fuel storage costs. Such reductions would produce
3 an annual revenue requirement benefit to customers.
4 In my opinion, the treatment of Palo Verde life extension costs represents
5 a creative solution that bridges the litigation differences among various of the
6 Signatories to enable the crafting of a successful package. The provision provides
7 important benefits for customers and the Company without raising rates. I
8 strongly support its adoption along with the other provisions of the Agreement.
9
10 **Q. Does this conclude your direct testimony?**
11 A. Yes, it does.

EXHIBIT
AECC-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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-08-0172**

Reply Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice and Competition

Settlement Agreement

August 6, 2009

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REPLY TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Are you the same Kevin C. Higgins who previously filed direct testimony in support of the Settlement Agreement on behalf of AECC, and also testified in the interim, revenue requirement, and cost of service/rate design phases of this proceeding?

A. Yes, I am. My qualifications were presented in my direct testimony filed in the revenue requirement phase of this case, with additional detail in Attachment KCH-1, attached to that testimony.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

1 **Overview and Conclusions**

2 **Q. What is the purpose of your reply testimony in this phase of the proceeding?**

3 A. I am responding to the testimony submitted by Barbara Wyllie-Pecora and
4 other individuals in opposition to the Proposed Settlement Agreement
5 ("Agreement").

6 **Q. What recommendations do you offer in your reply testimony?**

7 A. In general, the parties in opposition to the Agreement are proposing to
8 modify Service Schedule 3 to include a provision for 1,000 feet of "free footage"
9 for residential line extensions, up to a cost of $25,000. I recommend that these
10 proposals be rejected, and that the Agreement as submitted by its signatories be
11 approved by the Commission.

12

13 **Service Schedule 3**

14 **Q. What is Service Schedule 3?**

15 A. Service Schedule 3 sets out the terms for line extensions in the Arizona
16 Public Service Company ("APS") service territory.

17 **Q. What aspect of Service Schedule 3 is the primary source of the objection for**
18 **the parties in opposition to the Agreement?**

19 A. The parties in opposition to the Agreement have indicated their objections
20 to the provision in Service Schedule 3 that requires an APS residential customer
21 seeking a line extension to bear the full cost of it themselves. This requirement
22 was previously approved by the Commission and has been in place since July
23 2007. Prior to that date, an APS residential customer seeking a line extension was

granted a "free allowance" for 1,000 feet, so long as the cost did not exceed $25,000. Generally, the parties in opposition to the Agreement are seeking a return to the prior "free allowance" policy for residential customers.

Q. Is a return to the prior "free allowance" policy consistent with the Agreement?

A. No. The Agreement proposes to maintain the Commission's current policy regarding customer payments for line extensions, with modifications to provide for: (1) a clarified definition of Local Facilities, (2) a schedule of charges, (3) provision for itemization of quotes, and (4) procedures for refunding amounts to customers when additional customers connect to the line extension. In addition, the Agreement provides that "Schedule 3 shall expressly permit customers to hire contractors for trenching, conduit, and backfill necessary for the extension, as is currently permitted." Thus, while these modifications clarify and improve Schedule 3, the principle underlying the current policy that assigns costs to the cost causers is preserved in the Agreement.

Q. Are there other implications for the Agreement associated with the "free allowance" proposal?

A. Yes. Significantly, the Agreement provides that the Schedule 3 proceeds will be recorded as revenues by APS during the period from January 1, 2010 through either the earlier of December 31, 2012 or the conclusion of APS's next general rate case. If the proceeds are reduced as a result of Commission modifications to Schedule 3, then the Agreement provides that "offsetting revenue changes should also be ordered that would make any such modification(s)

revenue neutral" with respect to the provisions of the Agreement, i.e., the Agreement provides that the shortfall should be made up through a bigger rate increase than is already provided in the Agreement.

Q. As a matter of ratemaking principle, do you concur with the current Schedule 3 policy?

A. Yes, I do. One of the fundamental principles in ratemaking is that costs should be assigned to cost causers to the greatest extent practicable. This objective is accomplished under the general policies in place in current Schedule 3. The Agreement identifies a number of areas in which the Schedule 3 provisions can be improved or clarified, while remaining true to this basic principle. In contrast, under the "free footage" concept, the footage is only free to the cost causer; the costs incurred to extend the lines are simply shifted to the other customers on the system. Frankly, such an approach is inequitable to existing customers. It is also inefficient, in that the true cost of extending power lines is understated to the private decision maker.

Q. Please explain what you mean by this last point.

A. If the true cost of extending power lines is not included in the decisions made by individuals purchasing land and building homes, but instead is socialized to other parties, then it can result in more expensive options being selected than would otherwise occur. This point is even alluded to in the report filed by Ms. Wyllie-Pecora entitled, "Arizona Utilities – Modifications to Infrastructure Extension Policies Impact Analysis." On page 25 of the report, the authors note that one consequence of assigning line extension cost responsibility to the land

1 developer is that customers may instead "purchase a home where electrical
2 service extensions are already paid for or are not as costly." In my opinion, these
3 considerations are exactly what *should* take place under a rational policy. It is *not*
4 sound public policy to mask these costs so that they are not taken into account in
5 private decision making.

6 **Q. Has your record of participation in this case been one that is generally**
7 **adverse to the interests of new customers?**

8 A. No. While I believe that it is just and reasonable for new customers to be
9 responsible for the direct cost of line extensions to reach their premises, I am not
10 adverse to the concerns of new customers. I support a balanced approach. In its
11 initial filing, APS proposed even greater fees for new customers to recover
12 incremental distribution system costs. In my direct testimony, I opposed this
13 concept, arguing that such an approach raises many policy and economic
14 questions and can result in unintended consequences, including the undue stifling
15 of economic development. As part of the Agreement, APS's proposed impact
16 fees are withdrawn. Further, the Agreement proposes some improvements to the
17 Schedule 3 terms that are beneficial to new customers, which I fully support,
18 including procedures for refunding amounts to customers when additional
19 customers connect to the line extension.

20 In my opinion, the current Schedule 3 approach as modified by the
21 Agreement, which assigns to new customers the direct cost of extending service
22 to their premises, but which does not include an additional impact fee, strikes the

1 correct balance between fair consideration of the interests of new customers and
2 existing customers.

3 **Q. You referred to the report filed by Ms. Wyllie-Pecora entitled, "Arizona**
4 **Utilities – Modifications to Infrastructure Extension Policies Impact**
5 **Analysis." In your opinion, does the report provide a reasonable basis for**
6 **modifying Service Schedule 3 to provide for 1,000 feet of "free footage" for**
7 **residential line extensions?**

8 A. No, it does not. The report does not draw any specific conclusions
9 regarding the change in Service Schedule 3 and impacts on the Arizona land
10 market. In particular, the report makes no attempt to separate any impacts
11 attributable to changes in Schedule 3 from the impacts of the global recession and
12 the associated suppression of real estate values that has occurred nationwide
13 during the past year.

14 The primary analysis in the report is hypothetical in nature, in that it
15 examines certain economic and fiscal impacts associated with the construction (or
16 non-construction) of 100 houses. The report does not conclude that the absence
17 of a free-footage allowance has caused or will cause a change in the rural housing
18 stock of this magnitude. Moreover, even the hypothetical analysis presented in
19 the report does not present *net* impacts of a 100-house change, but only the *gross*
20 economic impacts from construction of 100 houses, viewed in isolation.

21 **Q. Please elaborate.**

22 A. Presenting only the gross impacts of constructing 100 houses overstates
23 the net fiscal benefit to local taxing jurisdictions as well as the net benefit to the

1 state economy as a whole. For example, the report estimates the local tax
2 revenues that could be generated from the construction of 100 new homes – but
3 without netting out any additional costs to the local governments of providing
4 services to these new residences. Thus, the limited presentation of the gross
5 impacts overstates the net fiscal impact on local government revenues. Further,
6 the analysis in the report does not consider that re-instituting the line extension
7 subsidy would cause a rate increase for remaining APS customers, and, thus it
8 fails to consider the economic effect associated with the diversion of these
9 customers' expenditures away from other goods and services toward higher utility
10 rates.

11 **Q. Are there other reasons for not relying on the report to modify Service**
12 **Schedule 3?**

13 A. Yes. The most important reason for not relying on the report to modify
14 Schedule 3 is that the report sidesteps the fundamental question of why other
15 electric power customers should be responsible to pay the line extension costs of
16 those seeking new service in the first instance. Even if the construction of new
17 homes could be spurred through the reintroduction of a line extension subsidy, I
18 see no reasonable basis for assigning the subsidy burden to the other electric
19 customers throughout the APS system. If indeed, local governments in the
20 affected areas were convinced that subsidizing line extensions would produce a
21 net fiscal gain, then it would be rational for those entities to consider funding the
22 subsidy themselves, as according to the thrust of the argument advanced by
23 subsidy proponents, these taxing entities would stand to gain. It does not follow

1 from this line of argument that responsibility for funding the subsidy should fall

2 somehow to the average electric power customer on the APS system.

3 **Q. Does this conclude your reply testimony?**

4 A. Yes, it does.

5 2224190.1/74326.809

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
AECC-3
~~ADMITTED~~

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-08-0172**

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Revenue Requirement

December 19, 2008

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Are you the same Kevin C. Higgins who previously testified on behalf of AECC in the interim phase of this proceeding?

A. Yes, I am.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on the Arizona Public Service Company ("APS") 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico rate case (2005),[10] the TEP rate review (2005),[11] the APS

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.

interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend Decision No. 62103 (2007),[14] and the TEP rate case (2008).[15]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in over ninety other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

A more detailed description of my qualifications is contained in Attachment KCH-1, attached to this testimony.

Overview and Conclusions

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses APS's request for a base rate increase of $448.2 million, which includes an increase of $183.9 million in base fuel cost, as proposed in the Company's Amended Application filed June 2, 2008. In my testimony, I recommend adjustments to the Company's proposal that I believe are necessary to ensure results that are just and reasonable.

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[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.
[13] Docket No. E-01345A-05-0816.

Relative to the wide scope of this general rate proceeding, my recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular revenue issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that APS's proposed attrition adjustment be rejected. In my opinion, APS's use of a Calendar Year 2010 timeframe for calculating the attrition adjustment is too speculative for setting rates in this proceeding. On a standalone basis, this adjustment would reduce the Company's proposed increase in base rates by $79.3 million.

(2) APS makes pro-forma adjustments that include a full year of depreciation expense for discrete investments at Palo Verde, Cholla, and Yucca that occurred in 2008 however, APS does not recognize any associated accumulated depreciation for these adjustments in calculating rate base. This overstates cost to customers. Therefore, I recommend adjusting rate base for the amount of the increase in accumulated depreciation. This adjustment would reduce the Company's proposed increase in base rates by $0.8 million.

(3) In my opinion, the most appropriate timeframe for consideration of APS's rate base is average-of-year 2009. This would exclude proposed rate base additions that are scheduled to occur after December 31 of that year. Using APS's

[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.

proposed rate of return, adoption of my proposed treatment of rate base, including associated increases in depreciation expense, would increase APS's proposed rate increase by $54.3 million, when viewed in isolation. This increase occurs because my rate base treatment recognizes 2009 plant in service that APS had included in its attrition adjustment, which I am recommending be rejected. Thus, my proposed treatment of 2009 rate base restores a significant portion of the cost recovery that is eliminated with rejection of the attrition adjustment.

(4) During the interim phase of this proceeding, APS indicated that it was undertaking to cut capital costs by $500 million over the period 2009 through 2011. These cuts have likely implications for APS rate base additions in 2009. I recommend a tentative adjustment to account for these cutbacks that reduces projected additions to plant in service for 2009 by 25 percent, exclusive of APS's pro-forma additions. This adjustment reduces APS's proposed revenue increase by $17.5 million.

(5) I recommend setting the base fuel rate using projected 2009 fuel and purchased power expense, as opposed to APS's proposal to use projected costs for 2010. In addition, forward price curves for natural gas and purchased power have come down considerably since APS filed its case. Based on my review of information provided by APS in its monthly PSA filings and in discovery, I propose a tentative $42.5 million reduction to APS's fuel and purchased power expense. This tentative adjustment is based on an estimated base fuel rate of 3.7327¢ per kWh for 2009.

(6) In its pro-forma derivation of revenue requirement, APS measures retail sales using end-of-period 2007 sales levels, normalized for weather. Consistent with my recommendation that rate base should be measured on an average-of-year 2009 basis, retail sales revenue should be measured using a weather-normalized sales projection for Calendar Year 2009. I adjust APS's retail sales revenue using APS's projected sales level for 2009 presented in the Company's workpapers. This higher level of sales also requires an adjustment for increased fuel and purchased power expense. The net effect is to reduce APS's requested revenue increase by $15.6 million.

Q. Please summarize the impact of your proposed adjustments to APS's revenue increase.

A. I am recommending the following adjustments to APS's proposed revenue increase (all amounts in $ millions):

Deny Attrition Adjustment	$(79.3)
Recognize accumulated depreciation for PV, Cholla, Yucca	$(0.8)
Use 2009 average-of-year rate base	$ 54.3
Cut back new plant in 2009	$(17.5)
Fuel and purchased power cost reduction	$(42.5)
Use 2009 retail sales, net of fuel cost	$(15.6)
Total	$(101.4)

1 **Test Period**

2 **Q. What is meant by the term "test period" as used in ratemaking?**

3 A. "Test period" refers to a discrete twelve-month period that is used as the
4 basis for setting utility rates in a general rate proceeding. The test period
5 revenues, expenses, and investment levels of the utility are identified and used for
6 calculating the change in revenue required to provide the utility a reasonable
7 opportunity to earn its allowed rate of return.

8 **Q. What test period is APS using in its application?**

9 A. In my opinion, APS's application does not provide a clear definition of its
10 test period. APS begins its analysis by presenting a Calendar Year 2007 test year
11 that sets out the Company's twelve-month operations and investment. These
12 results are then adjusted for ratemaking purposes, which is typical in most general
13 rate proceedings. However, in most ratemaking contexts, the test period analysis
14 that results from such adjustments can be readily described with reference to a
15 discrete time period, e.g., "2007 historical Test Year with known and measureable
16 changes through 12/31/08," or "2008 projected test period," etc.

17 APS's filing defies such a clear description. While the basis of the
18 Company's filing starts with 2007 actual revenues, expenses, and investment, the
19 filing incorporates various revenue, expense, and investment elements that are
20 projected for the years 2008, 2009, and 2010, but without adhering to a consistent
21 time frame for all adjustments. The issue is highlighted in Table KCH-1, below,
22 which identifies the time period applicable to various APS proposed adjustments:

Table KCH-1

Time Frame for Various APS-Proposed Adjustments

Adjustment	Time Frame for Valuation	Reference
Rate base	New plant through 9/30/09	Kearns, pp. 23-30
Employee count	March 2008 level	LaBenz, p. 20
Wages – non-union	March 2008 level	LaBenz, p. 20
Wages – union	March 2009 projection	LaBenz, p. 20
Employee benefits	Calendar Year 2008	LaBenz, p. 21
Property taxes	2009 rates on 12/31/07 values	LaBenz, p. 23
Fuel expense	Calendar Year 2010	Ewen, p. 21
Retail sales	December 2007 sales level	Ewen workpapers
Attrition	Through December 2010	Kearns, pp. 20, 31

As noted in the table above, APS's filing includes a requested adjustment for "attrition," through which APS seeks to recover in base rates the revenue deficiency the Company forecasts it will otherwise incur in 2010.

Q. What is your assessment of APS's approach to test period?

A. In my opinion, the multiple time frames applied to APS's test period analysis yields an analytical patchwork that is problematic for setting rates. This approach does not produce a consistent set of data applicable to a well-defined twelve-month test period, resulting in a host of mismatches between revenue, expenses, and rate base.

Further, it appears to me that with its proposed attrition adjustment, APS is actually seeking to set rates based on the equivalent of a Calendar Year 2010 projected test period. This intent is apparent in the testimony of APS witness Daniel A. Kearns, who states that "by measuring the attrition adjustment through the 2010 timeframe, the Company proposes to set revenue levels for calendar year 2010 that match its 2010 costs."[16] My understanding, however, is that the

[16] Supplemental direct testimony of Daniel A. Kearns, p. 20, lines 8-9.

Company is required by R14-2-103(p) to present its application using an historical period. APS appears to have responded to this requirement by applying selected pro-forma adjustments of varying vintages to the Calendar Year 2007 test year, but then caps off its filing with a top-down attrition adjustment that plays the role of a "catch all" for all other revenue, expense, and investment items through the end of 2010.

Q. Do you support the use of a test period that is equivalent to Calendar Year 2010 for setting rates in this proceeding?

A. No, I do not. In my opinion, the use of a Calendar Year 2010 timeframe is too speculative for setting rates in this proceeding. In general, if a projected period is used to set rates, I believe a period relatively close in time to the filing date is preferred to a period set more aggressively into the future. This preference is even more pronounced in the current economic climate of recession and the significant uncertainty about its depth and duration, as the current economic conditions impair the ability of parties to accurately predict prices and the level of economic activity in Arizona over the next several future years. As indicated in the interim phase of this proceeding, even APS's own investment plans are subject to considerable change. Any errors in a 2009 forecast will be built into the base from which a 2010 projection is made. Additional errors in the subsequent year's projections can have a compounding effect.

Q. How will your opinion on this point affect the recommendations you make in your testimony?

A. In the recommendations I offer below, I propose to exclude revenue, expense, and rate base items that are projected to occur after December 31, 2009. Even the use of 2009 projections is subject to considerable uncertainty. Yet, in consideration of the filing and hearing schedule for this proceeding, I believe that the end of 2009 represents a reasonable cut-off point for inclusion of revenue, expense, and rate base values for use in setting APS's rates in this case. In my opinion, this timeframe best balances the need to provide APS a reasonable opportunity to recover its costs, including return, while setting rates for customers that are just and reasonable.

<u>Attrition Adjustment</u>

Q. Please describe briefly APS's proposed attrition adjustment.

A. The Company's proposal for an attrition adjustment is presented in the supplemental direct testimony of Mr. Kearns. In Attachments DAK-1 and DAK-2, Mr. Kearns presents his projections of the major components of revenue and expense through 2010, along with his projection of APS rate base through that time. Mr. Kearns uses these projections to forecast a revenue deficiency that he predicts would occur in 2010, even if the Company received rate relief corresponding to all of its pro forma adjustments to the 2007 test year. The additional revenue needed to eliminate this projected 2010 deficiency constitutes the Company's requested attrition adjustment, which Mr. Kearns calculates to be $79.3 million. APS incorporates the attrition adjustment into its proposed base rate increase of $448.2 million.

1 **Q. What is your assessment of APS's proposed attrition adjustment?**

2 A. I recommend that the attrition adjustment be rejected. As I discussed
3 above, I believe the use of a Calendar Year 2010 test period is not appropriate for
4 setting rates in this proceeding. Further, the proposed attrition adjustment is based
5 on a high-level, "top-down" analysis of the Company's projected operating
6 income, without the detailed support normally associated with ratemaking
7 adjustments. As such, the analysis does not lend itself to the scrutiny necessary
8 for setting rates.

9 **Q. Do you have any other concerns with the proposed attrition adjustment?**

10 A. Yes. The attrition adjustment erroneously reverses the regulatory
11 disallowance of $10 million for West Phoenix Unit 4 required in previous
12 Commission decisions. The error occurs despite APS's recognition of the West
13 Phoenix regulatory disallowance in its pro-forma adjustments and is a byproduct
14 of the top-down nature of the attrition adjustment calculation..

15 The error appears in the attrition adjustment derivation shown in APS
16 Attachment DAK-2. Line 10 of the attachment identifies the major changes in
17 APS rate base projected for the three-year period December 31, 2007 through
18 December 31, 2010, which totals $1.044 billion. Line 11 of the attachment
19 subtracts from this total the rate base changes covered by APS's other pro forma
20 adjustments, which total $418 million. This latter figure is comprised of $428
21 million in new plant additions *minus* $10 million for the West Phoenix Unit 4
22 regulatory disallowance. Line 12 is depicted as the "remaining major changes in
23 ACC rate base not covered in rates" and is the difference between line 10 ($1.044

billion) and line 11 ($418 million), or $626 million. The attrition adjustment then attempts to recover costs associated with this $626 million in projected rate base. The problem is that the amount being subtracted (line 11) has been reduced by the amount of the West Phoenix disallowance ($10 million); thus, when line 11 it is subtracted from line 10, the resulting value of $626 million is too high by this $10 million, effectively reversing the West Phoenix regulatory disallowance. If the attrition adjustment is accepted by the Commission, then the rate base component should be reduced by the $10 million amount of the West Phoenix regulatory disallowance; that is, the remaining addition to rate base would be $616 million, not $626 million.

Q. Your opposition to the attrition adjustment derives, in part, from its inclusion of 2010 cost elements. Doesn't the attrition adjustment also include cost elements from 2009?

A. Yes, it does. I will address the portion of the attrition adjustment that is tied to increases in 2009 rate base in the next section of my testimony.

Q. What is the impact of your recommendation on the Company's proposed rate increase?

A. On a standalone basis, adoption of my recommendation to reject the attrition adjustment would reduce the Company's proposed increase in base rates by $79.3 million, which is shown in Attachment KCH-2. However, this impact is prior to consideration of 2009 rate base adjustments, which I discuss below.

1 **Adjustments to Rate Base and Associated Depreciation Expense**

2 **Q. What adjustments to its 2007 rate base does APS propose?**

3 A. APS proposes adjustments to its end-of-2007 rate base for: (1)
4 replacement of the Palo Verde Unit 3 Steam Generator; (2) addition of Cholla
5 Generating Station Environmental Capital Projects; (3) addition of Yucca Units 5
6 and 6; (4) 1,201 various plant additions projected to occur between January 1,
7 2008 and September 30, 2009; and (5) recognition of the regulatory disallowance
8 for West Phoenix Unit 4 required in previous Commission decisions.

9 In addition, as discussed above, APS proposes the equivalent of $626
10 million in incremental rate base through December 31, 2010 in addition to the
11 Company's pro-forma rate base adjustments. This incremental rate base forms the
12 basis of cost recovery under the Company's proposed attrition adjustment.

13 **Q. Do you have any recommended modifications to APS's proposed treatment**
14 **of rate base?**

15 A. Yes, I do. As I stated above, I believe the most appropriate timeframe for
16 consideration of APS's rate base is 2009. This would exclude proposed rate base
17 additions that are scheduled to occur after December 31 of that year. Further, the
18 rate base level should be calculated using an average-of-year (2009) basis, as
19 distinct from end-of-year. In my experience in many jurisdictions, setting rate
20 base using an average-of-year basis is the conventional practice, particularly when
21 a projected time period is used as the basis for setting rates.

22 **Q. What timeframe does APS use for its proposed rate base adjustments?**

A. As I discussed in the "Test Period" section of my testimony, APS does not adhere to a consistent timeframe. APS values its major pro-forma rate base additions for Palo Verde, Cholla, and Yucca (listed above) at the full value of the plant in service on the date it enters service, e.g., the replacement of the Palo Verde Unit 3 Steam Generator on January 19, 2008 is included in rate base at its full original cost on that date. In addition, APS proposes to recover a full year's worth of depreciation expense for each of the items the Company brings into rate base.

Q. Is there a problem with this?

A. Yes, there is a consistency problem. I do not object to plant that is in service in January 2008, such as the new Palo Verde Unit 3 Steam Generator, recovering a full year's worth of depreciation expense based if Calendar Year 2009 is used to determine rate base. But at the same time, plant in service for which the utility recovers a full year's worth of depreciation expense should not be in rate base for the full amount of its original cost, as its associated rate base should be reduced by the amount of accumulated depreciation corresponding to its in-service date and the test period being utilized. APS proposes to recover a full year's worth of depreciation expense for each of its pro-forma increases to plant in service, but provides no corresponding offsets to rate base for the amount of this depreciation. This approach overstates costs to customers.

Q. What level of depreciation expense should be applied to plant that comes on line after the close of APS's historical test period of December 31, 2007?

1 A. Consistent with my recommendation that rate base should be measured on
2 an average-of-year 2009 basis, depreciation expense for pro-forma rate base
3 adjustments should correspond to the depreciation expense that plant in service
4 would incur for Calendar Year 2009. This means that plant in service on
5 December 31, 2008 would incur a full year's worth of depreciation expense and
6 the depreciation expense for plant coming into service during 2009 should be pro-
7 rated to correspond to the portion of the year in which the plant is expected to be
8 in service.

9 **Q. What are the implications for accumulated depreciation as it applies to pro-**
10 **forma rate base adjustments?**

11 A. Consistent with my recommendation that rate base should be measured on
12 an average-of-year 2009 basis, accumulated depreciation for pro-forma rate base
13 adjustments should reflect average of year 2009 levels.

14 **Q. What adjustments are you proposing to APS's rate base?**

15 A. I modify the four APS rate base additions listed above (Palo Verde Unit 3,
16 Cholla, Yucca Units 5 and 6, and miscellaneous post-test-year plant additions) to
17 correspond to average of year 2009 values. These adjustments are presented in
18 Attachments KCH-3, KCH-4, KCH-5, and KCH-6, respectively.

19 **Q. How do you treat APS's rate base additions that are projected to occur in**
20 **2008 and 2009 but are excluded from APS's pro-forma adjustments?**

21 A. These projected rate base additions are excluded from APS's pro-forma
22 adjustments, but are included as part of the Company's proposed attrition
23 adjustment. I propose to treat these projected rate base additions in two steps. In

the first step, I accept the full amount of APS's projection of new plant in service and adjust it to an average-of-year 2009 value. This calculation is also presented in Attachment KCH-6, page 1 (in columns referencing APS Attrition Adjustment). In the second step, I adjust the APS projection of new plant in service for 2009 downward in anticipation of revisions to APS's capital investment plans, which were discussed during the interim phase of this proceeding. I then adjust this amount to an average-of-year 2009 value. This adjustment is also presented in Attachment KCH-6, page 1.

The income adjustments associated with my proposed treatment of rate base are presented in Attachment KCH-6, page 2.

Q. Please explain further the justification for adjusting downward the APS projection of new plant in service for 2009 downward.

A. During the interim phase of this proceeding, APS indicated that it was undertaking to cut capital costs by $500 million over the period 2009 through 2011. These cuts have likely implications for APS rate base additions in 2009. In discovery, AECC asked APS to provide any revisions to its rate base projections in its attrition adjustment that have been made since the filing of APS's revised case. APS declined to provide any revisions in response to AECC's discovery request, but indicated that the Company would update its forecasted changes to jurisdictional plant when it filed its rebuttal testimony.[17]

Since APS apparently does not intend to disclose the impact of its capital expenditure cutbacks on projected 2009 rate base until it files its rebuttal

[17] APS Response to AECC 3.6.b.

testimony, I have assumed that the cutbacks reduce projected additions to plant in service for 2009 by 25 percent, exclusive of APS's pro-forma additions (i.e., I reduce only the portion of 2009 rate base additions that are associated with APS's attrition adjustment). I consider this adjustment to be tentative pending APS's update of its projected rate base additions for 2009.

Q. What is the cumulative effect of your recommended adjustments to rate base relative to the pro-forma rate base proposed by APS?

A. This effect of my adjustments to rate base is shown in Attachment KCH-9, which summarizes the results of each of my adjustments. APS is proposing a pro-forma ACC rate base of $5.360 billion. My proposal for an average-of-year 2009 rate base, with adjustments, results in a rate base of $5.444 billion.

Q. What is the estimated impact of your recommended treatment of rate base on the Company's proposed rate increase?

A. Using APS's proposed rate of return, adoption of my proposed treatment of rate base, including associated increases in depreciation expense, would increase APS's revenue requirement by $36.8 million, when viewed in isolation. (This is shown in Attachment KCH-6, page 1.) This increase would be $17.5 million higher without my assumed cutback in new plant additions in 2009. The increase that occurs from this adjustment is attributable to the fact that my rate base treatment recognizes 2009 plant in service that APS had included in its attrition adjustment, which I am recommending be rejected. That is, my proposed treatment of 2009 rate base restores a significant portion of the cost recovery that is eliminated with rejection of the attrition adjustment. When viewed in tandem

with my recommendation to reject the attrition adjustment, it has a net impact of reducing APS's proposed base rate increase by $42.5 million.

I note also that adoption of my proposed treatment of 2009 rate base should be accompanied by recognition of projected 2009 sales levels in determining revenue requirement, which I discuss below. As 2009 rate base would be used for providing service to 2009 load, it would not be reasonable to pay for 2009 rate base using end-of-year 2007 sales levels.

Fuel and Purchased Power

Q. What has APS proposed with respect to fuel and purchased power expense?

A. APS's proposal for fuel and purchased power expense is presented in the supplemental direct testimony of Peter M. Ewen. APS is proposing to increase the base fuel rate from 3.25¢ per kWh established in Docket No. 69633 to 3.88¢ per kWh, based on the Company's projection for 2010 fuel costs. This increase constitutes $183.9 million of the Company's proposed $448.2 million base rate increase.

Q. What is your assessment of APS's proposed treatment of fuel and purchased power expense?

A. Consistent with my test period discussion, I recommend setting the base fuel rate using projected 2009 fuel and purchased power expense, as opposed to APS's proposal to use projected costs for 2010. Further, forward price curves for natural gas and purchased power have come down considerably since APS filed

its case. Therefore, I recommend that APS's fuel and purchased power expense be recalculated using updated pricing information applied to 2009.

Q. Will APS be filing any updated estimates of base fuel cost for 2009?

A. Yes. APS will be filing its 2009 base fuel cost projection as part of its annual PSA filing. However, the Company's filing has not been made at the time of the filing of my direct testimony.

Q. Do you have a tentative adjustment to APS's fuel and purchased power expense pending further information being made available?

A. Yes. Based on my review of information provided by APS in its monthly PSA filings and in discovery, I propose a tentative $42.5 million reduction to APS's fuel and purchased power expense. This tentative adjustment is based on an estimated base fuel rate of 3.7327¢ per kWh for 2009. I derived this rate using a base fuel rate of 3.7667¢ per kWh from APS's PSA report filed November 25, 2008,[18] adjusted downward by $10 million based on other information provided by APS in discovery.[19] I anticipate that the base fuel rate is likely to decline further due to more recent reductions in gas and power prices.

Q. By what means might you update your proposed tentative adjustment?

A. APS has stated that the Company intends to update its base fuel rate and fuel and purchased power expense in its rebuttal testimony. I may update my tentative adjustment in my surrebuttal testimony after review of APS's rebuttal filing and additional relevant information.

[18] Also summarized in APS Supplemental Response to Staff 25.10 (which contains a minor typo in the final line).
[19] APS Response to Staff 17.6.

1 **Q. What is the estimated impact of your tentative adjustment to fuel and**
2 **purchased power expense on the Company's proposed rate increase?**
3 A. The estimated impact is a $42.5 million reduction, which is shown in
4 Attachment KCH-7.
5
6 **Revenues from Sales**
7 **Q, How has APS treated revenues from retail sales in its calculation of revenue**
8 **requirement?**
9 A. In its pro-forma derivation of revenue requirement, APS measures retail
10 sales using end-of-period 2007 sales levels, normalized for weather. At the same
11 time, the Company's attrition adjustment incorporates a projection of increased
12 sales levels for 2008 through 2010.
13 **Q. What timeframe do you recommend for measuring retail sales revenue in**
14 **this proceeding?**
15 A. Consistent with my recommendation that rate base should be measured on
16 an average-of-year 2009 basis, retail sales revenue should be measured using a
17 weather-normalized sales projection for Calendar Year 2009. If rates are set to
18 recover costs associated with 2009 rate base, it is essential that cost recovery be
19 spread across the projected 2009 sales that will be served by this rate base. It
20 would not be reasonable to pay for 2009 rate base using end-of-year 2007 sales
21 levels.
22 In Attachment KCH-8, I adjust APS's retail sales revenue using APS's
23 projected sales level for 2009 presented in Mr. Ewen's workpapers. This higher

level of sales also requires an adjustment for increased fuel and purchased power expense, which is also shown on Attachment KCH-8. The net effect is to reduce APS's requested revenue increase by $15.6 million.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"Application of Oncor Electric Delivery Company LLC for Authority to Change Rates," Public Utility Commission of **Texas**, SOAH Docket No. 473-08-3681, PUC Docket No. 35717. Direct testimony submitted November 26, 2008.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Its Electric Security Plan; An Amendment to Its Corporate Separation Plan; and the Sale of Certain Generating Assets", Public Utilities Commission of **Ohio**, Case No. 08-917-EL-SSO; "In the Matter of the Application of Ohio Power Company for Approval of Its Electric Security Plan; and an Amendment to Its Corporate Separation Plan," Case No. 08-918-EL-SSO. Direct testimony submitted October 31, 2008. Cross examined November 25, 2008.

"Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00252. Direct testimony submitted October 28, 2008.

"Application of Kentucky Utilities Company for an Adjustment of Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00251. Direct testimony submitted October 28, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-08-10. Direct testimony submitted October 24, 2008. Rebuttal testimony submitted December 3, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 08-035-38. Direct testimony submitted October 7, 2008 (test period). Cross examined October 28, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan," Public Utility Commission of **Ohio**, Case No. 08-935-EL-SSO. Direct testimony submitted September 29, 2008. Deposed October 13, 2008. Cross examined October 21, 2008.

"In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes In Their Charges for Electric Service," State Corporation Commission of **Kansas**, Docket No. 08-WSEE-1041-RTS. Direct testimony submitted September 29, 2008. Cross Answer testimony submitted October 8, 2008.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2008-00046. Direct testimony submitted September 26, 2008.

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications with Reconciliation Mechanism and Tariffs for Generation Service," Public Utility Commission of **Ohio**, Case No. 08-936-EL-SSO. Direct testimony submitted September 9, 2008. Deposed September 16, 2008.

"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," **Arizona** Corporation Commission, Docket No. E-01345A-08-0172. Direct testimony submitted August 29, 2008 (interim rates). Cross examined September 16, 2008 (interim rates).

"Verified Joint Petition of Duke Energy Indiana, Inc., Indianapolis Power & Light Company, Northern Indiana Public Service Company and Vectren Energy Delivery of Indiana, Inc. for Approval, if and to the Extent Required, of Certain Changes in Operations That Are Likely To Result from the Midwest Independent System Operator, Inc.'s Implementation of Revisions to Its Open Access Transmission and Energy Markets Tariff to Establish a Co-Optimized, Competitive Market for Energy and Ancillary Services Market; and for Timely Recovery of Costs Associated with Joint Petitioners' Participation in Such Ancillary Services Market," **Indiana** Utility Regulatory Commission, Cause No. 43426. Direct testimony submitted August 6, 2008. Direct testimony in opposition to Settlement Agreement submitted November 12, 2008.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority," **Michigan** Public Service Commission, Case No. U-15244. Direct testimony submitted July 15, 2008. Rebuttal testimony submitted August 8, 2008.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-197. Direct testimony submitted July 9, 2008. Surrebuttal testimony submitted September 15, 2008.

"In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200, Cost-Based Supply Service," Public Utility Commission of **Oregon,** Docket No. UE-199. Reply testimony submitted June 23, 2008. Joint testimony in support of stipulation submitted September 4, 2008.

"2008 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-072300 and UG-072301. Response testimony submitted May 30, 2008. Cross-Answer testimony submitted July 3, 2008. Joint testimony in support of partial stipulations submitted July 3, 2008 (gas rate spread/rate design), August 12, 2008 (electric rate spread/rate design), and August 28, 2008 (revenue requirements). Cross examined September 3, 2008.

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, Et Seq., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code 8-1-2.5-1Et Seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with Its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs in Its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests," **Indiana** Utility Regulatory Commission, Cause No. 43374. Direct testimony submitted May 21, 2008.

"Cinergy Corp., Duke Energy Ohio, Inc., Cinergy Power Investments, Inc., Generating Facilities LLCs," **Federal Energy Regulatory Commission**, Docket No. EC-08-78-000. Affidavit filed May 14, 2008.

"Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs, Public Utility Commission of **Texas**, Docket No. 34800 [SOAH Docket No. 473-08-0334]. Direct testimony submitted April 11, 2008. Testimony withdrawn pursuant to stipulation.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates, Central Illinois Light Company d/b/a AmerenCILCO, Proposed General Increase in Gas Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589, 07-0590. Direct testimony submitted March 14, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Public Service Company of Colorado for Authority to Implement an Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Recovery and Incentives," **Colorado** Public Utilities Commission, Docket No. 07A-420E. Answer testimony submitted March 10, 2008. Cross examined April 25, 2008.

"An Investigation of the Energy and Regulatory Issues in Section 50 of Kentucky's 2007 Energy Act," **Kentucky** Public Service Commission, Administrative Case No. 2007-00477. Direct testimony submitted February 29, 2008. Supplemental direct testimony submitted April 1, 2008. Cross examined April 30, 2008.

In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations throughout the State of Arizona, **Arizona** Corporation Commission, Docket No. E-01933A-07-0402. Direct testimony submitted February 29, 2008 (revenue requirement), March 14, 2008 (rate design), and June 12, 2008 (settlement agreement). Cross examined July 14, 2008.

"Commonwealth Edison Company Proposed General Increase in Electric Rates," **Illinois** Commerce Commission, Docket No. 07-0566. Direct testimony submitted February 11, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Questar Gas Company to File a General Rate Case," **Utah** Public Service Commission, Docket No. 07-057-13. Direct testimony submitted January 28, 2008 (test period), March 31, 2008 (rate of return), April 21, 2008 (revenue requirement), and August 18, 2008 (cost of service, rate spread, rate design). Rebuttal testimony submitted September 22, 2008 (cost of service, rate spread, rate design). Surrebuttal testimony submitted May 12, 2008 (rate of return) and October 7, 2008 (cost of service, rate spread, rate design). Cross examined February 8, 2008 (test period), May 21, 2008 (rate of return), and October 15, 2008 (cost of service, rate spread, rate design).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," **Utah** Public Service Commission, Docket No. 07-035-93. Direct testimony submitted January 25, 2008 (test period), April 7, 2008 (revenue requirement), and July 21, 2008 (cost of service, rate design). Rebuttal testimony submitted September 3, 2008 (cost of service, rate design). Surrebuttal testimony submitted May 23, 2008 (revenue requirement) and September 24, 2008 (cost of service, rate design). Cross examined February 7, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals," Public Utilities Commission of **Ohio**, Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, and 07-554-EL-UNC. Direct testimony submitted January 10, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately $36.1 Million per Year, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff," **Wyoming** Public Service Commission, Docket No. 20000-277-ER-07. Direct testimony submitted January 7, 2008. Cross examined March 6, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service to Electric Customers in the State of Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-07-8. Direct testimony submitted December 10, 2007. Cross examined January 23, 2008.

"In The Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution Of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-15245. Direct testimony submitted November 6, 2007. Rebuttal testimony submitted November 20, 2007.

"In the Matter of Montana-Dakota Utilities Co., Application for Authority to Establish Increased Rates for Electric Service," **Montana** Public Service Commission, Docket No. D2007.7.79. Direct testimony submitted October 24, 2007.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 334," **New Mexico** Public Regulation Commission, Case No. 07-0077-UT. Direct testimony submitted October 22, 2007. Rebuttal testimony submitted November 19, 2007. Cross examined December 12, 2007.

"In The Matter of Georgia Power Company's 2007 Rate Case," **Georgia** Public Service Commission, Docket No. 25060-U. Direct testimony submitted October 22, 2007. Cross examined November 7, 2007.

"In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the MidAmerican Energy Holdings Company Transaction," **Utah** Public Service Commission, Docket No. 07-035-04; "In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order To Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization," Docket No. 06-035-163; "In the Matter of the Application of Rocky Mountain Power for an Accounting Order for Costs related to the Flooding of the Powerdale Hydro Facility," Docket No. 07-035-14. Direct testimony submitted September 10, 2007. Surrebuttal testimony submitted October 22, 2007. Cross examined October 30, 2007.

"In the Matter of General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.," **Kentucky** Public Service Commission, Case No. 2006-00472. Direct testimony submitted July 6, 2007. Supplemental direct testimony submitted March 14, 2008.

"In the Matter of the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Service," **Arizona** Corporation Commission, Docket No. E-03964A-06-0168. Direct testimony submitted July 3, 2007. Rebuttal testimony submitted January 17, 2008.

"Application of Public Service Company of Oklahoma for a Determination that Additional Electric Generating Capacity Will Be Used and Useful," **Oklahoma** Corporation Commission, Cause No. PUD 200500516; "Application of Public Service Company of Oklahoma for a Determination that Additional Baseload Electric Generating Capacity Will Be Used and Useful," Cause No. PUD 200600030; "In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Granting Pre-Approval to Construct Red Rock Generating Facility and Authorizing a Recovery Rider," Cause No. PUD200700012. Responsive testimony submitted May 21, 2007. Cross examined July 26, 2007.

"Application of Nevada Power Company for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto," Public Utilities Commission of **Nevada**, Docket No. 06-11022. Direct testimony submitted March 14, 2007 (Phase III – revenue requirements) and March 19, 2007 (Phase IV – rate design). Cross examined April 10, 2007 (Phase III – revenue requirements) and April 16, 2007 (Phase IV – rate design).

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission, Docket No. 06-101-U. Direct testimony submitted February 5, 2007. Surrebuttal testimony submitted March 26, 2007.

"Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Rule 42T Application to Increase Electric Rates and Charges," Public Service Commission of **West Virginia**, Case No. 06-0960-E-42T; "Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Information Required for Change of Depreciation Rates Pursuant to Rule 20," Case No. 06-1426-E-D. Direct and rebuttal testimony submitted January 22, 2007.

"In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Missouri Service Areas," **Missouri** Public Service Commission, Case No. ER-2007-0004. Direct testimony submitted January 18, 2007 (revenue requirements) and January 25, 2007 (revenue apportionment). Supplemental direct testimony submitted February 27, 2007.

"In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103, **Arizona** Corporation Commission, Docket No. E-01933A-05-0650. Direct testimony submitted January 8, 2007. Surrebuttal testimony filed February 8, 2007. Cross examined March 8, 2007.

"In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area," **Missouri** Public Service Commission, Case No. ER-2007-0002. Direct testimony submitted December 15, 2006 (revenue requirements) and December 29, 2006 (fuel adjustment clause/cost-of-service/rate design). Rebuttal testimony submitted February 5, 2007 (cost-of-service). Surrebuttal testimony submitted February 27, 2007. Cross examined March 21, 2007.

"In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates," **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission," Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (revenue requirements) and September 1, 2006 (cost-of-service/rate design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric," **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**,

Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006. Rebuttal testimony submitted August 8, 2007. Cross examined September 19, 2007.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct and rebuttal testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish

Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"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, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost

Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility

Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery,"

Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01; "In the Matter of the Application of Rocky Mountain Power for an Order Approving an Amendment to Its Power Purchase Agreement with Sunnyside Cogeneration Associates," Docket Nos. 05-035-46, and 07-035-99. Direct testimony submitted July 8, 1996. Oral testimony provided March 18, 2008.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 2000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318.

Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Wyoming Load Growth Collaborative, March 2008 to present.

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to December 1999. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

AECC
Removal APS' Proposed Attrition Adjustment
Total Company
(Thousands of Dollars)

Proforma Adjustment: Remove APS Attrition

Line No.	Description	APS Total Company Amount	AECC Total Company Amount	AECC Adjustment
1.	**Revenues**			
2.	Other Electric Revenue	$ -	$ -	$ -
3.	**Other Operating Expenses**			
4.	Operations Excluding Fuel Expense	79,278	-	(79,278)
5.	Depreciation and Amortization	-	-	-
6.	Other Taxes	-	-	-
7.	Total Expenses	79,278	-	(79,278)
8.	**Operating Income (before income tax)**	**$ (79,278)**	**$ -**	**$ 79,278**
9.	Interest Expense	-	-	-
10.	Taxable Income	(79,278)	-	79,278
11.	Current Income Tax Rate - 39.36%	(31,204)	-	31,204
12.	**Operating Income After Tax**	**$ (48,074)**	**$ -**	**$ 48,074**
13.	**Gross Revenue Conversion Factor**			**1.6491**
14.	**Estimated Revenue Requirement Impact**			**$ (79,279)**

AECC Rate Base Pro Forma Adjustment
for Palo Verde Unit 3 Steam Generator and Low Pressure Turbine Rotor Replacment
to Reflect the Average Rate Base Amount for 2009
(Dollars in Thousands)

Proforma Adjustment:

Palo Verde Unit 3 Adjustment for Avg Rate Base
Adjustment to Test Year rate base (including accumulated depreciation) to include the replacement of the Palo Verde Unit 3 Steam Generators averaged for 2009 rate base.

Line No.	Description	APS Palo Verde Unit 3 SGR and LPTR Replacement	AECC Palo Verde Unit 3 SGR and LPTR Replacement	AECC Adjustment Difference
1.	Gross Utility Plant in Service	$ 49,135	$ 49,135	$ -
2.	Less: Accumulated Depreciation & Amort.	(44,725)	(41,632)	3,093
3.	Net Utility Plant in Service	93,860	90,767	(3,093)
4.	Less: Total Deductions			
5.	Plus: Total Additions			
6.	**Total Rate Base**	**$ 93,860**	**$ 90,767**	**$ (3,093)**
7.	**ACC Jurisdictional Amount**			**$ (3,038)**
8.	**APS Requested Rate of Return**			**8.86%**
9.	**Required Operating Income**			**$ (269)**
10.	**Gross Revenue Conversion Factor**			**1.6491**
11.	**Estimated Revenue Requirement Impact**			**$ (444)**

AECC
Rate Base Pro Forma Adjustments
Cholla Construction Projects
for Average 2009 Rate Base
(Dollars in Thousands)

Proforma Adjustment:

Cholla Environmental Projects Adjustment for Avg Rate Base
Adjustment to Test Year rate base (including accumulated deprecreciation) to include significant environmental and other Cholla construction projects for average 2009 rate base

Line No.	Description	APS Cholla Construction Projects	AECC Cholla Construction Projects	AECC Adjustment
1.	Gross Utility Plant in Service	$ 15,213	$ 15,213	$ -
2.	Less: Accumulated Depreciation & Amort.	(676)	(294)	382
3.	Net Utility Plant in Service	15,889	15,507	(382)
4.	Less: Total Deductions	-	-	-
5.	Plus: Total Additions			
6.	**Total Rate Base**	**$ 15,889**	**$ 15,507**	**$ (382)**
7.	**ACC Jurisdictional Amount**			**$ (376)**
8.	**APS Requested Rate of Return**			**8.86%**
9.	**Required Operating Income**			**$ (33)**
10.	**Gross Revenue Conversion Factor**			**1.6491**
11.	**Estimated Revenue Requirement Impact**			**$ (55)**

AECC YUCCA 5 AND 6
Rate Base Pro Forma Adjustments
Average 2009 Rate Base
(Dollars in Thousands)

Proforma Adjustment:

Yucca Units 5 and 6 Adjustment for Avg Rate Base
Adjustment to Test Year rate base (including accumulated depreciation) to include two CT generation units being built to serve Yuma for average 2009 rate base.

Line No.	Description	APS Yucca 5-6 Construction Projects ($000) Total Co.	AECC Yucca 5-6 Construction Projects ($000) Total Co.	AECC Adjustment Difference Total Co.
1.	Gross Utility Plant in Service	$ 77,123	$ 77,123	-
2.	Less: Accumulated Depreciation & Amort.	-	2,185	2,185
3.	Net Utility Plant in Service	77,123	74,939	(2,185)
4.	Less: Total Deductions	-	-	-
5.	Plus: Total Additions			-
6.	**Total Rate Base**	**$ 77,123**	**$ 74,939**	**$ (2,185)**
7.	**ACC Jurisdictional Amount**			**$ (2,146)**
8.	**APS Requested Rate of Return**			**8.86%**
9.	**Required Operating Income**			**$ (190)**
10.	**Gross Revenue Conversion Factor**			**1.6491**
11.	**Estimated Revenue Requirement Impact**			**$ (314)**

AECC
Rate Base Pro forma Adjustments
Twelve Months Ending December 31, 2009
(Dollars in Thousands)

Proforma Adjustment:

AECC Pro Forma Rate Base Adjustments - 2007 CWIP, Attrition Portion, and Capital Adjustment
Adjustment to Test Year rate base (including accumulated depreciation) to reflect average 2009 rate base for 2007 CWIP, 2009 rate base attrition, and an adjustment to 2009 capital projects expenditures.

		2007 APS CWIP Portion			2009 @ 100%	2009 w/ 25% Reduction	2009 w/ 25% Reduction
					APS Attrition Portion		
Line No.	Description	APS Post Test Year Plant Additions	AECC Post Test Year Plant Additions	AECC Adjustment	AECC Adjustment	AECC	AECC Adjustment
1.	Gross Utility Plant in Service	$ 251,258	$ 230,918	$ (20,340)	$ 919,630	$ 809,038	$ (110,592)
2.	Less: Accumulated Depreciation & Amort. - Existing				602,716	602,716	-
3.	Less: Accumulated Depreciation & Amort. - New	-	11,054	11,054	21,574	20,188	(1,387)
4.	Net Utility Plant in Service	251,258	219,863	(31,395)	295,339	186,134	(109,205)
5	Less: Total Deductions	-	-	-	62,609	62,609	-
6.	Plus: Total Additions	-	-	-	-	-	-
7.	**Total Rate Base**	**$ 251,258**	**$ 219,863**	**$ (31,395)**	**$ 232,730**	**$ 123,525**	**$ (109,205)**
8.	**ACC Jurisdictional Amount**			**$ (30,588)**	**$ 226,750**		**$ (106,399)**
9.	**APS Requested Rate of Return**			**8.86%**	**8.86%**		**8.86%**
10.	**Required Operating Income**			**$ (2,710)**	**$ 20,090**		**$ (9,427)**
11.	**Gross Revenue Conversion Factor**			**1.6491**	**1.6491**		**1.6491**
12.	**Estimated Revenue Requirement Impact from Rate Base**			**$ (4,469)**	**$ 33,131**		**$ (15,546)**
13.	**Estimated Revenue Requirement Impact from Income Statement**			**$ (474)**	**$ 26,116**		**$ (1,919)**
14.	**Estimated Revenue Requirement Impact - Rate Base + Income**			**$ (4,943)**	**$ 59,246**		**$ (17,465)**
15.	**Estimated Revenue Requirement Impact - Total**						**$ 36,838**

AECC
Income Statement Pro forma Adjustments
Twelve Months Ending December 31, 2007
(Dollars in Thousands)

Proforma Adjustment:

AECC Pro Forma Income Statement Adjustments - 2007 CWIP, Attrition Portion, and Capital Adjustment
Adjustment to Test Year income statement to reflect 2009 expensese for 2007 CWIP, 2009 rate base attrition, and an adjustment to 2009 capital projects expenditures.

		2007 APS CWIP Portion			APS Attrition Portion		
					2009 @ 100%	2009 w/ 25% Reduction	2009 w/ 25% Reduction
		APS	AECC	AECC	AECC	AECC	AECC
Line No.	Description	Post Test Year Plant Additions	Post Test Year Plant Additions	Adjustment	Adjustment		Adjustment
1.	Electric Operating Revenues	-	-	-	-	-	-
2.	Fuel Expense	-	-	-	-	-	-
3.	Oper Rev Less Fuel	-	-	-	-	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expenses	-	-	-	-	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	-	-	-	-	-	-
7.	Depreciation	14,134	13,110	(1,024)	30,837	26,975	(3,863)
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	3,214	3,214	-	-	-	-
11.	Total	17,348		(1,024)	30,837	26,975	(3,863)
12.	Operating Income	(17,348)	-	1,024	(30,837)	(26,975)	3,863
13.	Net Deductions	-	-	-	-	-	-
14.	Interest Expense	6,699	5,870	(829)	6,214	3,298	(2,916)
15.	Taxable Income	(24,047)	(5,870)	1,853	(37,051)	(30,273)	6,778
16.	Current Income Tax Rate - 39.36%	(9,465)	(2,311)	729	(14,583)	(11,915)	2,668
17.	Deferred Tax	-	-	-	-	-	-
18.	**Net Income**	**(7,883)**	**2,311**	**295**	**(16,254)**	**(15,059)**	**1,195**
19.	**ACC Jurisdictional Amount**			**$ 287**	**$ (15,836)**		**$ 1,164**
20.	**Gross Revenue Conversion Factor**			**1.6491**	**1.6491**		**1.6491**
21.	**Estimated Revenue Requirement Impact**			**$ (474)**	**$ 26,116**		**$ (1,919)**

AECC
Base Fuel and Purchased Power Adjustment
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **2007 BASE FUEL AND PURCHASED POWER**
Adjustment to APS Test Year Operations to Reduce 2010 Base Fuel and
Purchased Power ¢/kWh Costs to 2009 Base Fuel and Purchased Power Costs at Adjusted 2007 Consumption

Line No.	Description	APS (Based on 2010)	Amount	AECC (Based on 2009)	Amount	AECC Adjustment
1.	**ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)**					
2.	Normalized Fuel and Purchased Power Costs (¢/kWh)	3.8783		3.7327		
3.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.4346		3.4346		
4.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	0.4437		0.2981		
5.	**ADJUSTED TEST YEAR RETAIL SALES (MWh)**					
6.	Test Year Retail Sales (MWh)	29,171,321		29,171,321		
7.	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh)					
8.	To Adjust to Normal Weather	(445,396)		(445,396)		
9.	To Annualize to December 31, 2007 Customer Level	494,127		494,127		
10.	Adjusted 2007 Retail Sales (MWh)	29,220,052		29,220,052		
11.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 4 x Line 10)		$ 129,649		$ 87,119	$ (42,530)
12.	**Operating Income (before income tax)**		**$ (129,649)**		**$ (87,119)**	**$ 42,530**
13.	Current Income Tax Rate - 39.36%		(51,030)		(34,290)	16,740
14.	**Operating Income After Tax**		**$ (78,619)**		**$ (52,829)**	**$ 25,790**
15.	**Gross Revenue Conversion Factor**					**1.6491**
16.	**Estimated Revenue Requirement Impact**					**$ (42,530)**

AECC
2009 Sales Growth Adjustment
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: 2009 Sales Growth
AECC Adjustment to APS Test Year Operations to Adjust Revenue and Fuel and Purchased Power Costs to 2009 Consumption.

Line No.	Description	AECC (Based on 2009)	Amount
1.	**REVENUES**		
2.	Operating Revenue		27,972
3.	Pro Forma Additional 2009 Retail Consumption (MWh)	330,298	
4.	**ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)**		
5.	Normalized Fuel and Purchased Power Costs (¢/kWh)	3.7327	
6.			
7.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	3.7327	
8.	**ADJUSTED TEST YEAR RETAIL SALES (MWh)**		
9.	Adjusted Test Year Retail Sales (MWh)	29,220,052	
10.	Pro Forma Adjustments to Adjusted Test Year Retail Sales (MWh)		
11.	To Adjust to 2009 Consumption (MWh)	330,298	
12.	Adjusted 2009 Retail Sales (MWh)	29,550,350	
13.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 7 x Line 11)		$ 12,329
14.	**Operating Income (before income tax)**		**$ 15,643**
15.	Current Income Tax Rate - 39.36%		6,157
16.	**Operating Income After Tax**		**$ 9,486**
17.	**Gross Revenue Conversion Factor**		**1.6491**
18.	**Estimated Revenue Requirement Impact**		**$ (15,643)**

AECC
Computation of Increase in Gross Revenue Requirements
ACC Jurisdiction
Estimated 2009 Test Year
(Thousands of Dollars)

Line No.	Description	Original Cost
1	Rate Base - AECC Adjusted	$ 5,444,168
2	Adjusted Operating Income	272,077
3	Current Rate of Return	5.00%
4	Required Operating Income	482,353
5	Requested Rate of Return	8.86%
6	Adjusted Operating Income Deficiency	210,276
7	Gross Revenue Conversion Factor	1.6491
8	AECC Adjused Increase in Base Revenue Requirement	$ 346,767
9	APS Requested Increase in Base Revenue Requirement	448,194
10	AECC Revenue Adjustment from APS Request	$ (101,427)

AECC
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
to Reflect 2009 Average Rate Base Balances
(Thousands of Dollars)

Line No.	Description	APS Adjusted @ End of 12/31/2007 Total Co.	APS Adjusted @ End of 12/31/2007 ACC	Palo Verde Unit 3 Adjustment for Avg Rate Base Total Co.	Palo Verde Unit 3 Adjustment for Avg Rate Base ACC	Cholla Environmental Projects Adjustment for Avg Rate Base Total Co.	Cholla Environmental Projects Adjustment for Avg Rate Base ACC	Yucca Units 5 and 6 Adjustment for Avg Rate Base Total Co.	Yucca Units 5 and 6 Adjustment for Avg Rate Base ACC
1	Gross Utility Plant in Service	$ 12,304,621	$10,706,428	$ -	$ -	$ -	$ -	$ -	$ -
2	Less: Accumulated Depreciation and Amortizat	4,589,422	4,047,659	3,093	3,038	382	376	2,185	2,146
3	Net Utility Plant in Service	7,715,199	6,658,769	(3,093)	(3,038)	(382)	(376)	(2,185)	(2,146)
4	Less: Total Deductions	2,508,598	2,276,040	0	0	0	0	0	0
5	Plus: Total Additions	1,029,265	977,235	0	0	0	0	0	0
6	Total Rate Base	$ 6,235,866	$ 5,359,964	$ (3,093)	$ (3,038)	$ (382)	$ (376)	$ (2,185)	$ (2,146)

AECC
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
to Reflect 2009 Average Rate Base Balances
(Thousands of Dollars)

Line No.	Description	2007 CWIP Portion Pro Forma Rate Base Adjustment for Avg Rate Base Total Co.	2007 CWIP Portion Pro Forma Rate Base Adjustment for Avg Rate Base ACC	Attrition Portion Pro Forma Rate Base Adjustment for Avg Rate Base Total Co.	Attrition Portion Pro Forma Rate Base Adjustment for Avg Rate Base ACC	Capital Adjustment Pro Forma Rate Base Adjustment for Avg Rate Base Total Co.	Capital Adjustment Pro Forma Rate Base Adjustment for Avg Rate Base ACC	AECC Adjusted @ 2009 Avg Rate Base Total Co.	AECC Adjusted @ 2009 Avg Rate Base ACC
1	Gross Utility Plant in Service	$ (20,340)	$ (19,817)	$ 919,630	$ 896,000	$ (110,592)	$ (107,750)	$13,093,319	$11,474,861
2	Less: Accumulated Depreciation and Amortizati	11,054	10,770	624,291	608,250	(1,387)	(1,351)	5,229,040	4,670,888
3	Net Utility Plant in Service	(31,395)	(30,588)	295,339	287,750	(109,205)	(106,399)	7,864,278	6,803,973
4	Less: Total Deductions	0	0	62,609	61,000	0	0	2,571,207	2,337,040
5	Plus: Total Additions	0	0	0	0	0	0	1,029,265	977,235
6	Total Rate Base	$ (31,395)	$ (30,588)	$ 232,730	$ 226,750	$ (109,205)	$ (106,399)	$ 6,322,337	$ 5,444,168

AECC Income Statement
Adjusted to Reflect 2009 Test Year

Line No.	Description	APS Proforma Total Company	APS Proforma ACC Jurisdiction	Remove Attrition Total Company	Remove Attrition ACC Jurisdiction	2007 CWIP Portion Pro Forma Rate Base Total Company	2007 CWIP Portion Pro Forma Rate Base ACC Jurisdiction	Attrition Portion Pro Forma Rate Base Total Company	Attrition Portion Pro Forma Rate Base ACC Jurisdiction
	Electric Operating Revenues								
1	Revenues from Base Rates	$ 2,690,150	$ 2,637,447						
2	Revenues from Surcharges	0	0						
3	Other Eelctric Revenues	122,862	94,461						
4	Total	2,813,012	2,731,908	0	0	0	0	0	0
	Operating Expenses:								
5	Electric Fuel and Purchased Power	1,232,888	1,200,220						
6	Operations and Maintenance Excluding Fuel Expense	771,228	827,598	(79,278)	(79,278)				
7	Depreciation and Amortization	384,796	345,176			(1,024)	(998)	30,837	30,045
8	Income Taxes	36,196	28,234	31,204	31,204	729	711	(14,583)	(14,209)
9	Other Taxes	146,931	127,568						
10	Total	2,572,039	2,528,796	(48,074)	(48,074)	(295)	(287)	16,254	15,836
11	Operating Income	240,973	203,112	48,074	48,074	295	287	(16,254)	(15,836)
	Other Income (Deductions)								
12	Income Taxes	4,578	0						
13	Allowance for Funds Used During Construction	21,195	0						
14	Other Income (Deductions)	16,727	0						
15	Other Expenses	(21,630)	0						
16	Total	20,870	0	0	0	0	0	0	0
17	Income Before Interest Deductions	261,843	203,112	48,074	48,074	295	287	(16,254)	(15,836)
	Interest Deductions:								
18	Interest on Long -Term Debt	161,030	0						
19	Interst on Short Term Borrowings	9,564	0						
20	Debt Discount, Premium and Expense	4,639	0						
21	Allowance for Borrowed Funds Used During Constructi	(12,308)	0						
22	Total	162,925	0	0	0	0	0	0	0
23	Net Income	98,918	203,112	48,074	48,074	295	287	(16,254)	(15,836)

AECC Income Statement
Adjusted to Reflect 2009 Test Year

Line No.	Description	Capital Adjustment Pro Forma Rate Base Total Company	Capital Adjustment Pro Forma Rate Base ACC Jurisdiction	2007 ase Fuel & Purchased Pow Total Company	2007 ase Fuel & Purchased Pow ACC Jurisdiction	2009 Pro Forma Sales Growth Total Company	2009 Pro Forma Sales Growth ACC Jurisdiction	AECC Proforma Total Company	AECC Proforma ACC Jurisdiction
	Electric Operating Revenues								
1	Revenues from Base Rates					$ 27,972	$ 27,972	$ 2,718,122	$ 2,665,419
2	Revenues from Surcharges							0	0
3	Other Eelctric Revenues							122,862	94,461
4	Total	0	0	0	0	27,972	27,972	2,840,984	2,759,880
	Operating Expenses:								
5	Electric Fuel and Purchased Power			(42,530)	(42,530)	12,329	12,329	1,202,687	1,170,019
6	Operations and Maintenance Excluding Fuel Expense							691,950	748,320
7	Depreciation and Amortization	(3,863)	(3,763)					410,746	370,460
8	Income Taxes	2,668	2,599	16,740	16,740	6,157	6,157	79,111	71,436
9	Other Taxes							146,931	127,568
10	Total	(1,195)	(1,164)	(25,790)	(25,790)	18,486	18,486	2,531,425	2,487,803
11	Operating Income	1,195	1,164	25,790	25,790	9,486	9,486	309,559	272,077
	Other Income (Deductions)								
12	Income Taxes							4,578	0
13	Allowance for Funds Used During Construction							21,195	0
14	Other Income (Deductions)							16,727	0
15	Other Expenses							(21,630)	0
16	Total	0	0	0	0	0	0	20,870	0
17	Income Before Interest Deductions	1,195	1,164	25,790	25,790	9,486	9,486	330,429	272,077
	Interest Deductions:								
18	Interest on Long -Term Debt							161,030	0
19	Interst on Short Term Borrowings							9,564	0
20	Debt Discount, Premium and Expense							4,639	0
21	Allowance for Borrowed Funds Used During Construction							(12,308)	0
22	Total	0	0	0	0	0	0	162,925	0
23	Net Income	1,195	1,164	25,790	25,790	9,486	9,486	167,504	272,077

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
AECC-4
ADMITTED

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-08-0172**

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Rate Design / Cost of Service

January 9, 2009

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ATTACHMENTS
KCH-10.....Summary of APS Cost of Service Results
KCH-11.....Summary of APS Rate Spread Impacts
KCH-12.....AECC Recommended Rate Spread at APS Requested Revenue Increase
KCH-13.....AECC Recommended Rate Spread at $100 Million Revenue Reduction

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Are you the same Kevin C. Higgins who previously testified on behalf of AECC in the interim and revenue requirement phases of this proceeding?

A. Yes, I am. My qualifications were presented in my direct testimony filed in the revenue requirement phase of this case, with additional detail in Attachment KCH-1, attached to that testimony.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

Overview and Conclusions

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses APS's proposed rate spread, rate design, and cost of service analysis.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that APS's cost of service study be adopted by the Commission. The Average and Excess Demand method employed by APS to allocate production plant costs fully meets the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. Further, APS's allocation of energy costs based on customer class hourly load shapes and their relationship to hourly energy prices is a significant improvement over the method that APS had used for allocating energy costs in previous cases. The updated approach better aligns cost responsibility with cost causation, improves fairness, and encourages efficiency in resource utilization through better price signals.

(2) In my opinion, APS's proposed rate spread does not move far enough in the direction of cost of service. I propose a rate spread approach that moves further in the direction of aligning rates with cost, while adhering to the principle of gradualism and providing continued rate mitigation for the Residential class. My proposal is summarized in the following five steps:

(a) Set Residential rates midway between system average percentage base rate increase and the percentage increase necessary to bring Residential base rates to cost-of-service.

(b) Move rates for Rate 20 and Street Lighting closer to cost, but cap the base rate increase for these classes at 5 percentage points above the system average base rate increase.

(c) Set Rates E-34 and E-35 (collectively) equal to cost-of-service, with Rate E-34 receiving a percentage increase that is 1.0 percentage point lower than Rate E-35.

(d) Set the percentage increase for the new E-32-XS class equal to cost of service.

(e) Set the percentage increase for all remaining rate schedules (e.g., remaining Rate E-32 schedules, E-32-TOU, Water Pumping, and Dusk-to-Dawn) equal to the respective cost-of-service for each, plus the same percentage point increase necessary to fund the mitigation for Residential customers and the customer classes subject to the 5 percent cap.

(3) If the Company's requested rate increase is reduced by the Commission, I recommend that the revenue apportionment produced by the rate spread shown in Table KCH-4 in my testimony should be used as the basis for spreading the smaller revenue change.

(4) APS is proposing a 188 percent increase in the Delivery Charge for transmission voltage service for Rate E-35. This would result in a much higher Delivery Charge to a transmission voltage customer on Rate E-35 – where the customer pays energy charges that vary with time-of-day – compared to Rate E-34 – where the customer would pay a flat energy charge. I see no merit in introducing such a discrepancy, and recommend that the dramatic increase proposed by APS for the Delivery Charge for Rate E-35 transmission voltage service be rejected. Instead, the Delivery Charge differential between primary and transmission voltage for Rate E-35 should be set at $3.764 per kW. This will

retain consistency between Rates E-34 and Rate E-35, as well with the current structure of E-35 rates.

(5) APS is proposing a change in the terms of Rates E-34 and E-35 that would require a customer to compensate the Company for the costs of additional third-party transmission service that is "required solely to provide service to a specific customer or customers." I recommend that this proposed change to the tariff be rejected. APS's retail transmission charges are simply a straight pass-through of rates in the Company's Open Access Transmission Tariff, which are approved by FERC. APS's attempt to introduce additional retail transmission charges outside the purview of its FERC-approved transmission rates would create an ad hoc pricing regime with limited oversight and the potential for double recovery. It would also create undue utility leverage in its dealings with its customers.

(6) I support the adoption of the CIAC "tax asset" portion of APS's proposed Impact Fee, as these costs are associated with the direct cost of providing facilities to serve the new customers' premises, which is a reasonable assignment of cost to cost causers. However, I recommend against adoption of the portion of the proposed Impact Fee that is intended to recover incremental system costs, as this takes on the character of "vintage pricing," which can result in unintended consequences, including the undue stifling of economic development.

(7) I recommend against APS's proposed changes to cost recovery for its Demand-Side Management ("DSM") programs. The proposed changes would divert DSM dollars away from DSM projects and instead direct them to the

Company's shareholders. In my view, this would not be the best use of revenue from customer-funded programs.

(8) APS is proposing to modify the Environmental Improvement Surcharge ("EIS"). Rather than treating the EIS funds used for eligible projects as Contributions in Aid of Construction ("CIAC"), as is required by the Commission, APS is proposing that the EIS provide a return on investment and recovery of expenses based on the projected cost of approved environmental expenditures. I recommend against adoption of the changes proposed by APS. With customers providing the up-front capital for the EIS projects, the Commission's previous determination that these funds should be booked as CIAC is reasonable. To the extent that this issue is considered anew, I recommend that the Commission consider eliminating the EIS in its entirety, as it is an application of single-issue ratemaking that is not necessary to ensure just and reasonable rates.

<u>Cost of Service</u>

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);

- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. If rates are unbundled by function, as they are in Arizona, then separating the utility's costs by function is important in determining which costs are generation-related, transmission-related, and distribution-related.

The classification of costs is critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes is important for determining revenue apportionment across customer classes, also called "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. For these reasons, the results of the class cost-of-service analysis should be given very strong weighting in guiding the proper revenue apportionment.

1 Q. **What approach has APS used for allocating generation plant costs between**
2 **APS retail customers and FERC-jurisdictional customers?**
3 A. As explained in the direct testimony of APS witness David Rumolo, APS
4 uses the 4-Coincident Peaks ("4-CP") method for allocating generation plant costs
5 between its state and federal jurisdictional loads. The 4-CP method allocates fixed
6 production costs based on the average of system peak demands in the four
7 summer months, which is when APS's production capacity requirements are
8 determined.
9 Q. **In your opinion, is the 4-CP method appropriate for allocating APS's**
10 **jurisdictional generation plant costs?**
11 A. Yes. APS's maximum system demands are driven by summer usage.
12 Given the characteristics of APS's system, the 4-CP method properly aligns the
13 allocation of the Company's fixed costs with cost causation. As noted by Mr.
14 Rumolo, the 4-CP method is used by APS in its cases before FERC.
15 Q. **Does APS also use the 4-CP method for allocating generation plant costs**
16 **across its retail customer classes in this case?**
17 A. No. Even though in past proceedings APS has used the 4-CP method for
18 allocating generation plant costs across its retail customer classes, in this case the
19 Company uses the Average and Excess Demand method for that purpose.
20 Q. **Does APS explain the basis for the change?**
21 A. Yes. Mr. Rumolo explains that the Company utilized the Average and
22 Excess Demand method in response to a directive from the Commission to
23 propose an energy-weighting method for allocating fixed production plant in this

case. This directive was issued on page 71 in Decision No. 69633 in Docket No. E-01345A-05-0816:

> We will order APS, in its next rate application, to propose an energy-weighting method that addresses the concerns raised in this case, and that will also consider the likely cost shifting that will be necessary as we determine the appropriate rate design in this case.

The Commission, in its discussion of this issue, had commented favorably on the use of the Average and Excess Demand method for this purpose:

> We agree with Staff that an energy-weighting method for allocating production plant is appropriate for APS. However, we are not convinced that the method recommended by Staff is the method that should be adopted. AECC's recommended Average and Excess Demand method would eliminate the criticism that the average demand is being counted twice. [Decision No. 69663, p. 70, line 27 – p. 71, line 2.]

Q. Do you agree that the Average and Excess Demand method allocates a portion of production plant cost on the basis of energy usage?

A. Yes, I do. The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods" and fully meets the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[2]

Q. How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?

[2] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's excess demand, where excess demand is measured as the difference between each class's individual peak demand[3] and its average demand. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

Q. Is the Average and Excess Demand method used in any neighboring jurisdictions?

A. Yes. This approach is utilized by the Salt River Project as well as by Public Service Company of Colorado.

Q. How does APS allocate energy costs across customer classes?

A. APS allocates energy costs based on customer class hourly load shapes and their relationship to hourly energy prices, which produces a weighted energy cost for each class. This approach is a great improvement over the method that had been used for allocating energy costs in previous cases, in which it made no difference whether a class's kilowatt-hours were concentrated in high-cost, summer on-peak periods, or lower-cost, off-peak periods: each kilowatt-hour was assigned exactly the same cost.

Q. Do you support APS's use of a weighted energy cost for each customer class based on the class's hourly load shape?

A. Yes. The use of a weighted energy cost for each class is consistent with a recommendation I made to the Commission in Docket No. E-01345A-05-0816.

[3] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

This approach better aligns cost responsibility with cost causation, improves fairness, and encourages efficiency in resource utilization through better price signals.

Q. What is your overall recommendation concerning APS's cost-of-service methodology in this proceeding?

A. For the reasons discussed above, I recommend that APS's approach be adopted.

Q. Did you conduct any cost-of-service analysis in addition to what APS has presented?

A. Yes. APS's cost-of-service analysis presents the revenue deficiency for each customer class at an equalized rate of return for base rates. While this is an important piece of information, the focus on base rates necessarily ignores each rate schedule's contribution to APS revenue recovery through the Power Supply Adjustment ("PSA") charge. That is, the APS analysis calculates each customer class's revenue deficiency by assuming the PSA charge is zero and, by extension, that APS fuel costs in excess of the base fuel rate are going un-recovered. While, strictly speaking, this assumption is correct insofar as base rates are concerned, I believe it is also useful to indentify each customer class's revenue deficiency after taking account of class contributions to revenue recovery through the PSA charge. Such an analysis does not undo the APS study, but simply provides more information to present a more complete picture.

In Attachment KCH-10, I present class returns and revenue deficiencies after taking account of PSA revenues. I present this information using (a) current PSA rates, as well as (b) the implied PSA rates in APS's cost-of-service analysis. The results of this analysis are summarized in Table KCH-2, below[4].

Table KCH-2

APS Cost-of-Service Results
Percentage rate change required to bring each class to cost-of-service at APS's proposed revenue requirement

Class	Base Rate Change	Rate Change Net of Current PSA Revenues	Rate Change Net of APS Projected PSA Revenues
Residential	21.74%	17.03%	14.93%
General Service	11.60%	6.52%	4.27%
E-20	54.32%	48.08%	45.29%
GS TOU	7.76%	2.15%	(0.29)%
E-32 (total)	10.64%	5.90%	3.80%
E-32XS	21.57%	17.67%	15.91%
E-32S	10.87%	6.61%	4.70%
E-32M	8.86%	3.93%	1.75%
E-32L	5.93%	0.60%	(1.74)%
E-34	13.19%	6.76%	3.97%
E-35	20.47%	12.62%	9.25%
Water Pumping	3.82%	(1.43)%	(3.73)%
Street Lighting	54.31%	49.86%	47.86%
Dusk-to-Dawn	14.15%	12.58%	11.85%
Total	16.99%	12.09%	9.91%

Q. Please explain the "Base Rate Change" column in Table KCH-2.

A. This column shows the percentage change in base rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding. The percentages in this column focus exclusively on changes in base rates; thus, the

information in this column ignores the fact that customers currently make a substantial contribution to fuel cost recovery through the PSA charge. In other words, part of the change in base rates being shown is the shifting of cost recovery out of the PSA charge into base rates.

Q. Please explain the "Rate Change Net of Current PSA Revenues" column in Table KCH-2.

A. This column shows the percentage change in rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding – after taking into consideration that customers are currently paying a PSA charge equal to 0.4 cents/kWh. That is, this column shows the required net increase in rates over and above what customers are currently paying in base rates and the PSA Adjustor.

Q. Please explain the "Rate Change Net of APS Projected PSA Revenues" column in Table KCH-2.

A. This column is similar to the previous column, except that instead of current PSA revenues, it is based on APS's projected PSA revenues that would otherwise prevail in 2010. I present this column to be consistent with information presented in APS's filing. For example, it is comparable to the "Net of PSA Impacts" column shown in APS Schedule H-2.

[4] This table is enumerated KCH-2 as Table KCH-1 is incorporated in my revenue requirement testimony.

Rate Spread

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread, or revenue apportionment, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. What has APS proposed with respect to rate spread?

A. APS's proposed rate spread is presented in APS Schedule H-2 and is restated in Table KCH-3, below, along with APS's cost-of-service results.

Table KCH-3

Comparison of APS Cost-of-Service Results to APS Proposed Rate Change

Class	Base Rate Change per APS COS	APS Proposed Base Rate Change	Difference Between Cost & Proposed Rate
Residential	21.74%	17.27%	(4.47)%
General Service	11.60%	16.74%	5.14%
E-20	54.32%	20.20%	(34.12)%
GS TOU	7.76%	16.71%	8.95%
E-32 (total)	10.64%	16.58%	5.94%
E-32XS	21.57%	18.67%	(2.90)%
E-32S	10.87%	16.58%	5.71%
E-32M	8.86%	16.22%	7.36%
E-32L	5.93%	15.74%	9.81%
E-34	13.19%	16.50%	3.31%
E-35	20.47%	18.69%	(1.78)%
Water Pumping	3.82%	12.30%	8.48%
Street Lighting	54.31%	19.41%	(34.90)%
Dusk-to-Dawn	14.15%	19.36%	5.21%
Total	16.99%	16.99%	0%

As shown in Table KCH-3, APS's cost-of-service analysis shows the Residential class as warranting a base rate increase of 21.74 percent (at the Company's proposed revenue requirement), but receiving a base rate increase of 17.27 percent. At the same time, General Service customers are shown as warranting a base rate increase of 11.6 percent (at the Company's proposed revenue requirement), but receiving a base rate increase of 16.74 percent. Whereas the rate increase warranted by these two major groupings of customers is separated by more than 10 percentage points, the base rate increased proposed by APS is within a single percentage point for the two groups.

Q. **Have you calculated APS's proposed rate increase net of PSA revenues consistent with the information in Attachment KCH-10?**

1 A. Yes. This information is presented in Attachment KCH-11.

2 **Q. What is your assessment of APS's rate spread proposal?**

3 A. It is apparent from APS's proposed rate spread that the Company is
4 proposing a very small step in the direction of cost of service, while perpetuating
5 a very sizable subsidy from General Service customers to Residential customers. I
6 calculate the proposed subsidy to be in excess of $60 million.

7 In my opinion, the Company's proposed rate spread does not move far
8 enough in the direction of cost of service. While the current economic climate is
9 difficult for all customer classes, the magnitude of the inter-class subsidization in
10 APS's proposal is an especially unreasonable burden to place upon the customers
11 in the General Service class.

12 **Q. Do you have an alternative rate spread recommendation?**

13 A. Yes. I propose an approach that moves further in the direction of cost-of-
14 service, while adhering to the principle of gradualism and providing continued
15 rate mitigation for the Residential class. My proposal is summarized in the
16 following five steps:

17 (1) Set Residential rates midway between system average percentage base
18 rate increase and the percentage increase necessary to bring Residential base rates
19 to cost-of-service.

20 (2) Move rates for Rate 20 and Street Lighting closer to cost, but cap the
21 base rate increase for these classes at 5 percentage points above the system
22 average base rate increase.

(3) Set Rates E-34 and E-35 (collectively) equal to cost-of-service, with Rate E-34 receiving a percentage increase that is 1.0 percentage point lower than Rate E-35.

(4) Set the percentage increase for the new E-32-XS class equal to cost of service. (This will place this class right below the 5 percent cap described above.)

(5) Set the percentage increase for all remaining rate schedules (e.g., remaining Rate E-32 schedules, E-32-TOU, Water Pumping, and Dusk-to-Dawn) equal to the respective cost-of-service for each, plus the same percentage point increase necessary to fund the mitigation for Residential customers and the customer classes subject to the 5 percent cap.

Q. What is the rate spread that obtains from your recommended approach at APS's proposed revenue requirement?

A. These results are presented in Attachment KCH-12, and summarized in Table KCH-4, below.

Table KCH-4

Comparison of AECC Rate Spread to APS Rate Spread
At APS's Proposed Revenue Requirement

Class	Base Rate Change per APS COS	APS Proposed Base Rate Change	AECC Proposed Base Rate Change
Residential	21.74%	17.27%	19.37%
General Service	11.60%	16.74%	14.52%
E-20	54.32%	20.20%	21.99%
GS TOU	7.76%	16.71%	11.96%
E-32 (total)	10.64%	16.58%	14.14%
E-32XS	21.57%	18.67%	21.57%
E-32S	10.87%	16.58%	15.07%
E-32M	8.86%	16.22%	13.06%
E-32L	5.93%	15.74%	10.12%
E-34	13.19%	16.50%	16.39%
E-35	20.47%	18.69%	17.39%
Water Pumping	3.82%	12.30%	8.02%
Street Lighting	54.31%	19.41%	21.99%
Dusk-to-Dawn	14.15%	19.36%	18.35%
Total	16.99%	16.99%	16.99%

Q. Please explain the basis for your proposal to move Residential rates halfway to cost of service.

A. In my opinion, moving Residential rates halfway to cost of service strikes a reasonable balance between setting rates based on cost while taking into consideration the principle of gradualism. At APS's proposed revenue requirement, my rate spread proposal would keep the Residential base rate increase within 2.4 percentage points of the system average increase in base rates.

Q. Please explain the basis for your proposed treatment of Rate 20 and Street Lighting.

A. The rates for both of these customer classes are significantly below cost of service. I recommend that rates for these two classes be moved closer to cost; at the same time, in the interest of gradualism, I am recommending capping the base rate increase for these two classes at five percentage points above the system average base rate increase. So, for example, at APS's proposed base rate increase of 16.99 percent, the base rate increase for these two classes would be capped at 21.99 percent.

Q. Please explain the basis for your proposed treatment of Rates 34 and 35.

A. Rates 34 and 35 serve customers with demands greater than 3,000 kilowatts. The difference between the two rate schedules is that the charges for Rate 35 are differentiated on a time-of-use ("TOU") basis, whereas the charges for Rate 34 are not. Because these two rate schedules serve the same set of eligible customers, it is important to maintain a rational relationship between their respective designs. For example, it would make no sense to reduce Rate 34 significantly relative to Rate 35, so as to force Rate 35 customers to abandon TOU pricing and migrate to the flat energy charges of Rate 34. For this reason, I recommend treating the two rate schedules on a collective basis for rate spread purposes. Specifically, I am recommending that rates for these two rate schedules be set, collectively, equal to cost of service, such that there is no subsidy in or out of this group. Further, as the cost of service study indicates that Rate 34 warrants a smaller rate increase than Rate 35, I am recommending that the base rate increase for Rate 34 be set 1.0 percentage point below the base rate increase for Rate 35.

Q. Please explain the basis of your recommended treatment for Rate E-32.

A. As explained by APS witness Gregory A DeLizio, APS is proposing to divide the current Rate E-32 class into four separate rate schedules differentiated by size: E-32-XS, E-32-S, E-32-M, and E-32-L. This change is consistent with the recommendation of Staff as discussed on page 74 of Decision No. 69633 in Docket No. E-01345A-05-0816. APS's cost-of-service analysis demonstrates that the Company's cost recovery from this group of customers increases steadily as customer size increases: the Rate E-32-XS group is under-recovering its costs whereas the E-32-L group is earning some of the highest returns on the system.

In my opinion, the APS rate spread does not adequately reflect this differentiation in cost-of-service results across this group. For example, Rate E-32-XS is slated to receive an increase that is 2.90 percent below cost of service, whereas Rate E-32-L would receive an increase that is 9.81 percent above its cost-of-service. (See Table KCH-3.) The primary reason to split Rate E-32 into distinct rate schedules is to better reflect cost of service. This objective will be better met with my rate spread proposal.

Q. Have you prepared an analysis that compares the AECC rate spread proposal to the APS rate spread proposal net of current PSA revenues?

A. Yes. This information is presented in Table KCH-5, below. It is compiled from information in Attachments KCH-10, KCH-11, and KCH-12. The information in this table reflects the same rate changes shown in Table KCH-4, except the impacts are shown net of the current PSA revenues from each class.

Table KCH-5

Comparison of AECC Rate Spread to APS Rate Spread
Net of Current PSA Revenues
At APS's Proposed Revenue Requirement

Class	Rate Change per APS COS	APS Proposed Rate Change	AECC Proposed Rate Change
Residential	17.03%	12.73%	14.75%
General Service	6.52%	11.42 %	9.30%
E-20	48.08%	15.34%	17.06%
GS TOU	2.15%	10.64%	6.13%
E-32 (total)	5.90%	11.59%	9.25%
E-32XS	17.67%	14.87%	17.67%
E-32S	6.61%	12.09%	10.64%
E-32M	3.93%	10.96%	7.94%
E-32L	0.60%	9.92%	4.58%
E-34	6.76%	9.88%	9.78%
E-35	12.62%	10.96%	9.74%
Water Pumping	(1.43)%	6.62%	2.56%
Street Lighting	49.86%	15.97%	18.48%
Dusk-to-Dawn	12.58%	17.72%	16.72%
Total	12.09%	12.09%	12.09%

Q. What approach to rate spread should be adopted if the Company's requested revenue requirement is reduced by the Commission?

A. If the Company's requested rate increase is reduced by the Commission, I recommend that the revenue apportionment produced by the rate spread shown in Table KCH-4 (p. 17) should be used as the basis for spreading the smaller revenue change.

Q. Please explain your recommendation further.

A. When I refer to the "revenue apportionment produced by the rate spread shown in Table KCH-4" I am referring to each class's percentage share of total revenue requirement that results from that spread. For example, under my

proposed spread, Residential customers would pay 52.11 percent of the total revenue requirement (see Attachment KCH-13). If the Commission agrees that this proposed rate spread is reasonable, then by extension, the corresponding revenue apportionment is reasonable as well.

My recommendation is to retain the percentage revenue apportionment that results from my proposed rate spread and to apply this revenue apportionment to whatever final revenue requirement is approved by the Commission. This type of approach (determining a reasonable revenue apportionment first, then applying it to the resulting revenue requirement) is standard in some jurisdictions such as Minnesota, and was recently adopted in Washington. The advantage of this approach is that it balances the application of gradualism with moving toward cost-of-service. If there is a determination that a given revenue apportionment reasonably accomplishes this balance, then this balance should be retained for a range of different revenue requirements. My recommendation accomplishes this objective.

Q. Do you have an example to illustrate how your approach would work?

A. Yes. An example is presented in Attachment KCH-13. In this example, the revenue apportionment associated with my proposed rate spread at APS's proposed revenue requirement is first determined. Next, we assume that the Commission reduces APS's proposed revenue increase by $100 million. The resulting rate spread is then calculated by holding the revenue apportionment constant. The results are summarized in Table KCH-6, below. The percentage

changes in this table are shown both for base rates (comparable to Table KCH-4) and for rate changes net of PSA revenues (comparable to Table KCH-5).

Table KCH-6

AECC Recommended Rate Spread Approach
Example Illustrating $100 Million Revenue Reduction to APS Revenue Proposal

Class	AECC Proposed Base Rate Change	AECC Proposed Rate Change Net of Current PSA Revenues
Residential	15.49%	11.02%
General Service	10.80%	5.75%
E-20	18.03%	13.26%
GS TOU	8.32%	2.69%
E-32 (total)	10.43%	5.70%
E-32XS	17.62%	13.85%
E-32S	11.33%	7.05%
E-32M	9.39%	4.43%
E-32L	6.55%	1.19%
E-34	12.61%	6.22%
E-35	13.58%	6.18%
Water Pumping	4.51%	(0.77)%
Street Lighting	18.03%	14.63%
Dusk-to-Dawn	14.50%	12.93%
Total	13.19%	8.45%

Rate Design

Q. Do you have any concerns with respect to APS's proposed rate design?

A. Yes. For Rate E-35, APS is proposing an inordinately large percentage increase in the demand charge for the Delivery Service component for customers taking service at transmission voltage. Specifically, the current demand charge for Delivery Service for E-35 is $0.303 per on-peak kW, plus $0.030 per off-peak kW. In this proceeding, APS is proposing an increase in this charge to $0.874 per

on-peak kW plus $0.086 per off-peak kW – an overall increase in excess of 185 percent. This change is dramatically greater than the Company's overall proposed increase in base rates for E-35 of 18.69 percent. This proposal would have an obviously negative impact to customers taking service at transmission voltage on Rate E-35. At the same time, APS is proposing to reduce the Delivery Charge for the other voltage levels on Rate E-35. The net effect is to reduce the differential between the primary voltage delivery charge and the transmission voltage delivery charge from $3.746 per kW-month to $2.845 per kW-month.

Q. By way of background, why do customers taking service at transmission voltage pay a lower Delivery Charge than customers taking service at secondary or primary voltage?

A. The Delivery Charge recovers APS's costs associated with its distribution system. Transmission voltage customers take service directly from the transmission system and do not use the distribution system; thus, the Delivery Charge for these customers should be zero or minimal.

Q. Is APS also proposing an extraordinary increase in the Delivery Service charges for Rate E-34?

A. No. Nor is APS proposing to reduce the Delivery Charges for primary and secondary voltage for Rate E-34 as significantly as for Rate E-35. As a result, APS's changes create a significant divergence in the proposed Delivery Charges between Rates E-34 and E-35. This divergence is shown in Table KCH-7, below.

Table KCH-7

Comparison of Rate E-34 and E-35 Delivery Charges

	Current Unbundled Delivery Charge	APS Proposed Unbundled Delivery Charge
Rate Schedule E-34		
Secondary Service	$4.959/kW	$4.577/kW
Primary Service	$4.169/kW	$3.971/kW
Transmission Service	$0.239/kW	$0.207/kW
Voltage Discount between Transmission and Primary	$3.930/kW	$3.764/kW
Rate Schedule E-35		
Secondary Service		
On-Peak	$4.368/kW	$3.700/kW
Off-Peak	$0.437/kW	$0.370/kW
Total	$4.805/kW	$4.070/kW
Primary Service		
On-Peak	$3.708/kW	$3.459/kW
Off-Peak	$0.371/kW	$0.346/kW
Total	$4.079/kW	$3.805/kW
Transmission Service		
On-Peak	$0.303/kW	$0.874/kW
Off-Peak	$0.030/kW	$0.086/kW
Total	$0.333/kW	$0.960/kW
Voltage Discount between Transmission and Primary (Total)	$3.746/kW	$2.845/kW

As shown in Table KCH-7, the proposed Delivery Charge for transmission voltage service for Rate E-35 is much higher than that of Rate E-34, whereas the proposed Delivery Charges for primary and secondary voltage service on Rate E-35 are much lower than that of Rate E-34. This divergence makes little sense, as

Rates E-34 and E-35 serve the same set of eligible customers. As I stated above, the only difference between the two rates is that Rate E-35 is designed on a TOU basis and E-34 is not. I see no merit in charging a much higher Delivery Charge to a transmission voltage customer on Rate E-35 – where the customer pays energy charges that vary with time-of-day – compared to Rate E-34 – where the customer would pay a flat energy charge.

Q. What alternative do you recommend?

A. I recommend that the $3.764 Delivery Charge differential between primary voltage and transmission voltage that APS is proposing for Rate E-34 be applied to Rate E-35.[5] This differential is nearly identical to the differential that exists now for Rate E-35. My alternative would maintain a more rational relationship between Rates E-34 and E-35 and avoid undue negative rate impacts on E-35 customers taking service at transmission voltage, as would occur under the Company's proposal.

Q. Do you have any other rate design recommendations concerning Rates E-34 and E-35?

A. Yes. APS witness Gregory A. DeLizio is recommending a change in the terms of Rates E-34 and E-35 that would "require a customer to compensate the Company for the costs of additional third-party transmission service that is required solely to provide service to a specific customer or customers." Mr. DeLizio states that this provision would apply when APS must enter into transmission arrangements for new or increased transmission service with a third

party and those arrangements "can be directly attributable to a specific customer or customers."[6]

I recommend that this proposed change to the tariff be rejected. In my experience, this proposed provision is highly unusual in a retail tariff and would provide the utility with an inordinate amount of leverage in dealing with its customers. Moreover, APS's retail transmission charges are simply a straight pass-through of rates in the Company's Open Access Transmission Tariff, which are approved by FERC. APS's attempt to introduce additional retail transmission charges outside the purview of its FERC-approved transmission rates would create an ad hoc pricing regime with limited oversight and the potential for double recovery. Such a provision is not in the public interest and should be rejected.

Impact Fee

Q. What is APS proposing with respect to charging an Impact Fee for new customers?

A. APS's proposal is explained in Mr. Rumolo's direct testimony. Mr. Rumolo explains that in Decision No. 70185, the Commission approved revisions to Schedule 3 of the Company's tariff that requires new customers to pay for infrastructure investment required to serve them. Proceeds received from customers pursuant to Schedule 3 are booked as Contributions in Aid of Construction ("CIAC").

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[5] For Rate E-35, the differential between primary and transmission voltage would be calculated by comparing the sum of the on-peak and off-peak Delivery Charges for primary voltage to the sum of the on-peak and off-peak Delivery Charges for transmission voltage.
[6] Direct testimony of Gregory A. DeLizio, p. 33, lines 3-12.

As described by Mr. Rumolo, the CIAC proceeds result in an income tax cost to APS that is capitalized and included in rate base. The carrying cost of this "tax asset" is currently charged to all customers. The Impact Fee being proposed by APS would recover this carrying cost from the new customers whose CIAC payment resulted in the creation of the tax asset. Mr. Rumolo estimates that the Impact Fee revenue requirement for this portion of the proposed Impact Fee is $27 million. In addition, APS is proposing to recover certain incremental distribution-related costs through the Impact Fee, which Mr. Rumolo estimates would cost an additional $21 million per year.

Q. What is your assessment of the Company's Impact Fee proposal?

A. I support the adoption of the CIAC "tax asset" portion of the Impact Fee, as these costs are associated with the direct cost of providing facilities to serve the new customers' premises, which is a reasonable assignment of cost to cost causers. However, I am concerned with the portion of the proposed Impact Fee that is intended to recover incremental system costs. Assigning new customers a fee based on incremental system costs begins to take on the character of "vintage pricing," which is a pricing regime that charges customers discriminatory rates based upon the date at which they initiate utility service. This form of price discrimination raises many policy and economic questions and can result in many unintended consequences, including the undue stifling of economic development. My recommendation is to not adopt this portion of the proposed charge.

Q. Do you have any other comments on this proposal?

A. Yes. If the Impact Fee proposal is adopted it is essential that the revenue from the fee is fully credited against any rate increase awarded in this case.

Demand-Side Management Cost Recovery

Q. What changes to the recovery of demand-side management ("DSM") costs are being proposed by APS?

A. APS is proposing several changes to its DSM cost recovery. These proposed changes are presented by Mr. DeLizio. Specifically, APS is proposing to: (1) increase charges to customers to recover "lost revenues" attributable to DSM investments; (2) change the structure of the DSM Adjustor mechanism to recover costs prospectively, and (3) remove the current 10 percent cap on DSM incentive payments to the utility.

Q. What is your recommendation with respect to these proposed changes?

A. I recommend that these proposed changes be rejected by the Commission. In general, these changes would divert DSM dollars away from DSM projects and instead direct them to the Company's shareholders.

Q. What is the basic justification offered by APS for recovery of "lost revenues"?

A. The basic justification is that DSM projects reduce energy consumption, thereby depriving the Company of fixed cost recovery from sales that have been foregone. The gist of the argument is that the loss of margins attributable to DSM programs creates a disincentive for utilities to support DSM, and thus creates a bias in favor of supply-side resources.

1 **Q. What is your response to the "lost revenues" argument?**

2 A. The "lost revenues" argument is widely recited by utilities and is, in part,
3 an unintended consequence of efforts by regulatory commissions to reduce utility
4 risk through the adoption of fuel adjustor mechanisms. Utilities that are at risk for
5 recovery of fuel and purchased power costs have a natural economic incentive to
6 reduce high energy production costs through DSM. This incentive is evidently
7 reduced when utilities are assured recovery of high marginal fuel costs through
8 fuel adjustor mechanisms, such as APS's PSA (although the PSA still provides
9 some incentive through its 90/10 sharing provision). As fuel adjustor mechanisms
10 are an obvious benefit to utilities, the claim that "lost revenue" recovery is
11 necessary to remove the disincentive to undertake DSM is tantamount to
12 demanding a new benefit that is made necessary by virtue of having been awarded
13 a previous benefit. Viewed in this broader context, the argument is not persuasive.

14 It should also be borne in mind that any "lost revenues" from DSM are
15 short-term in nature. To the extent that DSM reduces sales levels, the utility is
16 able to re-establish its margins in its next rate filing reflecting the newsales
17 volumes. But perhaps more importantly, the argument that without "lost revenue"
18 recovery the utility is biased in favor of supply-side solutions does not square
19 with the jeremiad addressing the problems of regulatory lag filed by APS in this
20 proceeding. One of the reasons to invest in DSM is to avoid incurring new fixed
21 cost. One of the implicit assumptions in the utilities' "lost revenues" argument is
22 that the cost of supply-side alternatives is somehow recovered without regulatory
23 lag – which of course is not the case. The upshot is that a rational utility should

have an incentive to invest in DSM – without extra payments for "lost revenues" – if it allows the utility to avoid supply-side investments that are subject to regulatory lag.

Q. What is your response to APS's proposal to change the DSM Adjustor so that it recovers prospective costs rather than incurred costs?

A. I am concerned that setting the adjustor based on prospective costs will create a bias to set DSM charges higher than is necessary, to the detriment of customers. I believe it is sounder to continue to set the charge to recover actually-incurred costs.

Q. What is your response to APS's proposal to remove the cap on its incentive payments from DSM?

A. The current program already allows up to 10 percent of DSM dollars collected from customers to be paid to APS as an incentive, rather than going to fund DSM projects. In my opinion, diverting even more funds away from DSM programs is not a good use of customer money.

<u>Environmental Improvement Surcharge</u>

Q. What changes has APS proposed with respect to the Environmental Improvement Surcharge?

A. As explained by Mr. DeLizio, APS is proposing to modify the Environmental Improvement Surcharge ("EIS") such that it would work as an adjustor mechanism. In addition, rather than treating the EIS funds used for eligible projects as CIAC, as is required by the Commission, APS is proposing

that the EIS provide a return on investment and recovery of expenses based on the projected cost of approved environmental expenditures.

Q. What is your assessment of this proposal?

A. This issue was addressed at length by the Commission on pages 82-87 in Decision No. 69633 in Docket No. E-01345A-05-0816. The Commission determined that with customers providing the up-front capital for the EIS projects, these funds should be booked as CIAC when used by APS to finance eligible projects. I agree with this determination.

To the extent that the EIS is considered anew, I recommend that the Commission consider eliminating this surcharge in its entirety, consistent with my recommendation, in Docket No. E-01345A-05-0816, not to adopt this surcharge in the first instance.

Q. Why do you recommend that the Commission consider eliminating this surcharge?

A. Allowing a "stand-alone" rate adjustment for incremental environmental improvement costs is an example of "single-issue ratemaking," in which a single item is permitted to impact rates in isolation from all other rate considerations. In contrast, when regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. Unless it can be shown to involve a compelling public interest, single-issue ratemaking is generally not sound regulatory policy, as it ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move

rates in the opposite direction from the single-issue change. There is no compelling reason to permit single-issue ratemaking in this instance.

Q. Are there circumstances that warrant exceptions to preclusions against single-issue ratemaking?

A. There are certain types of cost increases that regulatory commissions have come to allow without the benefit of conducting a general rate case. Because such exceptions constitute a form of single-issue ratemaking, it is not unusual for regulatory commissions to identify criteria that must be met for such treatment to be allowed, such as whether the costs in question exhibit volatility and/or whether the costs are largely outside the utility's control. In light of such criteria, the single-issue adjustments most commonly adopted are commodity and power cost adjustment mechanisms, such as the PSA mechanism approved by the Commission for APS.

Q. Do environmental improvement costs fit the description of "costs that are outside the utility's control" or "costs that exhibit volatility?"

A. Not really. While APS is subject to current and future provisions governing environmental quality, these provisions are long-term in nature and do not change from month to month the way fuel costs change.

Q. Are you opposed to APS being able to recover prudently-incurred environmental improvement costs?

A. No, I am not. I am opposed to adoption of single-issue adjustment mechanisms absent a compelling public interest. The appropriate forum for

1 establishing rates to recover prudently-incurred utility investment is a general rate

2 proceeding in which all cost and revenue information can be considered.

3 **Q. Does this conclude your direct testimony?**

4 A. Yes, it does.

Summary of APS' Cost of Service Results Excluding PSA Revenue at APS' Proposed $448 Million Base Revenue Increase

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	OPERATING INCOME	203,111,908	84,187,567	114,977,528	(90,787)	1,468,499	109,748,343	15,075,886	32,042,297	30,888,799	31,741,361
4	CURRENT RATE OF RETURN	3.79%	2.85%	5.04%	-0.82%	5.93%	5.49%	3.53%	5.67%	5.87%	6.57%
5	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%	8.86%
6	RETURN REQ FOR TARGETED ROR	474,892,852	261,765,192	202,228,424	985,366	2,194,787	177,263,501	37,816,323	50,068,495	46,601,817	42,776,867
7	SALES REVENUE REQ TARGETED ROR	3,085,640,806	1,639,878,045	1,384,052,449	5,041,823	16,626,709	1,157,851,176	211,338,530	303,084,506	318,289,526	325,138,614
8	REVENUE DEFICIENCY SALES REV	448,193,717	292,845,079	143,883,492	1,774,665	1,197,717	111,337,592	37,500,955	29,726,872	25,912,238	18,197,527
9	PERCENT INCREASE REQUIRED	16.99%	21.74%	11.60%	54.32%	7.76%	10.64%	21.57%	10.87%	8.86%	5.93%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
10	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
11	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
12	OPERATING INCOME	4,442,684	(591,210)	2,082,640	(20,057)	1,884,230
13	CURRENT RATE OF RETURN	3.48%	-0.50%	6.91%	-0.03%	6.61%
14	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%
15	RETURN REQ FOR TARGETED ROR	11,302,889	10,481,881	2,670,589	5,701,146	2,527,501
16	SALES REVENUE REQ TARGETED ROR	97,055,192	107,477,548	26,345,775	26,807,718	8,556,819
17	REVENUE DEFICIENCY SALES REV	11,313,072	18,260,445	969,588	9,434,741	1,060,817
18	PERCENT INCREASE REQUIRED	13.19%	20.47%	3.82%	54.31%	14.15%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.

Summary of APS' Cost of Service Results Including Current PSA Rate Revenue at APS' Proposed $448 Million Base Revenue Increase ($333 Million Increase Net of Current PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PRESENT RATES)	115,420,488	54,227,260	59,222,740	137,568	847,004	46,854,460	5,764,972	10,946,928	13,874,484	16,268,076
4	OPERATING INCOME WITH PSA	273,102,892	117,070,977	150,890,198	(7,366)	1,982,122	138,160,887	18,571,765	38,680,514	39,302,286	41,606,322
5	CURRENT RATE OF RETURN	5.10%	3.96%	6.61%	-0.07%	8.00%	6.91%	4.35%	6.84%	7.47%	8.62%
6	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%	0	8.86%	8.86%	8.86%	8.86%
7	RETURN REQ FOR TARGETED ROR	474,892,852	261,765,192	202,228,424	985,366	2,194,787	177,263,501	37,816,323	50,068,495	46,601,817	42,776,867
8	SALES REVENUE REQ TARGETED ROR	3,085,640,806	1,639,878,045	1,384,052,449	5,041,823	16,626,709	1,157,851,176	211,338,530	303,084,506	318,289,526	325,138,614
9	REVENUE DEFICIENCY SALES REV	332,773,229	238,617,819	84,660,752	1,637,097	350,713	64,483,132	31,735,983	18,779,944	12,037,754	1,929,451
10	PERCENT INCREASE REQUIRED	12.09%	17.03%	6.52%	48.08%	2.15%	5.90%	17.67%	6.61%	3.93%	0.60%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PRESENT RATES)	5,164,112	6,219,596	1,351,080	515,000	104,408
14	OPERATING INCOME WITH PSA	7,574,201	3,180,353	2,901,935	292,239	1,947,543
15	CURRENT RATE OF RETURN	5.94%	2.69%	9.63%	0.45%	6.83%
16	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%
17	RETURN REQ FOR TARGETED ROR	11,302,889	10,481,881	2,670,589	5,701,146	2,527,501
18	SALES REVENUE REQ TARGETED ROR	97,055,192	107,477,548	26,345,775	26,807,718	8,556,819
19	REVENUE DEFICIENCY SALES REV	6,148,960	12,040,849	(381,492)	8,919,741	956,409
20	PERCENT INCREASE REQUIRED	6.76%	12.62%	-1.43%	49.86%	12.58%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls

Note: PSA revenue at present rates derived by applying 4 mills/kWh to the Schedule H-2 test year energy for each rate schedule. The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

Summary of APS' Cost of Service Results Including Projected PSA Rate Revenue at APS' Proposed $448 Million Base Revenue Increase ($278 Million Increase Net of Projected PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PROJECTED RATES)	169,977,000	79,859,000	87,217,000	203,000	1,246,000	69,003,000	8,490,000	16,122,000	20,433,000	23,958,000
4	OPERATING INCOME WITH PSA	306,185,961	132,614,064	167,865,917	32,312	2,224,073	151,591,762	20,224,222	41,818,678	43,279,370	46,269,492
5	CURRENT RATE OF RETURN	5.71%	4.49%	7.35%	0.29%	8.98%	7.58%	4.74%	7.40%	8.23%	9.58%
6	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%	0	8.86%	8.86%	8.86%	8.86%
7	RETURN REQ FOR TARGETED ROR	474,892,852	261,765,192	202,228,424	985,366	2,194,787	177,263,501	37,816,323	50,068,495	46,601,817	42,776,867
8	SALES REVENUE REQ TARGETED ROR	3,085,640,806	1,639,878,045	1,384,052,449	5,041,823	16,626,709	1,157,851,176	211,338,530	303,084,506	318,289,526	325,138,614
9	REVENUE DEFICIENCY SALES REV	278,216,717	212,986,079	56,666,492	1,571,665	(48,283)	42,334,592	29,010,955	13,604,872	5,479,238	(5,760,473)
10	PERCENT INCREASE REQUIRED	9.91%	14.93%	4.27%	45.29%	-0.29%	3.80%	15.91%	4.70%	1.75%	-1.74%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PROJECTED RATES)	7,605,000	9,160,000	1,989,000	758,000	154,000
14	OPERATING INCOME WITH PSA	9,054,356	4,963,414	3,288,770	439,594	1,977,616
15	CURRENT RATE OF RETURN	7.10%	4.20%	10.91%	0.68%	6.93%
16	TARGETED RATE OF RETURN	8.86%	8.86%	8.86%	8.86%	8.86%
17	RETURN REQ FOR TARGETED ROR	11,302,889	10,481,881	2,670,589	5,701,146	2,527,501
18	SALES REVENUE REQ TARGETED ROR	97,055,192	107,477,548	26,345,775	26,807,718	8,556,819
19	REVENUE DEFICIENCY SALES REV	3,708,072	9,100,445	(1,019,412)	8,676,741	906,817
20	PERCENT INCREASE REQUIRED	3.97%	9.25%	-3.73%	47.86%	11.85%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.
Data Source: APS Schedule H-2, Column (I).

Note: The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

Summary of APS' Proposed Revenue Spread Excluding PSA Revenue
at APS' Proposed $448 Million Base Revenue Increase

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	OPERATING INCOME	203,111,908	84,187,567	114,977,528	(90,787)	1,468,499	109,748,343	15,075,886	32,042,297	30,888,799	31,741,361
4	CURRENT RATE OF RETURN	3.79%	2.85%	5.04%	-0.82%	5.93%	5.49%	3.53%	5.67%	5.87%	6.57%
5	SALES REVENUE (PROPOSED RATES)	3,085,641,089	1,579,682,966	1,447,768,957	3,927,158	18,006,992	1,220,047,584	206,300,575	318,683,634	339,803,288	355,260,087
6	APS PROPOSED REVENUE INCREASE	448,194,000	232,650,000	207,600,000	660,000	2,578,000	173,534,000	32,463,000	45,326,000	47,426,000	48,319,000
7	PERCENT INCREASE	16.99%	17.27%	16.74%	20.20%	16.71%	16.58%	18.67%	16.58%	16.22%	15.74%
8	OPERATING INCOME WITH INCREASE	474,896,750	225,266,527	240,866,168	309,437	3,031,798	214,979,360	34,761,449	59,527,983	59,647,926	61,042,002
9	PROPOSED RATE OF RETURN	8.86%	7.62%	10.55%	2.78%	12.24%	10.75%	8.14%	10.53%	11.34%	12.64%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
10	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
11	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
12	OPERATING INCOME	4,442,684	(591,210)	2,082,640	(20,057)	1,884,230
13	CURRENT RATE OF RETURN	3.48%	-0.50%	6.91%	-0.03%	6.61%
14	SALES REVENUE (PROPOSED RATES)	99,891,120	105,896,103	28,497,187	20,744,977	8,947,002
15	APS PROPOSED REVENUE INCREASE	14,149,000	16,679,000	3,121,000	3,372,000	1,451,000
16	PERCENT INCREASE	16.50%	18.69%	12.30%	19.41%	19.36%
17	OPERATING INCOME WITH INCREASE	13,022,637	9,522,936	3,975,215	2,024,724	2,764,117
18	PROPOSED RATE OF RETURN	10.21%	8.05%	13.19%	3.15%	9.69%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.
Data Source: APS Schedule H-2

Summary of APS' Proposed Revenue Spread Including Current PSA Revenue at APS' Proposed $448 Million Base Revenue Increase ($333 Million Increase Net of Current PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PRESENT RATES)	115,420,488	54,227,260	59,222,740	137,568	847,004	46,854,460	5,764,972	10,946,928	13,874,484	16,268,076
4	OPERATING INCOME WITH PSA	273,102,892	117,070,977	150,890,198	(7,366)	1,982,122	138,160,887	18,571,765	38,680,514	39,302,286	41,606,322
5	CURRENT RATE OF RETURN	5.10%	3.96%	6.61%	-0.07%	8.00%	6.91%	4.35%	6.84%	7.47%	8.62%
6	SALES REVENUE (PROPOSED RATES)	3,085,641,085	1,579,682,966	1,447,768,953	3,927,158	18,006,992	1,220,047,580	206,300,571	318,683,634	339,803,288	355,260,087
7	APS PROPOSED REVENUE INCREASE	332,773,508	178,422,740	148,377,256	522,432	1,730,996	126,679,536	26,698,024	34,379,072	33,551,516	32,050,924
8	PERCENT INCREASE	12.09%	12.73%	11.42%	15.34%	10.64%	11.59%	14.87%	12.09%	10.96%	9.92%
9	OPERATING INCOME WITH INCREASE	474,896,748	225,266,527	240,866,166	309,437	3,031,798	214,979,358	34,761,447	59,527,983	59,647,926	61,042,002
10	PROPOSED RATE OF RETURN	8.86%	7.62%	10.55%	2.78%	12.24%	10.75%	8.14%	10.53%	11.34%	12.64%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PRESENT RATES)	5,164,112	6,219,596	1,351,080	515,000	104,408
14	OPERATING INCOME WITH PSA	7,574,201	3,180,353	2,901,935	292,239	1,947,543
15	CURRENT RATE OF RETURN	5.94%	2.69%	9.63%	0.45%	6.83%
16	SALES REVENUE (PROPOSED RATES)	99,891,120	105,896,103	28,497,187	20,744,977	8,947,002
17	APS PROPOSED REVENUE INCREASE	8,984,888	10,459,404	1,769,920	2,857,000	1,346,592
18	PERCENT INCREASE	9.88%	10.96%	6.62%	15.97%	17.72%
19	OPERATING INCOME WITH INCREASE	13,022,637	9,522,936	3,975,215	2,024,724	2,764,117
20	PROPOSED RATE OF RETURN	10.21%	8.05%	13.19%	3.15%	9.69%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls

Note: PSA revenue at present rates derived by applying 4 mills/kWh to the Schedule H-2 test year energy for each rate schedule. The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

Summary of APS' Proposed Revenue Spread Including Projected PSA Revenue at APS' Proposed $448 Million Base Revenue Increase ($278 Million Increase Net of Projected PSA Revenue)

Line No.	DESCRIPTION	TOTAL RETAIL	RESIDENTIAL	TOTAL GENERAL SERVICE	E-20 (Church Rate)	General Ser. TOU	E-30, E-32 SUBTOTAL	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)
1	RATE BASE	5,359,964,470	2,954,460,405	2,282,487,853	11,121,512	24,771,860	2,000,716,718	426,820,799	565,107,163	525,979,871	482,808,885
2	SALES REVENUE (PRESENT RATES)	2,637,447,089	1,347,032,966	1,240,168,957	3,267,158	15,428,992	1,046,513,584	173,837,575	273,357,634	292,377,288	306,941,087
3	PSA REVENUE (PROJECTED RATES)	169,977,000	79,859,000	87,217,000	203,000	1,246,000	69,003,000	8,490,000	16,122,000	20,433,000	23,958,000
4	OPERATING INCOME WITH PSA	306,185,961	132,614,064	167,865,917	32,312	2,224,073	151,591,762	20,224,222	41,818,678	43,279,370	46,269,492
5	CURRENT RATE OF RETURN	5.71%	4.49%	7.35%	0.29%	8.98%	7.58%	4.74%	7.40%	8.23%	9.58%
6	SALES REVENUE (PROPOSED RATES)	3,085,641,089	1,579,682,966	1,447,768,957	3,927,158	18,006,992	1,220,047,584	206,300,575	318,683,634	339,803,288	355,260,087
7	APS PROPOSED REVENUE INCREASE	278,217,000	152,791,000	120,383,000	457,000	1,332,000	104,531,000	23,973,000	29,204,000	26,993,000	24,361,000
8	PERCENT INCREASE	9.91%	10.71%	9.07%	13.17%	7.99%	9.37%	13.15%	10.09%	8.63%	7.36%
9	OPERATING INCOME WITH INCREASE	474,896,750	225,266,527	240,866,168	309,437	3,031,798	214,979,360	34,761,449	59,527,983	59,647,926	61,042,002
10	PROPOSED RATE OF RETURN	8.86%	7.62%	10.55%	2.78%	12.24%	10.75%	8.14%	10.53%	11.34%	12.64%

Line No.	DESCRIPTION	E-34	E-35	E-38,221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
11	RATE BASE	127,572,106	118,305,657	30,142,093	64,347,024	28,527,095
12	SALES REVENUE (PRESENT RATES)	85,742,120	89,217,103	25,376,187	17,372,977	7,496,002
13	PSA REVENUE (PROJECTED RATES)	7,605,000	9,160,000	1,989,000	758,000	154,000
14	OPERATING INCOME WITH PSA	9,054,356	4,963,414	3,288,770	439,594	1,977,616
15	CURRENT RATE OF RETURN	7.10%	4.20%	10.91%	0.68%	6.93%
16	SALES REVENUE (PROPOSED RATES)	99,891,120	105,896,103	28,497,187	20,744,977	8,947,002
17	APS PROPOSED REVENUE INCREASE	6,544,000	7,519,000	1,132,000	2,614,000	1,297,000
18	PERCENT INCREASE	7.01%	7.64%	4.14%	14.42%	16.95%
19	OPERATING INCOME WITH INCREASE	13,022,637	9,522,936	3,975,215	2,024,724	2,764,117
20	PROPOSED RATE OF RETURN	10.21%	8.05%	13.19%	3.15%	9.69%

Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls.
Data Source: APS Schedule H-2, Column (l).

Note: The additional net income impact was derived by applying the operating income factor of 60.64% (see APS Schedule C-3, p. 1 of 1) to the PSA revenue.

AECC Recommended Rate Spread at APS' Requested Revenue Increase

AECC Recommended Revenue Increase for each Customer Class based on APS's Cost of Service Study

E-20 & Outdoor/Streetlighting Adder above System Average Increase = 5.00%

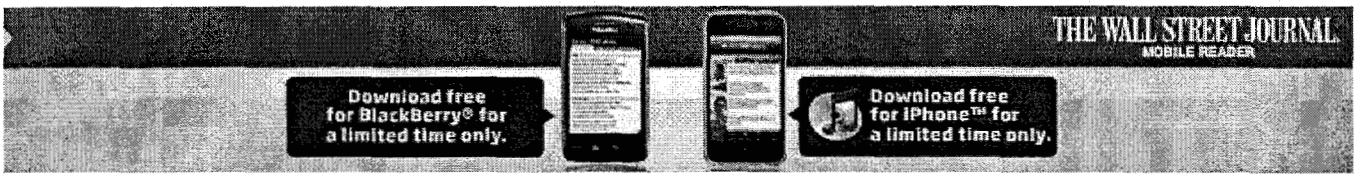
Gen. Serv. TOU, E-32 (Greater than 20 kW), Water Pumping & Dusk to Dawn Adder Above Cost = 4.20%

	(a)	(b)	(c)	(d)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Line No.	Rate Class	Current Retail Base Revenues[1]	Rate Base[1]	Return Req'd Return @ Equal ROR[1]	Required Revenue Increase[1]	Req'd Percent Change	AECC Recommended Base Revenue Increase	AECC Base Percent Change	AECC Recommended Base Revenue Net of Current PSA Revenue	AECC Base Percent Change Net of Current PSA	AECC Recommended Base Revenue Net of Projected PSA Revenue	AECC Base Percent Change Net of Projected PSA
1	Residential	$1,347,032,966	$2,954,460,405	$261,765,192	$292,845,079	21.74%	$260,876,345	19.37%	$206,649,085	14.75%	$181,017,345	12.69%
2	General Service											
3	E-20	$3,267,158	$11,121,512	$985,366	$1,774,665	54.32%	$718,561	21.99%	$580,993	17.06%	$515,561	14.86%
4	General Serv. TOU	$15,428,992	$24,771,860	$2,194,787	$1,197,717	7.76%	$1,845,025	11.96%	$998,021	6.13%	$599,025	3.59%
5	E-30, E-32 (0 - 20 kW)	$173,837,575	$426,820,799	$37,816,323	$37,500,955	21.57%	$37,500,955	21.57%	$31,735,983	17.67%	$29,010,955	15.91%
6	E-32 (21 - 100 kW)	$273,357,634	$565,107,163	$50,068,495	$29,726,872	10.87%	$41,195,313	15.07%	$30,248,385	10.64%	$25,073,313	8.66%
7	E-32 (101 - 400 kW)	$292,377,288	$525,979,871	$46,601,817	$25,912,238	8.86%	$38,178,629	13.06%	$24,304,145	7.94%	$17,745,629	5.67%
8	E-32 (401+ kW)	$306,941,087	$482,808,885	$42,776,867	$18,197,527	5.93%	$31,074,928	10.12%	$14,806,852	4.58%	$7,116,928	2.15%
9	E-30, E-32 Subtotal	$1,046,513,584	$2,000,716,718	$177,263,501	$111,337,592	10.64%	$147,949,825	14.14%	$101,095,365	9.25%	$78,946,825	7.08%
10	E-34	$85,742,120	$127,572,106	$11,302,889	$11,313,072	13.19%	$14,055,843	16.39%	$8,891,731	9.78%	$6,450,843	6.91%
11	E-35	$89,217,103	$118,305,657	$10,481,881	$18,260,445	20.47%	$15,517,674	17.39%	$9,298,078	9.74%	$6,357,674	6.46%
12	General Service Total	$1,240,168,957	$2,282,487,853	$202,228,424	$143,883,492	11.60%	$180,086,928	14.52%	$120,864,188	9.30%	$92,869,928	7.00%
13	Water Pumping (E-38, E-221)	$25,376,187	$30,142,093	$2,670,589	$969,588	3.82%	$2,034,220	8.02%	$683,140	2.56%	$45,220	0.17%
14	Outdoor/Street Lighting	$17,372,977	$64,347,024	$5,701,146	$9,434,741	54.31%	$3,820,920	21.99%	$3,305,920	18.48%	$3,062,920	16.89%
15	Dusk to Dawn	$7,496,002	$28,527,095	$2,527,501	$1,060,817	14.15%	$1,375,304	18.35%	$1,270,896	16.72%	$1,221,304	15.96%
16	ACC Total	$2,637,447,089	$5,359,964,470	$474,892,852	$448,193,717	16.99%	$448,193,717	16.99%	$332,773,229	12.09%	$278,216,717	9.91%

1. Data Source: Rumolo_Direct Workpaper DJR_WP01, DJR_WP03_APS08736, APS08738.xls

AECC Recommended Rate Spread Approach
Example Illustrating a $100 Million Revenue Reduction to APS' Requested Increase

	(a)	(b)	(c)	(d)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
						Revenue Spread at Assumed $348 Million Increase						
Line No.	Rate Class	Current Retail Base Revenues	AECC Recommended Base Revenue Increase at APS' Requested Increase	AECC Recommended Retail Base Revenue at APS' Requested Increase	Revenue Apportionment Percentage	AECC Recommended Retail Base Revenue	AECC Recommended Base Revenue Increase	AECC Base Percent Change	AECC Recommended Base Revenue Increase Net of Current PSA Revenue	AECC Base Percent Change Net of Current PSA	AECC Recommended Base Revenue Increase Net of Projected PSA Revenue	AECC Base Percent Change Net of Projected PSA
1	Residential	$1,347,032,966	$260,876,345	$1,607,909,311	52.11%	$1,555,698,953	$208,665,987	15.49%	$154,438,727	11.02%	$128,806,987	9.03%
2	General Service											
3	E-20	$3,267,158	$718,561	$3,985,719	0.13%	$3,856,299	$589,141	18.03%	$451,573	13.26%	$386,141	11.13%
4	General Serv. TOU	$15,428,992	$1,845,025	$17,274,017	0.56%	$16,713,113	$1,284,121	8.32%	$437,117	2.69%	$38,121	0.23%
5	E-30, E-32 (0 - 20 kW)	$173,837,575	$37,500,955	$211,338,530	6.85%	$204,476,165	$30,638,590	17.62%	$24,873,618	13.85%	$22,148,590	12.15%
6	E-32 (21 - 100 kW)	$273,357,634	$41,195,313	$314,552,947	10.19%	$304,339,111	$30,981,477	11.33%	$20,034,549	7.05%	$14,859,477	5.13%
7	E-32 (101 - 400 kW)	$292,377,288	$38,178,629	$330,555,917	10.71%	$319,822,449	$27,445,161	9.39%	$13,570,677	4.43%	$7,012,161	2.24%
8	E-32 (401+ kW)	$306,941,087	$31,074,928	$338,016,015	10.95%	$327,040,310	$20,099,223	6.55%	$3,831,147	1.19%	($3,858,777)	-1.17%
9	E-30, E-32 Subtotal	$1,046,513,584	$147,949,825	$1,194,463,409	38.71%	$1,155,678,036	$109,164,452	10.43%	$62,309,992	5.70%	$40,161,452	3.60%
10	E-34	$85,742,120	$14,055,843	$99,797,963	3.23%	$96,557,428	$10,815,308	12.61%	$5,651,196	6.22%	$3,210,308	3.44%
11	E-35	$89,217,103	$15,517,674	$104,734,777	3.39%	$101,333,938	$12,116,835	13.58%	$5,897,239	6.18%	$2,956,835	3.01%
12	General Service Total	$1,240,168,957	$180,086,928	$1,420,255,885	46.03%	$1,374,138,814	$133,969,857	10.80%	$74,747,117	5.75%	$46,752,857	3.52%
13	Water Pumping (E-38, E-221)	$25,376,187	$2,034,220	$27,410,407	0.89%	$26,520,365	$1,144,178	4.51%	($206,902)	-0.77%	($844,822)	-3.09%
14	Outdoor/Street Lighting	$17,372,977	$3,820,920	$21,193,897	0.69%	$20,505,711	$3,132,734	18.03%	$2,617,734	14.63%	$2,374,734	13.10%
15	Dusk to Dawn	$7,496,002	$1,375,304	$8,871,306	0.29%	$8,583,246	$1,087,244	14.50%	$982,836	12.93%	$933,244	12.20%
16	ACC Total	$2,637,447,089	$448,193,717	$3,085,640,806	100.00%	$2,985,447,089	$348,000,000	13.19%	$232,579,512	8.45%	$178,023,000	6.34%



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AUGUST 12, 2009

Electricity Prices Plummet

BY REBECCA SMITH

Slack demand for electricity across the U.S. is leading to some of the sharpest reductions in power prices in recent years, offering a break for consumers and businesses who just a year ago were getting crunched by massive electricity bills.

On Friday, the nation's largest wholesale power market serving parts of 13 states east of the Rockies is expected to report that electricity demand fell 4.4% in the first half of the year. That helped to push down spot market prices by 40% during the first half of this year.

Wholesale electricity -- power furnished to utilities and other big ...

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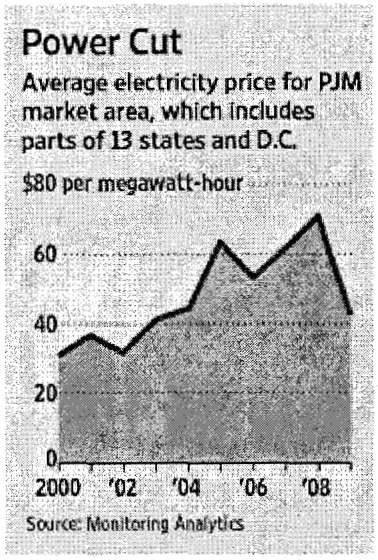
On Friday, the nation's largest wholesale power market serving parts of 13 states east of the Rockies is expected to report that electricity demand fell 4.4% in the first half of the year. That helped to push down spot market prices by 40% during the first half of this year.



Wholesale electricity -- power furnished to utilities and other big energy users -- cost an average of $40 a megawatt hour in the region, down from $66.40 a year earlier. The price declines in this market, which extends from Delaware to Michigan, come on top of a 2.7% drop in energy use in 2008 over 2007.

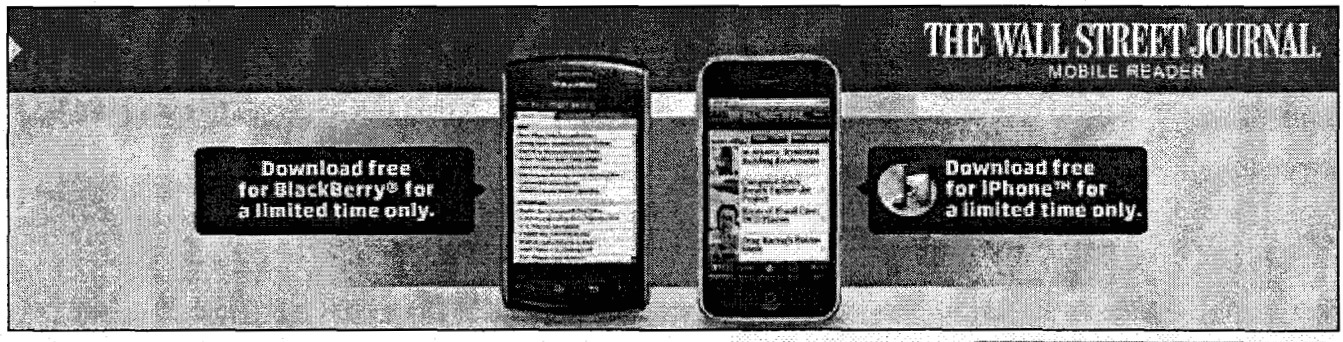
The falloff in demand represents a reversal of what has been one of the steadiest trends in business. For decades, the utility sector could rely on a gradual increase in electricity demand. In 45 of the past 58 years, year-over-year growth exceeded 2%. In fact, there only have been five years since 1950 in which electricity demand has dropped in absolute terms.

But this year is shaping up to have the sharpest falloff in more than half a century, and coming on top of declines in 2008, could be the first period of consecutive annual declines since at least 1950.

Dramatic price reductions don't immediately mean lower power bills for all consumers. That's because many customers pay prices based on long-term contracts. But lower prices will have a softening effect over time.

In California and Texas, a combination of cheap natural gas and lower industrial demand is putting pressure on prices.

In the Houston pricing zone, which has many power-gobbling refineries and chemical plants, the spot market price was $61.82 in June, versus $129.48 a megawatt hour a year earlier. Power demand in Texas is down 3.2% so far this year due to business contraction and reductions in employment which are causing many households to economize.



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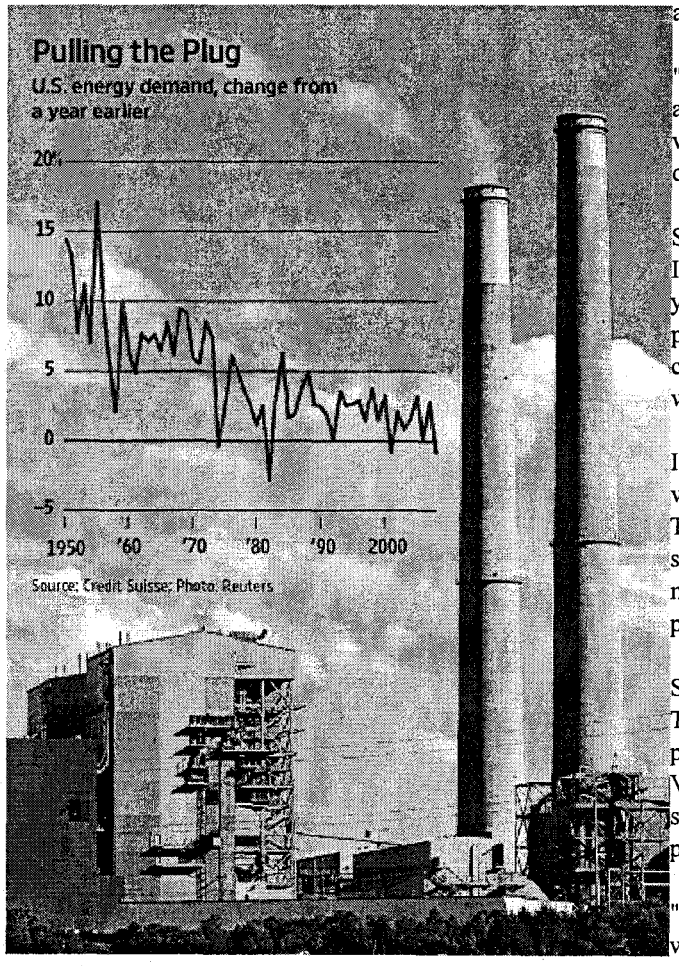
Just a year ago, many businesses and residential customers were reeling from electricity prices on the spot market that had spiked to historic highs, driven by high fuel prices and hot summer weather. Some businesses curtailed their operations because electricity and natural gas were too pricey.



But the flagging economy has resulted in a slump in demand that has jolted some energy markets. American Electric Power Co. and Southern Co., for example, both reported double-digit drops in industrial electricity use for the past quarter.

Meanwhile, natural gas, which strongly influences electricity prices, has fallen below $4 per million BTUs, or British thermal units. That's down from $12 at last year's peak.

For many businesses, the cost of electricity represents one of the few bright spots in a dismal economy. Andy Morgan, president of Pickard China Inc. in Antioch, Ill., which makes fine china, figures his electricity cost is down 30% to 40%.

Last year, when everything was spiking, he looked at different options -- including negotiating a fixed-price contract for energy with a supplier. He says he held off and now he's happy he did.

"We've definitely reaped savings," says Mr. Morgan, adding that "especially in a down economy, you'll take whatever you can get. That's one of the few blessings during this storm."

Slowdowns at major industrial companies such as Alcoa Inc. help account for the decline in electricity usage this year. The recession and drop in consumer demand for products that contain aluminum has caused the company to idle 20% of its smelting capacity worldwide this year.

In the U.S. the company has cut production at smelters, which are traditionally big energy users, in New York, Tennessee and Texas. Kevin Lowery, a company spokesman, said he did not believe that Alcoa has saved much money thus far because the company primarily purchases electricity through 25- to 35-year contracts.

Steel Dynamics Inc. is benefiting from lower pricing. The company operates five steel mills, with four purchasing electricity at spot market prices in Indiana, Virginia and West Virginia. The benefit, though, is smaller than it might be because the steelmaker is producing less steel this year.

"We're producing fewer tons, but every ton we produce we seek to minimize the costs and electricity is one of those," said Fred Warner, a company spokesman. Its mills are running at 50% capacity this year, down from 85% capacity last year.

Some wonder whether the deregulated markets of the Eastern U.S., Midwest, Texas and California will be especially hard hit if demand comes roaring back. That's because utilities in these markets no longer are required to build new resources. It's left up to the power generators to determine when the market conditions are ripe.

"There's more supply than demand and prices are really low so it doesn't make sense to build anything," says

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John Shelk, president of the Electric Power Supply Association in Washington, D.C., a group that represents power generators.

Many electricity markets throughout the country have implemented demand reduction programs that give consumers a further incentive to reduce power use. The 13-state PJM Interconnection market has been one of the most aggressive -- and has seen one of the steepest price drops.

A new report from the region's official market monitor found a strong correlation between falling prices and an increase in demand-reduction programs. In the PJM market, energy users can collect money through an auction process for pledging to cut energy use in future periods.

In May, PJM conducted an auction to ensure it will have the resources it believes it will need in 2012-13. About 6% of the winning bids came from those who pledged to cut energy use by a total of 8,000 megawatts in that future period.

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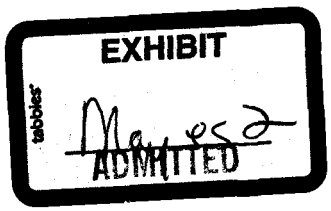
Pinnacle West Capital Corporation Q1 2009 Earnings Call Transcript



May 05, 2009 | about: PNW

Pinnacle West Capital Corporation (PNW)

Q1 2009 Earnings Call Transcript

May 5, 2009 12:00 pm ET

Executives

Rebecca Hickman – Director, IR

Don Brandt – Chairman and CEO

Jim Hatfield – SVP and CFO

Don Robinson – President and COO of APS

Analysts

Greg Gordon – Citigroup

Paul Patterson – Glenrock Associates

Paul Ridzon – KeyBanc

Daniel Sites [ph] – Dudek Research Group [ph]

Kevin Fallon – Blenheim Capital Management

Andrew Levy – Incremental Capital

Reza Hatefi – Decade

Chris Shelton – Millenium

Presentation

Operator

Good morning, my name is Jamal, and I'll be your conference operator today. At this time, I would like to welcome everyone to the first quarter 2009 earnings conference call. All lines have been placed on mute to prevent any background noise. After the speakers' remarks, there will be a question-and-answer session. (Operator instructions)

Thank you. Now, I would like to turn the call over to Miss Rebecca Hickman, Director of Investor Relations. You may begin, ma'am.

Rebecca Hickman

Thank you, Jamal. I'd like to thank everyone for participating in this conference call to review our first quarter earnings, recent developments, and operating performance. Our speakers today will be our Chairman and CEO, Don Brandt; and, our CFO, Jim Hatfield. John Robinson who is President and Chief Operating Officer of APS is also here with us.

Before I turn the call over to our speakers, I need to cover a few details with you. First, I encourage you to check the quarterly earnings and statistics section of our Web site. It contains extensive supplemental information on our earnings variances and quarterly operating statistics. Second, please note that all our references to per share amounts will be after income taxes and based on diluted shares outstanding. Third, we will be referring to slides today during this conference call and webcast. The slides are available on our Investor Relations Web site with the webcast, and with the Form 8-K filed this morning. During our prepared remarks we will give you verbal cues as we move through the slides.

Looking at slide two, it is my responsibility to advice you that this call and our slides will contain forward-looking statements based on current expectations. And the company assumes no obligation to update these statements. Because the actual results may differ materially from expectations, we caution you not to place undue reliance on these statements. Please refer to the forward-looking statements and the MD&A sections contained in our first quarter 2009 Form 10-Q, which was filed with the SEC this morning, as well as the risk factors section of our 2008 Form 10-K. All of which identifies some important factors that could cause actual results to differ materially from those contained in our forward-looking statements.

Next, during this call we will discuss certain non-GAAP financial measures. Our press release, the slides accompanying this webcast, and our filings with the SEC, all of which are posted on our Investor Relations Web site contained additional disclosures regarding these non-GAAP measures including reconciliations of these measures to the most comparable GAAP measures.

A replay of this call will be available on our Web site, www.pinnaclewest.com, for the next 30 days. It will also be available by telephone through May 12. Finally, this call and webcast are the property of Pinnacle West Capital Corporation, and any copying, transcription, redistribution, retransmission, or rebroadcast of this call, in whole or in part, without Pinnacle West's written consent is prohibited. At this point, I'll turn the call over to Don.

Don Brandt

Thanks, Becky. I'd like to thank everyone for joining us on the call today. We have been focused on excellence on operations throughout the organization and optimizing the positioning and value of Pinnacle West and our subsidiaries for the future.

Today, I will discuss several major milestones we have achieved since our last earnings call with you. Two weeks ago, we announced we have reached an agreement in principle to settle APS' pending retail rate case, and yesterday, a term sheet outlining the proposed settlement was filed with the Arizona Corporation Commission.

In late March, we completed the review of SunCor's strategies, markets, and properties, as a result we announced to plan to restructure SunCor by disposing a majority of its real estate assets. Also in March, The Nuclear Regulatory Commission recognized that Palo Verde operations have improved significantly and returned to plant to routine inspection and oversight.

I will discuss these and other operational and regulatory matters in some detail. Then I'll return the call over to Jim to discuss our first quarter results and other financial updates. I'll begin with the proposed rate settlement. Yesterday, APS, the ACC staff, and other parties to the pending retail rate case filed with the ACC a term sheet outlining the proposed settlement of the case along with the recommended schedule for filing a definitive settlement agreement and for the commission's consideration of the settlement.

Throughout the negotiation process, the discussions were open to all parties to the rate case. In fact, the vast majority of the parties did indeed participate. Through the settlement process APS and the parties agreed to a rate and financial stability plan that provides benefits for APS, our customers, our investors, and other stakeholders. Additionally, many provisions of the settlement are focused on advancing Arizona's sustainable energy future. Of course to achieve all of these benefits it is essential the commission approves the settlement as proposed.

Slide four outlines the primary benefits of the settlement as we see them from an investor's perspective. Among other things, the plan strengthens APS' financial position, supports the common dividend, and improves APS' ability to attract capital for needed infrastructure additions. It provides a greater level of cost recovery and return on investment for APS all providing rate stability for our customers. Completing the settlement also allows the opportunity for us to help shape Arizona's energy future outside continual rate cases.

Further, it continues APS' strong commitment to cost control and efficiency. And finally, it provides for a significant increase in energy efficiency programs and expands upon the current scope and magnitude of renewable energy programs.

Now, I will describe the major financial provisions of the settlement, which are outlined on slides five through eight. APS' annual base rate revenues will increase $207 million under the settlement effective January 1st of 2010. This result compares with $278 million in APS' request. As you recall you're currently collecting $65 million a year through our interim base rate sure charge that will continue until rate goes into an effect through a general rate case decision. Consequently, net base rate revenues would increase $142 million annually or about 5.4% when the settlement is implemented.

The proposed increase includes the following components, a non fuel related increase of $196.3 million and a net fuel related increase of $11.2 million. The proposed rates are based on allowed return equity of 11%, compared with the 11.5% originally requested by APS. Besides the base rate provisions, there are a number of other financial provisions. In 2010 to 2012 or the earlier conclusion of APS 's next general rate case payment collected for line extensions and upgrades will be recorded as revenues instead of contributions in aid of construction as they are now.

At this time, we estimate this change will add pretax revenue of $23 million in 2010, $25 million in 2011, and $49 million in 2012. These estimates are of course highly dependent upon the number and type of new customers added by APS during those years and are provided only to give you some ideas of relative significance of this change in accounting for such proceeds. In 2011 and 2012, APS will be allowed to defer for future rate recovery, increases in cost for pensions and other post retirement benefits above the 2007 test year amounts subject to certain Caps.

The provision of the proposed settlement underscores APS' ongoing cost management and efficiency efforts. In December 2008, interim rate decision, the commission asked us to review APS' expenses targeting reductions of at least $20 million. As a result of the proposed settlement, APS will identify an additional $10M of pretax expense reductions to be implemented in 2010. The average annual expense reduction of $30 million the previous $20 million plus the new $10 million are to continue through 2014. On March 18, we filed with the ACC a report stating we had identified annualized cost reductions of $25.9 million. Jim will discuss the cost reduction filing in a bit more detail.

Finally, APS is to obtain a total of at least $700 million of equity infusions in the five-year period from the date of this definitive settlement agreement as filed through 2014. The parties have agreed to the parameters for APS' filing of its next two general rate cases as summarized on slide eight. APS may file general based rate requests on or after June 1st of 2011 and June 1st of 2013. A based rate increase resulting from APS' next rate case may not become effective before July 1st of 2012. And the settling parties intend to process future cases within 12 months of sufficiency findings by the ACC staff. Those are the major provisions of the proposed settlement as outlined in the term sheet we filed yesterday.

As shown on slide nine, the parties have indicated the definitive settlement agreement will be filed on June 12. We have asked the ACC administrative law judge to establish a procedural schedule requiring filing of initial testimony by the supporting parties by July 1st with additional testimony by supporting an opposing party in late July and early August, culminating with a hearing beginning August 17th. We expect the procedural order from the ALJ in the very near future.

Under this schedule, it is likely that the ALJ could issue a recommendation and turn the case over to the ACC commissioners for their consideration sometime in the early fourth quarter of this year, thus allowing for a commission decision which would permit new rates to become effective on January 1st of 2010 as proposed.

Next, I'll discuss our restructuring plan for SunCor. We reviewed SunCor's strategies, market, and the assets because of current distress conditions in the real state and the credit markets. Our expectation of such conditions will continue for some time and conditions imposed by SunCor's banks while reviewing, excuse me – renewing an existing SunCor credit facility in early 2009.

Based on the results of the reviews, the SunCor board of directors decided in the late march to restructure SunCor by completing a series of strategic transactions, to dispose of a majority of SunCor's assets and as a result to reduce it's outstanding debts. Through the restructuring, SunCor will sell its home building operations, master plan communities,

and golf courses. We currently plan to complete the asset sales in 2009. The sale proceeds will be used to pay down SunCor's debt substantially eliminating it by the end of the program.

SunCor currently plans to retain commercial assets at its Hayden Ferry Lakeside project in Tempe, Arizona. And about 2000 acres of commercial land at its Palm Valley project in the Western Phoenix metropolitan area. Execution of this strategic restructuring plan will provide a number of benefits, which include maximizing the value of SunCor's remaining assets, allowing SunCor to focus on key real state segments in the Phoenix area; substantially eliminating SunCor's outstanding debts producing at least $80million of cash tax benefits; and last but not least, eliminating real estate earnings (inaudible) for Pinnacle West. Jim will discuss the financial impacts of the SunCor's restructuring plan.

Turning to operating performance, Palo Verde continues to pose very solid performance. The nuclear units ran at full power throughout the first quarter of this year, compared with a 92% site capacity factor in last year's first quarter. Regarding Palo Verde refueling outages, there are two each year. Unit three is currently in a refueling outage, which is scheduled for completion in mid May with a duration of 40 to 50 days.

This fall, unit two is scheduled for an outage of about 60 days, which will be the first outage during which we will replace a unit's reactor, excuse me – reactor vessel head and install a new rapid refueling package. We plan to make similar improvements in the other two units in 2010.

The NRC has formally recognized Palo Verde's significant operational improvements. On March 24th, the agency cleared the confirmatory action letter and moved unit three to column one from column four of the NRC's reactor oversight matrix. Thus returning Palo Verde to routine inspection levels and ending the heightened scrutiny under which the plant has been operating. Randy Edington and his team have done a tremendous job of improving Palo Verde's performance.

Our focus is safe, long term, sustainable first quarter performance in all aspects of Palo Verde's operations. We have established five-year targets to consistently achieved 88% site average capacity factors, 30-day refueling outages, and production cost under $0.02 per kilo watt hour. Certainly, clearing the confirmatory action letter and returning the column one in the shortest time ever for any nuclear facility were very important steps in achieving our long term goal.

Our coal fire plants continue to operate superbly. In the first quarter, the coal plants posted a 78% capacity factor, which was comparable with their performance in the first quarter a year ago. And ahead of the latest available industry average of 75%. In the first quarter of both years, the capacity factors largely reflect normal seasonal overhauls and maintenance.

Now, I'll turn the call over to Jim, who'll cover our earnings and other financial updates. Jim?

Jim Hatfield

Thank you, Don. Today, the five topics I would like to touch upon as showed on slide 11 are, first quarter results; the financial impacts of the SunCor restructuring plan to which Don referred; earnings outlook for both 2009 and more importantly, 2010; our current liquidity situation; and, the common dividend level.

First, beginning with the first quarter results on slide 12. We reported, on a GAAP basis, a consolidated net loss attributable to common share holders of $156.5 million or $1.55 per share in the first quarter of 2009 as compared to net loss of $4 million or $0.04 per share in 2008's first quarter. Earnings were down primarily due to the real state impairment and related charges recorded in this year's first quarter as well as lower results in APS. I'll cover SunCor's restructuring from a financial perspective later.

Excluding the real state impairment related charges, we recorded, on an on going basis, a net loss of $29 million or $0.29 per share in this year's first quarter as compared to a net loss of $4 million or $0.04 per share for the same period in 2009. On slide 13, as a reconciliation of our GAAP earnings to our ongoing earnings per share. The reconciliation is also available in the body of the earnings release and on our web site.

A couple of comments on the reconciliation before we move on. First, the difference with turning report and ongoing earnings, as you can see on the slide relates totally to SunCor. Second, we expect a majority of SunCor's operations to move in to discontinued operations beginning in the second quarter. This will move most of the SunCor s out of ongoing results and therefore reduced the drag on ongoing earnings.

Moving on to slide 14, we'll begin the discussion of earnings with a look at year-to-year variations to our ongoing earnings per share. You can see the major drivers were gross margin at APS was off $0.09 per share. I'll provide some detail on gross margin on the next few slides.

Marketing and trading contributions were off $0.04 per share due to the expiration of our large wholesale contract in 2008. This was a contract entered into earlier in the decade. To clarify, we have not been actively pursuing marketing and trading for some time. O&M expense is lower in this year's quarter to the tune of $0.01 per share. This is primarily due to lower levels of expenses across the board, partially off set by higher expenses in fossil generation related to planned outages at units. This is net of RES related expenses, which are collected at surcharge.

Expenses related to our capital program, which includes infrastructure additions and improvements are up approximately $0.07 per share in this year's quarter. The expenses are primarily depreciation, property tax, and interest. Other expenses net of other income increased $0.04 per share in this year's quarter. And lastly, you can see the $0.02 miscellaneous items net at the bottom of the chart. If you add all of that up, you can see all you can see the components of the $0.25 per share ongoing earnings variance.

On slide 15, you see the drivers of gross margin variances in the first quarter 2009 as compared to the first quarter of 2008. This also excludes the impact of RES as previously mentioned.

On slide 14, APS' gross margins were down by $0.09 on a comparative basis from the first quarter of 2008. On the positive side, we have the benefits of the pretax $65.2 million interim decision, which was effective with the first billion-cycle in 2009. The impact of that in the first quarter was $0.80 per share. Additionally, we have the transmission rate increase by perk of our formula rates in the subsequent operation of our retail transmission cost adjuster, which improved gross margins by $0.04 per share.

Conversely, with the precipitous drop in natural gas prices, we had a non-cash mark-to-market valuation of APS' fuel and purchase powering hedges, net of the PSA deferrals at $0.12 per share on a comparative basis from last year. We had a small negative mark-to-market in this year's final quarter of $0.03 per share, compared with a large positive mark-to-market gate of $0.09 per share in 2008 first quarter consistent with the large run up of natural gas in the first half of 2008.

Milder weather and lower cost per usage combined for a $0.10 detriment to the first quarter of 2009. I use the two categories together for a reason because it's sometimes hard to distinguish what is weather and what is usage patterns in shoulder periods.

Slide 16 shows that this year's first quarter was a second mildest on record beaten only by 2003. Pitting the grid A's recorded, a proxy for weather temperature in the first quarter was 383 as compared to a ten-year average of 571 or 33% pure heating degree days in normal. As importantly, variations in the weather day-to-day were volatile so pure weather statistics based on averages may not completely capture the weather impact.

Back to the gross margin drivers on slide 17, I want to address lower costumer usage column. APS' costumer based increased a modest 0.8% in this year's first quarter, compared with a 0.2% increase in 2008's first quarter. However, whether normalized usage was down lowering gross margin by $0.02 per share.

We believe this downturn in costumer consumption likely will be short lived and has more to do with extremely mild weather conditions than people's pocketbooks. As stated earlier, during the first quarter, Phoenix had a particularly mild weather with an average temperature of 62 degrees. We have seen nothing that would indicate a change in costumer consumption habits at this point.

Looking forward, we continue to expect moderate growth over the next couple of years, albeit on a slower rate than historical averages. We still expect 1% costumer growth in 2009 through 2011. And as we've said on past calls, over the longer term, we remain confident of the fundamental – fundamentals of Arizona's feature. And expect to see costumer growth return to stronger levels as the national and state economic environments improve.

On slide 18, I want to discuss briefly the financial impacts of the second quarter restructuring process that Don discussed earlier. As a result of the Board agreeing to a plan to the invest assets to pay off bank debt, we recorded a non-cash impairment charge of approximately $202 million pretax or $1.22 per share in this year's first quarter.

Additionally, SunCor recorded other impairment charges of approximately $8 million pretax or $0.04 per share. The execution of the plan is to be kicked-off later this week for a majority of the assets. We intend to apply the proceeds

from the asset sales in the associated tax benefits, which we expect to be approximately $80 million to accelerate repayment of SunCor's debt.

As we mentioned in the last call, SunCor's security revolver requires SunCor to reduce outstanding borrowings at date certain through August 2010. As of March 31st, SunCor had approximately $175 million of total long term debt of which approaching $108 million was outstanding under the revolver. SunCor is discussing with the banks – with the banks in the revolver our waiver so they can execute the sales process. Please keep in mind that there is no cross to faults or any other ties to Pinnacle West or APS with the SunCor debt.

When we are down with the process at the end of 2009, the ongoing pretax G&A burn at SunCor will be substantially reduced from the $44 million recorded in 2008 and future real estate volatility will be eliminated for Pinnacle West shareholders.

As to earnings guidance, which is addressed on slide 19, we are reaffirming 2009 and 2010 guidance at reasonable ranges around $2.30 and $3 per share, respectively. The key assumptions for 2009 include the following, SunCor is not a material component for this year because the majority of the real estate operations will be recorded as discontinued operations beginning in the second quarter. The current interim base rate surcharge will remain in effect throughout 2009. In the effects of milder weather are all set throughout the year with cost savings identified in our filing with the ATC in March.

The key assumptions for 2010 include the following, rate settlements implemented 1/1/2010 and the identified cost savings are included. Further details reconciled in our 2008 results for 2009 and 2010 estimates are available on our Web site and in the 10-K we filed this morning.

I want to provide a quick update of our liquidity as of March 31, 2009 as shown on slide 20. We did complete a $500 million unsecured note offering in late February, which has greatly benefited our overall liquidity position. Simply stated, we have ample liquidity to execute on our capital programs. At quarter end, we had about $760 million of available credit capacity after considering short term debt levels and cash on hand. Additionally, we have no maturities of long term debt outside the SunCor until 2011. In terms of equity, we see no need to issue until 2010.

In closing, on slide 21, you see the yield of Pinnacle West common stock compared to the electric utility average. We remain committed to the common dividend, which is currently $2.10 per share annually. We are keenly aware that it is very important to our investors, provides an attractive yield, and is an important part of the value proposition.

That concludes my prepared remarks. I'll turn the call back over to Don Brandt for a wrap-up. Don?

Don Brandt

Thanks, Jim. In summary, our organization is intensely focused on operational excellence as well as improving earnings and financial metrics. We work hard to maintain topnotch costumer service. We continually strive to raise the bar even higher. Constantly improving efficiency and effectiveness in every facet of the company. APS' proposed rate settlement demonstrates positive improvement in Arizona's regulatory environment. However, it is critical for the settlement to be approved as proposed for APS, our customers, investors, and other stakeholders to realize the benefits of the settlement. The SunCor restructuring plant optimizes the assets and related financial results while minimizing risk going forward.

And finally, our current common dividend is supported by our strategies, operations, and the retail rate settlement. Overall, our employees possess a drive for excellence to improve value for our shareholders, our costumers, and the communities we serve. That concludes our prepared remarks. Jamal, at this time we would be pleased to take any questions.

Question-and-Answer Session

Operator

Yes, sir. (Operator instructions) Your first question comes from the line of Greg Gordon from Citigroup. Your line is open.

Greg Gordon – Citigroup

Good afternoon.

Jim Hatfield

Hey, Greg.

Don Brandt

Hi, Greg.

Greg Gordon – Citigroup

Congratulations on the settlement. I hope the commission approves it. They should. But anyways, on the point of the settlement, a couple of questions or clarification, are there any time limits or sort of a milestones in terms of when you have to meet certain minimum equity infusion requirements between now and 2014?

Jim Hatfield

There are not, Greg. And I think, again, with all the parties together and discussing all the issues they understand that the timing needs to be left to the company to sort of address the marketplace at the appropriate time.

Greg Gordon – Citigroup

So is it still your expectation, assuming the settlements approved that you would not need to issue equity in 2009?

Jim Hatfield

That's correct.

Greg Gordon – Citigroup

Thank you. Next question is related to Palo Verde. You're currently looking for a license extension there? Where are you in the process and at what point might we hear the decision from the NRC?

Don Brandt

Greg, I believe it was in December we filed the license extension and we're looking prior ground to two-year process.

Greg Gordon – Citigroup

So it was December of '09.

Don Brandt

Eight, eight.

Greg Gordon – Citigroup

I'm sorry, December of '08. Sorry. So you wouldn't get a decision until December 2010 most likely?

Jim Hatfield

Eighteen months to two years.

Greg Gordon – Citigroup

Okay. Okay. So under the terms of the settlement, if there were a change in the depreciation expense to the – due to license extension, that wouldn't be reconciled into rates until the next base rate case?

Jim Hatfield

Correct.

Don Brandt

That's right.

Greg Gordon – Citigroup

Okay. Thank you, guys.

Don Brandt

Thank you.

Operator

Your next question or comment comes from the line of Paul Patterson from Glenrock Associates. Your line is open

Paul Patterson – Glenrock Associates

Good morning, guys.

Don Brandt

Good morning, Paul.

Paul Patterson – Glenrock Associates

Just to go over in the settlement here. You've got the additional $23 million from SEAC going to revenues, correct, on top of the $196 million?

Don Brandt

Correct.

Paul Patterson – Glenrock Associates

Okay. And there's another $30 million in terms of savings that you guys are going to be able to have – when I've read the settlement, it seems that it was not included in the $196 million calculation.

Jim Hatfield

That would be correct.

Rebecca Hickman

Paul,–

Don Brandt

$10 million in incremental from what we've already reported to the commission.

Paul Patterson – Glenrock Associates

Okay. So we should think about it as more of the $10 million incremental as opposed the $30 million?

Don Brandt

Correct.

Paul Patterson – Glenrock Associates

Okay. And then going back to the $700 million of – one final thing on the settlement, the 54% equity ratio, is that what we should be thinking about here?

Don Brandt

Yes.

Paul Patterson – Glenrock Associates

Okay. And then the $700 million equity issuance or equity infusion, what timing do we have associated with this – I know you guys have flexibility on this, but when we look at the 2010 guidance what shall we be thinking about with respect to that?

Jim Hatfield

Well, I think we addressed this on the last call. Again, based on the schedule of getting the order, we don't anticipate the need to issue equity until any earlier than sometime in 2010. I think in our $3 guidance, we have about $0.07 to $0.075 to $0.08 of dilution based on a new equity issuance. And we'd just for simplicity made the assumption as the middle of the year, just to make our math easy. And going forward from there, based on return-to-normal growth, I support that we'll have to issue equity on a periodic basis just to support the capital structure anyways. So I didn't look at that provision as anything that we wouldn't have to do to maintain the credit ratings anyway.

Paul Patterson – Glenrock Associates

Okay.

Jim Hatfield

Whether its 700 or not, who knows based on what happens in the future. But some level of equity will be needed past ten just to support your billion dollar a year CapEx program.

Paul Patterson – Glenrock Associates

Sure. Sure. And then in terms of 2010, when we look at the SunCor impact, I wasn't completely clear on the restructuring tax benefits. Does that go to the – basically to the pay down of debt, or how should we think about that benefit that shows up from the tax benefits from restructuring?

Jim Hatfield

I think our – first and foremost our goal is to get the banks paid off to allow SunCor to operate without restrictions of the bank. Beyond that, that can be used for various things. And anything after that would just be cash that can be used to run the business.

Paul Patterson – Glenrock Associates

And how much – I'm wondering if there would be – How much of that benefit – the tax benefit could we see show up like that? Outside the – or will just be part of the discontinued operation? I'm just wondering how'd that work.

Jim Hatfield

Well, I think the benefit were tagged later in the day is $80 million. But that's of course assuming sales prices and other things that we won't really know the exact amount until really at the end of 2009. And wouldn't be realized until sometime in '10 since those are 2009 calendar year, which typically you see the benefit in 2010.

Paul Patterson – Glenrock Associates

But will that be part of the discontinued operations or does that mean that as a corporation you benefit from? Do you follow me?

Don Brandt

Yes. It wouldn't be part of the discontinued operations. It'd be additional cash flow for the corporation as a whole. And during this, as Jim indicated, we expect to complete the sales processes during 2009 while the values are depressed from what they might have been. Regardless, we still expect to generate substantial cash proceeds from these transactions.

Paul Patterson – Glenrock Associates

Okay. And then marketing and trading for 2010, is that in the 2010 guidance? Is there any benefit from that?

Don Brandt

No. I mean, as we've stated earlier, we're essentially out of that business. We did have a longer term contract that rolled off at eight, so you will see in the first half of the year some sort of negative, but that's incorporated in our Q-30. But no, nothing in 2010.

Paul Patterson – Glenrock Associates

Okay. Great. Thanks a lot, guys.

Rebecca Hickman

Paul, one other thing that I want to clarify. You asked about a $196 million plus the $23 million with respect to the settlement. There's another $11 million that you need to consider. The $196 is the non-fuel based rate increases, the $11 million is the fuel-related base rate increases, and the $23 million is the estimated 2010 impact of the scheduled three or line extension collection. So that's a total of $230 million.

Paul Patterson – Glenrock Associates

I really appreciate that. Thank you.

Rebecca Hickman

Thanks.

Don Brandt

Thanks, Paul.

Operator

Your next question comes from the line of Paul Ridzon from KeyBanc. Your line is open.

Paul Ridzon – KeyBanc

Good noon or good morning. I guess wherever you are. First of all, congratulations on the settlement, it looks pretty balanced. I just have a couple of questions. There's been some noise around changing the line extension methodology to funding some of it. Where do you see that going?

Jim Hatfield

Paul, I think a couple of things on that. Obviously, that has been somewhat controversial especially in the development community. I do think the parties to the settlement know the importance of kayak and understanding – it would be very unfair to put that into the part of the settlement then take away the line extension. I think there are some things we can do around the line extension feed that would benefit people but would not hurt the impact to APS. And so I think that's where we'll ultimately end up.

Paul Ridzon – KeyBanc

And Greg Gordon asked this question, but I saw some settlement language around maintaining a 52% debt-to-Cap ratio. How much variability is there around that? Are they going to look at that every quarter and force equity or–

Don Brandt

No, no. It's really. I would look at it this way, Paul. I think it's more of an ongoing reporting requirement. And to monitor that, more obviously comfortable in the context of the settlement with meeting those provisions or we wouldn't agree to it. But again, they understand right in the business that issue of equity and timing is a decision the company has to make. And so, they'll just be watching that from the sidelines in terms of where we are according to that metric.

Paul Ridzon – KeyBanc

How do you think about in the event that we see the return very quickly of robust growth, let's hope it happens, but to what extent do you think you've kind of lock yourself out of filing to get relief on some of that. What provisions are there if any in the settlement that could kind of give you the opportunity for emergency relief?

Jim Hatfield

Well I think if you look at the timing, – our ability to file, we can't – we are not able to file any sooner than 6/1/11. So frankly, based on the settlement, we'll have the opportunity to file with 2010 past year. And frankly that's not a whole lot different than we would have anyway.

Paul Ridzon – KeyBanc

Thank you. That's pretty much status quo. I see your point.

Jim Hatfield

Yes. And I think the big thing with that tough, Paul, is certainly the staff is committed to try and process the case in 12 months. And we've talked about some things we can do try to make that happen. And so I think, from being locked out it doesn't seem to be anything significant. I think once we file again to whenever that is, I think we'll see an accelerated process on the other end.

Paul Ridzon – KeyBanc

That would be very welcomed. And then, just from a bookkeeping perspective, of the 2/30/09 guidance what have we done so far in the first quarter? How are you doing that accounting?

Jim Hatfield

I'm not sure of the question, Paul.

Paul Ridzon – KeyBanc

How much of the 2/30 is now under your belt? I just don't know what's your accounting as far as the APS' versus other pieces?

Jim Hatfield

The APS of in quarter was about a $0.15 loss.

Paul Ridzon – KeyBanc

So basically, relative to 2/30 guidance were at a $0.15 loss?

Jim Hatfield

Right but –

Paul Ridzon – KeyBanc

Okay. Understood. Thank you.

Jim Hatfield

I don't think that the loss unexpected based on where we headed into the year.

Paul Ridzon – KeyBanc

Okay. Thanks a lot.

Jim Hatfield

Yes.

Operator

Your next question or comment comes from the line of Daniel Sites [ph] from Dudek Research Group [ph]. Your line is open.

Daniel Sites – Dudek Research Group

Thanks. Just on what we're doing – following on just the previous question. You are assuming normal weather for the rest of the year, is that – or you'll recover the $0.15 loss. Is that it?

Jim Hatfield

That's correct. We have –

Daniel Sites – Dudek Research Group

And refueling schedule, do you have the sense of when refueling are taking place? Roughly?

Jim Hatfield

I'm sorry. Could you repeat that question?

Daniel Sites – Dudek Research Group

The refueling for Palo Verde. Do you have sense of the timing for that?

Jim Hatfield

Yes. We're on – we plan a 44 day outage. That such – May 17th is the expected breaker closure. All the reports we've gotten is we're on tract with that. So it looks like from a capacity and fuel perspective, knock on wood, as we've said here today, were on tract to meet our target.

Daniel Sites – Dudek Research Group

And this is – do you have another one of this for the year?

Don Brandt

No we refuel a unit because there are three units in there on the 18-month cycle. So you end up with one every spring and fall and were expecting the next unit to take it down for refueling right around the first of October of 2009.

Daniel Sites – Dudek Research Group

Okay. Okay. Because of future rate filings, since you are respected, have you changed anything in your CapEx schedule or is it the same one as the one you have presented in March?

Jim Hatfield

It's the same one that we have highlighted March at this point.

Daniel Sites – Dudek Research Group

Okay.

Jim Hatfield

Obviously we look to adjust that going forward, it will be definitive upon growth and other thing that we see in the service territory.

Daniel Sites – Dudek Research Group

Okay. But you haven't – For the time being no change.

Jim Hatfield

Correct.

Daniel Sites – Dudek Research Group

Great. And just to – Maybe I missed it, on which debt will be left on SunCor when you're done with your program at this point?

Jim Hatfield

Our expectation is there'll be no debt at SunCor when we're through with the asset divestitures.

Daniel Sites – Dudek Research Group

Okay. Great. Thanks a lot.

Jim Hatfield

Thanks.

Operator

Your next question comes from the line of Kevin Fallon from Blenheim Capital Management. Your line is open.

Kevin Fallon – Blenheim Capital Management

Good morning. Just a couple of questions on the settlement. In particular, I'm trying to understand on the $700 million in equity infusions. Are you guys required to put from the parent down into the sub $700 million of cash or do you retain the earnings or anything like that get calculate into that or get calculated against that figure?

Jim Hatfield

Well I think the expectation of the party that's not sort of retain the earnings you keep in the business, but I think most importantly, as we look out in a lot of the filing we're doing and the monitoring has to do with where are we FFO to debt, and where are the credit metrics that sort of thing. Obviously, you get a three great weather years in a row. And you don't need to issue equity. I don't think that's the intent of the same issue equity when it's not needed.

Kevin Fallon – Blenheim Capital Management

But it doesn't require you to issue $700 million worth of new equity or debt at a parent level and put it down. Is that correct?

Jim Hatfield

That's correct.

Kevin Fallon – Blenheim Capital Management

Okay. And in terms of the dividend from Arizona public service to the parent, you guys have paid a $170 million a year for the last couple of years. Does the settlement allow you to increase that payment up to the parent now?

Jim Hatfield

Yes. There's a restriction on dividend after 2009.

Kevin Fallon – Blenheim Capital Management

After 2009, you can set it to whatever you need?

Jim Hatfield

Yes.

Kevin Fallon – Blenheim Capital Management

And in terms of the SunCor to $80 million tax gain that's going to be realized in counting your 2010 to actual cash?

Jim Hatfield

That's correct.

Kevin Fallon – Blenheim Capital Management

And it's $80 million of cash? It's not a tax affected $80 million.

Jim Hatfield

That's correct.

Kevin Fallon – Blenheim Capital Management

And under the settlement, the transmission hikes that you get for your for formula rates, are those incremental to whatever you get in the settlement here?

Jim Hatfield

Correct.

Kevin Fallon – Blenheim Capital Management

And does this settlement allow for the automatic pass through on the retail section? Or do you have to go and seek recovery in the process you currently do?

Jim Hatfield

Well, I think we're going to have to go to the process that we've gone through the past, but if you remember sort of the 2007 and 2008, it was pretty perfunctory process at the commission.

Kevin Fallon – Blenheim Capital Management

That's right. But there's nothing – in other words, they stay out or what have you in no way should have perform precludes the deferred hikes?

Jim Hatfield

Correct.

Kevin Fallon – Blenheim Capital Management

Okay.

Don Brandt

And all the other surcharges will go on at sort of normal.

Kevin Fallon – Blenheim Capital Management

And the $11 million of the net fuel related increase that just basically increased in the fuel component in based rate. Is that a earnings impact or is that a cash flow impact?

Rebecca Hickman

Tax earnings–

Jim Hatfield

That's a pretax earnings impact.

Kevin Fallon – Blenheim Capital Management

So, earnings are actually increased by pretax so $11 million I think it was. Excellent, thank you very much.

Jim Hatfield

Thank you, Kevin.

Operator

Your next question comes from the line of Andrew Levy from Incremental Capital. Your line is open.

Andrew Levy – Incremental Capital

Hey, guys. I guess you saved $3 in 010, assuming you get the full ratings or not the full ratings but the full settlement which you probably will. As you look in the 2011, I know you're not making a forecast for 2011, but everything else equal – are you able to grow earnings off to 2010 based? Or you're not sure or –?

Jim Hatfield

Andrew, we're not going to talk about guidance for 2011 today.

Andrew Levy – Incremental Capital

Yes. I understand the guidance, but can you grow earnings on the next couple of years with this settlement? Of you $3 based or not?

Jim Hatfield

We're just not going to go in this to 2011 today. I mean, if I were to indicate one way or another, that's effectively guidance, and I can't do that today.

Andrew Levy – Incremental Capital

Okay. Thank you.

Operator

Your next question comes from the line Reza Hatefi from Decade. Your line is open.

Reza Hatefi – Decade

Thank you. I just wanted to confirm an earlier question. The $700 million of equity, that's just infusion into the utility, but otherwise, you can still continue with your normal $170 million out flow from the utility to the parent level. Correct?

Jim Hatfield

That's correct.

Reza Hatefi – Decade

Okay, great. Thank you very much.

Don Brandt

Okay, Reza. Thanks.

Operator

Your next question comes from the line of Chris Shelton from Millennium. Your line is open.

Don Brandt

Chris, are you there?

Operator

Mister Shelton, your line is open.

Chris Shelton – Millennium

Hello.

Jim Hatfield

Hey, Chris.

Chris Shelton – Millennium

Can you hear me now?

Jim Hatfield

Yes.

Chris Shelton – Millennium

Sorry, I was on mute. I have a quick question on the expense savings that are ear marked in the settlement. And I know, for the following deed for the commission this year, some of those incentives were capitalized and some were extent. Is that the plan for $150 million over the five-years or there's more kind of expense savings?

Jim Hatfield

Well its expense – let's go back. The $20 million was expense which could be reduction of capital, working capital, O&M, and the $30 million is no different in characterization from the 20.

Chris Shelton – Millennium

Okay, so kind of all income statements affecting?

Jim Hatfield

Sure. Yes.

Chris Shelton – Millennium

Okay. And then, I guess the second thing – in the past, you guys had kind of been running pretty mean at the utility, I think on the cost side. And I'm sure it's where you guys are thinking you can really make an effort to control cost going forward.

Jim Hatfield

Let me give Don Robinson a chance to talk here.

Chris Shelton – Millennium

Okay. Perfect.

Don Robinson

They always give me the fun ones. We're actually looking at all of the cost here. We have run very lean and we'll continue to do that. We're going to look at improving some of the efficiency that we do have in some of the operating areas of the plant, our plants as well as the operational areas. And we're going to look at reducing some of our back office cost.

Don Brandt

Yes. We'll say this, Chris, back to your point. We follow statistics. We follow fossil capacity factors, customer sat, reliability, O&M per customer and then customers per employee. Those last few statistics show us very favorably. Our own imprecated DH [ph] is lower than the average in the Western state, customers per employee continues to rise. That said, we're going to continue on our – for – it's really about efficiency and productivity, and we'll continue to try overturn stones, to try to find where there maybe some opportunity.

Chris Shelton – Millennium

Got you. So maybe some opportunities going forward that you may not have in the past, I guess – well I guess that's it. Thanks, guys.

Don Brandt

Thank you.

Operator

(Operator instructions) At this time, there are no further questions on queue.

Don Brandt

Okay. Well let me just extend a very sincere thank you for all of your time today. And obviously, if you have any questions, give any of us a call. We would be happy to talk to you, and have a great day.

Operator

This concludes today's conference call. You may now disconnect.

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Pinnacle West Capital Corporation Q2 2009 Earnings Call Transcript

August 04, 2009 | about: PNW

Pinnacle West Capital Corporation (PNW)

Q2 2009 Earnings Call

August 4, 2009 12:00 pm ET

Executives

Rebecca Hickman – Director, IR

Jim Hatfield – SVP and CFO

Don Brandt – Chairman and CEO

Don Robinson – President and COO of APS

Analysts

Paul Ridzon - Keybanc Capital Markets

Greg Gordon - Morgan Stanley

Daniele Seitz - Dudack Research Group

Paul Patterson - Glenrock Associates

[Tom O'Neill] - Green Arrow

Chris Shelton - Millennium Partners

[Vedula Merti - CDP US]

Presentation

Operator

Good afternoon. My name is Sarah and I will be your conference operator today.

At this time I'd like to welcome everyone to the second quarter 2009 earnings conference call. (Operator Instructions)

Ms. Hickman, you may begin your conference.

Rebecca Hickman

Thank you, [Sarah].

I'd like to thank everyone for participating in this conference call to review our second quarter earnings, recent developments and operating performance. We know today is an especially busy day for you, with a number of conference calls.

Our speakers today will be our Chairman and CEO, Don Brandt, and our CFO, Jim Hatfield. Don Robinson, who is President and Chief Operating Officer of APS, is also here with us.

Before I turn the call over to our speakers I need to cover a few details with you.

First, I encourage you to check the quarterly earnings and statistics section of our website. It contains extensive supplemental information on our earnings variances and quarterly operating statistics.

Second, please note that all of our references to per share amounts will be after income taxes and based on diluted shares outstanding.

Third, we will be referring to slides today during this conference call and webcast. The slides are available on our Investor Relations website, with the webcast and with the Form 8-K filed this morning. During our prepared remarks we will give you verbal cues as we move through the slides.

Looking at Slide 2, it is my responsibility to advise you that this call and our slides contain forward-looking statements based on current expectations and the company assumes no obligation to update these statements. Because actual results may differ materially from expectations, we caution you not to place undue reliance on these statements. Please refer to the Forward-Looking Statements and the MD&A sections contained in our second quarter 2009 Form 10-Q, which was filed with the SEC this morning, as well as the Risk Factors section of our 2008 Form 10-K, all of which identify important factors that could cause actual results to differ materially from those contained in our forward-looking statements.

Next, during this call we will discuss certain non-GAAP financial measures. Our press release, the slides accompanying this webcast, and our filings with the SEC, all of which are posted on our Investor Relations website, contain additional disclosures regarding these non-GAAP measures, including reconciliations of these measures to the most comparable GAAP measures.

A replay of this call will be available on our website, www.pinnaclewest.com, for the next 30 days. It will also be available by telephone through August 11th.

Finally, this call and webcast are the property of Pinnacle West Capital Corporation and any copying, transcription, redistribution, retransmission or rebroadcast of this call, in whole or in part, without Pinnacle West's written consent is prohibited.

At this point I'll turn the call over to Jim.

Jim Hatfield

Thank you, Becky.

As shown on Slide 3, the topics I will cover today are: The second quarter results for Pinnacle West and the main variances to 2008's second quarter, our earnings outlook for 2009 and 2010, and I want to briefly update you on our liquidity situation.

Beginning on Slide 4 with second quarter results, we reported on a GAAP basis consolidated net income attributable to common shareholders of $68 million or $0.68 per share in this year's second quarter as compared with $134 million or $1.33 per share in 2008's second quarter.

I plan to focus my remarks on our ongoing earnings, which exclude results from the Real Estate segment for both quarters, as well as a $30 million second quarter 2008 income tax credit related to prior years.

Consolidated ongoing earnings in the second quarter, a non-GAAP measure, were $77 million or $0.77 per share, compared with $89 million or $0.88 per share in the prior year period.

A reconciliation of our GAAP earnings per share to our ongoing earnings per share is available on Slide 5. We've excluded the Real Estate segment from our ongoing earnings because of the major restructuring under way at SunCor and the implications for that business moving forward. We still expect a substantial majority of SunCor to move into discontinued operations for financial reporting purposes this year. Ultimately we expect the restructuring to be complete around the end of this year as execution of this plan is under way. Don will provide a brief update on the SunCor restructuring in a few moments.

Moving to Slide 6, the variances that made up the ongoing earnings per share reduction of $0.11 per share were as follows: First, miscellaneous items added $0.04 per share; the lack of investment losses in this year's quarter and other miscellaneous items increased results by $0.06; however, this was partially offset by lower Marketing and Training gross margins, a business that is no longer active. As many of you are aware, we have not been actively pursuing Marketing and Training for some time. The last two major contracts, which were negotiated earlier this decade, rolled off in 2008. This reduced gross margins by $0.02 per share.

Moving on to the Utility business, our regulated electricity gross margin's APS were up $0.02 per share. Embedded in this variance are several plusses and minuses, which I'll cover in more detail on the next slide.

O&M expense was up $0.10 per share. The increase was primarily due to the timing of planned maintenance and overhauls at our fossil plants; however, I want to emphasize that we are on target to achieve the O&M levels embedded in our 2009 guidance. This change in O&M excludes expenses related to the renewable energy standard or RES and are our demand-side management and energy efficiency programs. These costs are offset through respective rate surcharges. You may find it helpful to refer to the appendix in today's slides to find the amount of RES and DSM revenues recorded by quarter over the last couple of years.

And lastly, expenses related to infrastructure additions and improvements were up approximately $0.07 per share in this year's quarter. Interest net of capitalized financing costs and depreciation were the primarily contributing factors.

Turning to Slide 7 and the drivers of the net increase in regulated electricity gross margin, the regulated gross margin was up $0.02 on a comparative basis from the second quarter a year ago. In terms of positive contributions, we had the benefit of the interim rate decision, which became effective at the beginning of this year. This increase had a favorable impact of $0.10 per share or $16 million on a pre-tax basis. The timing of transmission rate increases associated with our formula rates and the subsequent operation of our retail transmission cost adjuster improved gross margin by $0.02 per share or $3 million on a pre-tax basis.

Lastly, weather affects added $0.07 per share. This year's second quarter was relatively normal on average, but contained a number of swings since May was hotter than normal. But most importantly June was cooler than normal. However, 2008's second quarter was much cooler [break in audio] energy efficiency efforts already under way. We are not seeing a change in customer usage in the residential class.

Looking forward we continue to expect customer growth to average about 1% annually from 2009 through 2011. Additionally, we currently expect weather-normalized retail sales to be relatively flat from 2009 through 2011 on a year-over-year comparison due to the effects of the national economy, the housing situation in Arizona, and APS's energy efficiency program. All of this is reflected in our 2009 and 2010 guidance.

In the near term the Arizona economy still has to deal with a substantial excess inventory of homes and apartments which must be reduced in order to allow sustained recovery in construction and the broader economy. This is the principal reason for our moderate outlook on near-term growth. Over the longer term we remain confident of Arizona's fundamentals and expect customer growth and usage to return to stronger levels as the national and state economic environments improve.

Returning to the variances, our net cash marked-to-market valuation of APS's fuel and purchased power hedges net of PSA deferrals was lower by $0.05 per share. Specifically, we had a relatively small positive marked-to-market in this year's second quarter of $0.03 per share compared with a large positive marked-to-market of $0.08 per share in last year's second quarter, which was driven by the dramatic run up of natural gas in the first half of 2008. For your

reference we have included our marked-to-market amounts by quarter for the past couple of years in the slide appendix.

Lastly, a few miscellaneous factors made up the remaining $0.04 of the variance.

Turning to our earnings outlook on Slide 8, we are reaffirming earnings guidance for 2009 and 2010. We continue to expect that our earnings for 2009 will be within a reasonable range around $2.30 per share and in 2010 we continue to estimate that our consolidated earnings will be within a reasonable range around $3.00 per share. This projection reflects implementation of the retail rate settlement that's currently proposed effective January 1, 2010. Further detail reconciling our 2008 results to our 2009 estimates and our 2009 estimates to 2010 guidance is available on our website and in the 8-K we filed this morning.

Lastly, although I don't have a slide, I want to give you a quick update on our liquidity. At Pinnacle West and APS we have adequate liquidity. We have previously demonstrated that in prior calls. On June 30th Pinnacle West and APS collectively had about $765 million in available cash and available credit capacity after considering short-term debt outstanding and cash on hand.

We have completed our planned refinancings for 2009. In May and June of this year we refinanced $343 million of auction rate pollution control bonds. These new bonds have a fixed interest rate with initial terms of three to seven years. We do not now have any auction rate securities outstanding.

Additionally, we have no long-term debt maturities outside of SunCor until 2011 and or revolving lines of credit mature in late 2010 and 2011.

That concludes my prepared remarks. I'll turn the call over to Don.

Don Brandt

Thanks, Jim, and thank you all for spending time with us this morning on this call.

Today I'll discuss several issues that I believe are at the top of investors' minds. Jim's already touched on our intrinsic growth and the Arizona economy. I'll update you on these items: The pending rate settlement, our renewable resource announcements, our recent operating performance, the SunCor restructuring, and my key priorities as the company's Chief Executive Officer.

Regarding our pending retail rate settlement, APS's proposed settlement demonstrates positive movement in Arizona's regulatory environment; however, it is critical for this settlement to be approved as proposed so that our customers, investors, APS and other stakeholders may realize the settlement's benefits.

The terms of the settlement were released just before our last earnings conference call. The definitive agreement is supported by 22 of the 24 parties to the rate case. Only one party filed opposing testimony and that testimony was limited to objections to the lack of free footage allowances in APS's line extension policy as it was approved by the Arizona Corporation Commission in 2008.

The settlement offers a wide variety of benefits for our customers, our communities and other Arizona stakeholders. From an investor's perspective, the primary benefits of the settlement are as follows:

First, the settlement strengthens APS's financial position, supports the current common dividend, and improves APS's ability to attract capital for infrastructure additions needed to sustain Arizona's energy future.

Second, it provides a greater level of cost recovery and return on investment for APS while providing a measure of rate stability for our customers. We estimate that approval of the settlement as proposed would improve APS's earned return on equity to between 9% and 9.5% in 2010, up from about 7% in 2009. The earned return will still be well below the 11% allowed ROE included in the settlement and we will continue to work to close that gap.

Third, the proposed settlement demonstrates a high level of cooperation among APS, the ACC staff, and other interveners which we see as a distinct positive.

Fourth, completing the settlement also will allow the opportunity for us to help shape Arizona's energy future outside

continual rate cases through dialogues and workshops with the ACC Commissions, the ACC staff, and various other stakeholders.

And finally, in a significant move to decrease the time it takes to process future rate filings, the settlement supports process efficiencies that will streamline how future APS rate cases are managed and the parties intend to use good faith efforts to process future APS rate cases more quickly. In addition, the next APS general base rate request may be filed on or after June 1, 2011 with any rate changes to go into effect on or after July 1, 2012.

On our last call I described the major financial provisions of the settlement. In summary, the settlement provides incremental revenues totaling $230 million in 2010. It also includes provisions that help stabilize APS's financial condition until the next rate case decision. Rather than prepare remarks on those details again, we've outlined them on Slides 16 through 20 in the appendix section of our quarterly slides. We will be pleased to answer any questions you may have regarding the settlement terms during the Q&A session.

The next key event on the procedural schedule is the hearing which will begin on August 19th. The full procedural schedule is outlined on a slide in the appendix. Under this schedule it is possible for the administrative law judge to issue her recommendation and turn the case over to the ACC Commissioners for their consideration some time during this year's fourth quarter. Consequently, new rates could become effective on January 1, 2010 as proposed in the settlement.

Also on the regulatory front we have implemented transmission rate adjustments. In accordance with FERC formula rates, APS's annual transmission revenues increased by $23 million effective June 1 of this year. Of that amount $21 million relates to transmission charges for retail customers. Last week the Arizona Corporation Commission approved an increase in the transmission cost adjuster - or, as we call it, TCA - to adjust retail rates for the new transmission rates beginning in early August.

Now turning to our resource acquisition and operations, we've added significantly to our renewable resource portfolio during the quarter. On May 22nd APS announced a utility scale solar plant - Starwood Solar 1. The plant will be a 290 megawatt facility about 75 miles west of Phoenix. Starwood Solar 1 will be developed and built by Starwood Energy Group and Lockheed Martin. With Starwood Solar 1 and the previously announced Solana generating station and other contractual commitments, APS expects to have 800 megawatts of energy in its renewable energy portfolio by 2013, enough energy for nearly one quarter of a million customers.

Solana and Starwood Solar 1 also will help APS provide more solar electricity per customer than any utility in the country, and they will also allow the company to exceed the requirements of the renewable energy standard established by the Arizona Corporation Commission.

Earlier in May we announced a proposed community power project in Flagstaff, Arizona, about 140 miles north of Phoenix, and completed installation of a solar system at the Grand Canyon Visitors Center.

In Flagstaff, through a distributed solar project, APS would own and receive the energy from solar panels installed on about 300 customers' rooftops and will integrate that system with a smart grid pilot project.

At the Grand Canyon, 84 solar panels are now operational and provide enough energy to offset 30% of the Canyon Visitors Center's electricity use.

Looking at our operating performance for a few minutes here, our organization is intently focused on operational excellence. We are recognized for top notch customer service and continually strive to raise the bar even higher, constantly improving performance in every facet of the company.

At our power plants the Palo Verde units have been running well. The combined capacity factor for the nuclear units was 81% in the second quarter compared with 74% in the same quarter a year ago. Both periods reflect planned refueling and maintenance outages. Currently all three units are operating at full power. The Palo Verde team is doing a tremendous job improving Palo Verde's performance and we remain focused on long-term safe, sustainable, first quartile performance in all aspects of Palo Verde's operations. We're on track to meet our established five-year targets to consistently achieve 88% annual site average capacity factors, 30-day refueling outages and production costs below $0.02 per kilowatt hour.

On the fossil side of our business our coal-fired plants and our gas-fired plants are performing well, helping meet our customers' energy needs.

Regarding our customer service, last month J.D. Power and Associates released the result of its 2009 survey of residential utility customers. APS continues its record of strong performance in customer satisfaction, ranking in the top quartile nationally. More specific to our region of the country, we were rated third among the 10 largest investor-owned utilities in the West. In addition to the overall customer satisfaction index, APS ranked in the top quartile nationally in four of the six components of customer satisfaction as defined by J.D. Power. Those top quartile performance areas are power quality and reliability, customer service, communications and corporate citizenship.

Next I'll turn to the status of our SunCor restructuring plan. On our last earnings call we announced a restructuring plan for SunCor that is focused on optimizing proceeds from asset sales while minimizing risk going forward and substantially eliminating SunCor's debt. Execution of this plan is under way. While operating under a forbearance agreement that expires on August 15th, SunCor is in discussions with their banks to resolve certain covenant defaults.

Looking ahead, I have previously indicated the top goals on my personal agenda as Pinnacle West's new CEO and I want to take this opportunity to reinforce these fundamental priorities: First, building superior investor and customer value; two, demanding safety as a top priority; three, maintaining operational excellence and disciplined cost management; four, building a sustainable energy future; five, building and leveraging our high performance work force; and six, promoting a culture of respect, integrity and trust.

Through commitment to an exception execution of these goals we will continue to move this company forward while helping Arizona recover economic vitality and attract new businesses and residents. Additionally, we are committed to improving our earnings and financial metrics and thereby sustaining our dividend. We are keenly aware of the vital importance of the dividend to our investors and thus to our ability to attract capital in the future.

That concludes our prepared remarks this morning. Operator, at this time we'd be pleased to take any questions.

Question-and-Answer Session

Operator

(Operator Instructions) Your first question comes from Paul Ridzon - Keybanc Capital Markets.

Paul Ridzon - Keybanc Capital Markets

One thing that we have seen is that large reductions in C&I tend to have a smaller-than-expected earnings impact because a lot of the revenues are structured more as capacity reservation. Are you less than others in that regard? I was surprised by the $0.08 degradation of earnings.

Jim Hatfield

Well, if you look at where we've had our reduction, it's really been manufacturing, 17%, warehouse, about 10%, and really retail and office and that category. In terms of contribution we saw, like I said, over 80% of that sales reduction in the C&I.

So in terms of the $0.08 degradation relative to C&I, I'm not sure the rate designs of others but our rate design is structured so that we're trying to levelize those more across the board with residential.

Don, do you have anything specific on rate design you want to add to that?

Don Brandt

I don't.

Paul Ridzon - Keybanc Capital Markets

How hot has July been?

Jim Hatfield

Well, we had the hottest July on record. We had several days in July where the average temperature was 100, so just from a relative basis, significantly above normal. I don't have degree days in front of me, Paul, but the fact that it was the hottest on record I think gives the magnitude of the heat in July. And August is sort of starting off the same as July ended up, at least through the first four or five days.

Paul Ridzon - Keybanc Capital Markets

So that should be a nice tailwind.

Jim Hatfield

Well, we're hoping.

Paul Ridzon - Keybanc Capital Markets

And then just lastly just an update on potential tapping the equity markets. Is that still a '10 event?

Jim Hatfield

Correct, no change in terms of equity plans at this point.

Operator

Your next question comes from Greg Gordon - Morgan Stanley.

Greg Gordon - Morgan Stanley

So the degradation you saw in sales, that might have been partly from weak weather in the second quarter. Would it be fair to say that the four or five weeks you've had in July and August have sort of put you back on track?

Jim Hatfield

Yes, just a couple things. You know, I talked about this at length in the first quarter, you know, the role of weather and what's usage. I can tell you that even through sort of normal weather residential sales were down 3% and humidity was 10% below normal. What's that do vis-à-vis normal? I'm not sure. But certainly July, we feel good about the 230 and about sales and don't think that anything so far is off track to achieve our numbers.

Greg Gordon - Morgan Stanley

Don, I know you're trying to keep things extremely positive when you talk about the dependency of the vote on the rate settlement, as you should. What would you guys have to do in terms of changing the financial strategy of the company to react to either a rejection of the settlement or a material modification of the settlement?

Don Brandt

Well, we're focused now on getting the settlement approved, Greg. As I mentioned, we've got 22 out of the 24 parties supporting it; only one party objecting and that's on a very limited aspect. We've had, I think, a level of spirit of cooperation in this settlement process that we have not had before. The settlement addresses a wide variety of factors other than earnings and rate issues relative to environmental aspects, renewable energy, low income customers.

I think once it's explained and reviewed by the Commission in detail the Commissioners will find it a very attractive result of the settlement process.

Operator

Your next question comes from Daniele Seitz - Dudack Research Group.

Daniele Seitz - Dudack Research Group

Could you give us some details on the cost of the solar plant and is there a special regulatory treatment for these types of plants in Arizona?

Jim Hatfield

In terms of solar, Daniele?

Daniele Seitz - Dudack Research Group

Yes, yes. And if you could give us an idea of the cost and how will you recover those costs?

Jim Hatfield

Well, the cost is confidential according to our agreements. We'll enter into PSAs with the two large ones and those will be passed through the PSA 100%.

And right now I guess I would characterize it as the state is very positive on solar. We have all the attributes for solar that you would want. We're planning on continuing to increase our renewable energy and under the framework of Arizona regulation that is passed through the PSA at 100% and through the RES.

So there's really no net costs from a shareholder perspective because that's all being recovered.

Daniele Seitz - Dudack Research Group

Okay, so it's pure purchased power cost? You're not involved in the investment?

Jim Hatfield

Correct.

Operator

Your next question comes from Paul Patterson - Glenrock Associates.

Paul Patterson - Glenrock Associates

Just on the customer growth outlook and weather-normalized sales, looking at your release if I'm reading it correctly it appears that you guys have had about 0.7 of 1% customer growth yet a decline weather normalized. And you mentioned, as you guys did previously, that you still expect 1% growth.

Jim Hatfield

In customers, that's correct.

Paul Patterson - Glenrock Associates

How shall we think about the outlook for actual kilowatt hours through this 2009 through 2011 period?

Jim Hatfield

As I said when I was talking about that issue, we're planning on flat sales year-over-year really driven by the economy as well as energy efficiency efforts.

Paul Patterson - Glenrock Associates

That's this year.

Jim Hatfield

And that would be a statement that we see it through 2011 at this point.

Paul Patterson - Glenrock Associates

Oh, really, through 2011 you don't expect any significant growth in kilowatt hour sales?

Jim Hatfield

That's correct.

Paul Patterson - Glenrock Associates

Is that because of the economy or is that efficiency? How do we think about that? I mean, that seems like a pretty less-than-robust outlook from what you guys have traditionally have.

Jim Hatfield

Well, I think you have to look at it in two ways. One of the things we're doing - and we filed this with the Commission - we're getting about 0.4 of 1% reduction in sales just through our energy efficiency efforts so far, so, for your thinking, that's where that's going.

The other is just, like we said, an economy that needs to absorb these 30,000-plus houses that are available out there before we see any meaningful pickup. From a C&I perspective the only growth year-to-date has been in hospitals and schools, which have been very modest sales growth.

So we're just seeing that pattern continue until we get back to what we believe will be more traditional growth in customers and kWh sales.

Paul Patterson - Glenrock Associates

So basically it's real estate dependent, I guess, is the way to think about the big driver in Arizona?

Jim Hatfield

It's real estate dependent and tourism driven, and that's been our drivers. We expect we'll continue to see robust growth once economic factors point to a positive direction. But keep in mind with the 30,000-plus homes here, we have a lot to absorb before we get back on that growth track.

Operator

Your next question comes from [Tom O'Neill] - Green Arrow.

Tom O'Neill - Green Arrow

I have a longer-term question just on how you're evaluating rate-based opportunities in solar. I guess A) your thoughts on that, and then B) what filing you might need to do to address the self-build moratorium that I think would keep you from that.

Don Robinson

The self-build moratorium doesn't apply to renewable resources, so we have the ability to build renewable resources and that is one of the things that we are looking at as we go forward and what should our investment in those be. And

we're evaluating different structures right now because clearly, as we go long term, we are going to be a large player in the solar development in the state and I think ownership of a portion of those plants are where we're going.

Jim, you want to anything?

Jim Hatfield

I would just say from a financial perspective we're not opposed to PPAs; however, without any ability to earn on those commitments we're seeing a negative impact to the capital structure through imputed debt and I think that's something that we have to keep in mind as we address this issue going forward.

Tom O'Neill - Green Arrow

And just along those lines, how would you envision a regulatory compact that you would get comfortable with just to avoid some of the lag problems of the past?

Jim Hatfield

I think we would go out to the Commission in the front end just like we would for any new baseload generation that we would be looking at and get an agreement from them on how we would be paying for this and when we would recover costs along the way as [WIP] or some other innovative process so we are not waiting until the end of the period to recover our total costs. We're not going to do that.

Operator

Your next question comes from Chris Shelton - Millennium Partners.

Chris Shelton - Millennium Partners

I just wanted to clarify, actually. It seems like there's a couple of moving parts in the guidance for '09. I guess you're ahead on weather - it sounds like July was pretty warm - but usage is tracking a little bit behind, and I just wanted to see which of those or if any was kind of assumed in the 230 for '09?

Jim Hatfield

I want to just clarify your first point. I don't think we're ahead on weather; I think July sort of brought us back to close the gap. As I said earlier, even though second quarter was normal it was a hot May and a cool June and we saw residential cooling degree days off 3%. So I think July just was more of a catch-up.

From a usage pattern what July told us, I mean, we understand the C&I industrial pattern and we have planned for that. July residential sales, we saw robust residential sales which is consistent with the weather pattern, so I don't think there's any real impact on usage that we're seeing today. Energy efficiency's been built into the outlook. And weather, we look at sort of normal weather over the course of the year and I think July is bringing us back to that bogey.

Chris Shelton - Millennium Partners

The usage, I guess, is tracking for flat for the year still? Is that fair?

Jim Hatfield

Usage is tracking or weather adjusted would track more toward a flat '09 over an '08.

Chris Shelton - Millennium Partners

And then also to clarify, July bringing weather back to normal, that was assumed in the 230 also, right?

Jim Hatfield

Exactly. We did get the benefit of July behind us when we looked at that.

I also want to point out there is a lot of unsold homes in the service territory and those homes count as customers although their usage is de minimis at best at this point. And that's also a factor when we look at usage, but we believe we've built all of those things into the 2009 guidance.

Chris Shelton - Millennium Partners

Don, when you were talking about not earning a 9% ROE under the settlement, do you have the rate base on the equity layer that you were assuming in that or maybe which year you were assuming?

Don Brandt

I was talking about actual reported earnings for 2010, those levels of return on equity.

Jim Hatfield

And we've provided CapEx updates for the utility as well and we're assuming a 54% equity at APS, which is consistent with the cap structure in the settlement.

Chris Shelton - Millennium Partners

Okay, so just to clarify, the rate base would be a projected 2010 rate base not the rate base in the settlement or 2009?

Jim Hatfield

Correct.

Chris Shelton - Millennium Partners

Who's objecting to the settlement at this point?

Don Brandt

Just one party relative to our line extension agreement, where the Commission two years ago changed it. There was generally a 1,000-foot free allowance for new residential development and that was eliminated.

Chris Shelton - Millennium Partners

And who's the party objecting, I guess, or is that the only objection.

Jim Hatfield

It's a group basically representing development. I don't have a name, but [Barbara Wylie] is the person whose name it is.

Chris Shelton - Millennium Partners

It's the developers, though? That makes sense.

Operator

(Operator Instructions) Your next question comes from Paul Ridzon - Keybanc Capital Markets.

Paul Ridzon - Keybanc Capital Markets

What have we seen out of the Commission as far as data points to how the new Commissioners think about the world?

Don Brandt

Relative to our case, Paul, they really haven't had an opportunity to comment on it. We have the hearings starting. I think that'll give us a reasonable perspective. Again, both in the settlement and part of the aim of the parties putting together the settlement was to address the issues that we thought were important to all the parties and to the Commission and the state as a whole and our customers, most importantly, again, besides the rate and earnings issues for APS and our investors, but also renewable energy, environmental benefits, low income assistance for customers, rate design issues. Again, I think when they have the opportunity to review with all the parties the aspects of the case they'll find it's a very attractive proposal before them.

Jim Hatfield

I think, Paul, most recently we had our implementation of the retail rates of the TCA; that was approved. That went into impact in August. That's probably the latest data point as it relates particularly to APS.

Paul Ridzon - Keybanc Capital Markets

Have there been cases outside of APS where they've looked more or less constructive than historically?

Jim Hatfield

Well, I mean, Tucson got their settlement last year. They're [inaudible]. Southwest Gas was late last year. I haven't really seen anything as it relates to a rate.

Don Robinson

They just had a rate case regarding a company called Trico that was approved in the last opening meeting, I believe.

Jim Hatfield

Right. And that was July. And that's been about it; most of the others have been more normal course - renewable energy, energy efficiency, demand-side management type programs.

Operator

Your next question comes from [Vedula Merti - CDP US].

Vedula Merti - CDP US

A couple things I just want to make sure I have clarified. The time period for the rate base that constitutes settlement is, again, which time period?

Jim Hatfield

It's 2007 with some pretty much what's in service in 2008.

Vedula Merti - CDP US

Now, the next opportunity you would have under the settlement to go in would be during I it's 2011. Is that correct?

Jim Hatfield

June 1, 2011. And we would do that on a 2010 test year, so we would pick up '09 and '10 in that timeframe.

Vedula Merti - CDP US

If one takes a look at the CapEx less DD&A and everything like that, would we be talking like somewhere in the range of about $1 billion of incremental rate base between the two periods in terms of the rate cases?

Jim Hatfield

Yes, roughly in that area. Our CapEx that we previously talked about as an estimation for '10 has not really changed and it is down from 2009.

Vedula Merti - CDP US

Okay, so then the period in which you would then be able to realize hopefully a reasonable rate of return on that incremental rate base would then be some time during 2012, 2013, so this period while you're in the reasonableness range of $3 give or take and your other cost management efforts and things of that nature to manage things, your next potential increment in terms of realizing better returns on your rate base would then become 2012 basically?

Jim Hatfield

That's correct, yes. Again, because the parties are going to use their best efforts to try to get that process in '12, which would imply potentially a mid-year 2012 increase.

Vedula Merti - CDP US

And is there any opportunity do you think as part of that process that even though you'd have a 2010 test year that things that are fairly known or measurable or significant that would be 2011 items could be reflected as well?

Jim Hatfield

It could be. It really depends upon the framework going forward, and we've talked about that before. But at this point we're looking at the schedule that's in front of us.

Operator

Your final question comes from Daniele Seitz - Dudack Research Group.

Daniele Seitz - Dudack Research Group

Could you give us update on the restructuring of SunCor? What are your goals and timing?

Jim Hatfield

Yes, great question. First of all, we stated before our goal is really to optimize the assets and to pay down debt and be left with sort of a de minimis impact from SunCor.

Where we are in the process is the Hayden Ferry Lakeside Condos is in escrow and will close this month. Homebuilding, we have LOIs and we're working that sales process; we still expect a 2009 close. Golf course bids are due on Friday; still expect a 2009 close. We have various Palm Valley partials that are in escrow or LOIs and we're still working that process for a 2009 close. And the Hayden Ferry Lakeside development project is in process at this point.

We still appear to be on track for around a year end 2009 completing the restructuring and the goal is to pay the banks down to zero. And, as we said before, there's some consolidated tax benefit.

But nothing at this point tells us that the restructuring won't be what we've planned all along in terms of sort of assets and timing and dollars.

Daniele Seitz - Dudack Research Group

And no estimates in terms of potential write-offs or anything like that?

Jim Hatfield

No, we had about $6 million of additional impairment charge in the second quarter but, like I said, everything right now is sort of meeting expectations, with some things still ahead of us to go at this point.

Operator

There are no further questions at this time.

Rebecca Hickman

Thank you, again, for joining us today. Meanwhile, if you need any additional information or further details about earnings please contact me or Lisa Malagon. This concludes our call.

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Gas Daily

Wednesday, August 19, 2009

NYMEX retreats toward $3, closes at 7-year low

THE MARKET

Despite a big rally in the oil market, the September NYMEX gas futures contract slid another 6.7 cents Tuesday to settle at $3.096/MMBtu — the lowest prompt-month close since August 14, 2002. Cash markets fell except where maintenance outages buoyed prices.

Over the past nine sessions, the contract has fallen 94.6 cents due largely to a "plethora of supply," PFGBest analyst Phil Flynn said. Despite a $2.44/barrel surge by the NYMEX crude oil contract due to

(continued on page 2)

Ex-Amaranth trader begins defense before FERC

Brian Hunter, once the top gas trader for a now-collapsed hedge fund, took the audience at a Federal Energy Regulatory Commission show-cause hearing to school Tuesday, explaining the basics of gas futures trading under questioning by FERC's lawyer.

Hunter, formerly of Amaranth Advisors, was the first witness FERC called in its prosecution of Hunter, ordering him to show why he shouldn't be fined up to $30 million for allegedly manipulating the expiration prices of the March, April and May 2006 NYMEX gas futures contracts.

(continued on page 6)

CEO: Anadarko won't cut drilling despite prices

Despite low wellhead prices that have prompted many producers to curtail drilling, Anadarko Petroleum has no plans to shut in significant volumes of North American gas, Chairman and CEO Jim Hackett told Platts on Tuesday.

Speaking on the sidelines of a Rally for Jobs and Affordable Energy in Houston, Hackett said he anticipates domestic gas prices staying around current levels until sometime next year, when they will settle into a band of $5/Mcf to $7/Mcf.

"We've actually curtailed very little production. We're just manag-

(continued on page 4)

Economy, low gas prices take toll on lease sale

Western Gulf of Mexico Lease Sale 210, scheduled for today in New Orleans, promises to be one of the least active oil and gas auctions in more than a decade, according to data released Tuesday by the Minerals Management Service.

MMS said 26 companies made 189 offers for 162 tracts off the Texas coast, compared with 53 firms making 423 bids on 319 tracts in last year's Western Sale 207.

MMS Gulf Regional Director Lars Herbst told Platts that the number of bids in Sale 210 was about in line with agency predictions given

(continued on page 4)

Daily price survey ($/MMBtu)

NATIONAL AVERAGE PRICE: 3.120

Trans. date: 8/18
Flow date(s): 8/19

	Midpoint	+/-	Absolute	Common	Volume	Deals
Permian Basin Area						
El Paso, Permian	3.005	+0.000	2.95-3.04	2.98-3.03	654	118
Waha	3.035	-0.010	3.01-3.07	3.02-3.05	119	25
Transwestern, Permian	2.920	-0.030	2.90-2.93	2.91-2.93	10	3
East Texas-North Louisiana Area						
Carthage Hub	3.080	+0.005	3.05-3.10	3.07-3.09	122	28
NGPL, Texok zone	3.055	+0.000	3.03-3.07	3.05-3.07	759	96
Tx. Eastern, ETX	3.080	+0.025	3.03-3.09	3.07-3.09	35	12
Tx. Gas, zone 1	3.095	-0.025	3.08-3.13	3.08-3.11	283	45
East-Houston-Katy						
Houston Ship Channel	3.075	+0.000	3.06-3.11	3.06-3.09	858	104
Katy	3.075	+0.000	3.06-3.11	3.06-3.09	423	63
South-Corpus Christi						
Agua Dulce Hub	3.095	+0.010	3.07-3.10	3.09-3.10	126	8
NGPL, STX	3.050	-0.025	3.04-3.06	3.05-3.06	160	29
Tennessee, zone 0	3.070	-0.025	3.05-3.08	3.06-3.08	206	41
Tx. Eastern, STX	3.070	-0.010	3.05-3.10	3.06-3.08	88	21
Transco, zone 1	3.110	-0.010	3.10-3.12	3.11-3.12	25	7
Louisiana-Onshore South						
ANR, La.	3.100	-0.035	3.08-3.13	3.09-3.11	237	46
Columbia Gulf, La.	3.100	-0.015	3.08-3.12	3.09-3.11	420	54
Columbia Gulf, mainline	3.125	-0.020	3.09-3.15	3.11-3.14	539	81
Florida Gas, zone 1	3.110	+0.050	3.11-3.11	3.11-3.11	26	5
Florida Gas, zone 2	3.125	-0.005	3.11-3.14	3.12-3.13	96	6
Florida Gas, zone 3	3.145	-0.010	3.11-3.20	3.12-3.17	346	54
Henry Hub	3.120	+0.010	3.07-3.16	3.10-3.14	875	130
NGPL, La.	3.050	-0.035	3.05-3.10	3.05-3.06	8	2
Southern Natural, La.	3.135	-0.010	3.11-3.16	3.12-3.15	434	55
Stingray Pool	—	—	——	——	—	—
Tennessee, 500 Leg	3.100	-0.030	3.07-3.13	3.09-3.12	437	81
Tennessee, 800 Leg	3.095	-0.030	3.07-3.11	3.09-3.11	448	68
Tx. Eastern, WLA	3.110	-0.010	3.07-3.13	3.10-3.13	407	65
Tx. Eastern, ELA	3.130	-0.015	3.10-3.15	3.12-3.14	267	44
Tx. Gas, zone SL	3.095	-0.025	3.08-3.11	3.09-3.10	116	18
Transco, zone 2	3.110	-0.005	3.08-3.14	3.10-3.13	112	22
Transco, zone 3	3.145	-0.005	3.12-3.18	3.13-3.16	644	92
Trunkline, WLA	3.110	-0.035	3.06-3.15	3.09-3.13	24	5
Trunkline, ELA	3.085	-0.030	3.08-3.10	3.08-3.09	86	17
Oklahoma						
ANR, Okla.	2.920	-0.040	2.91-2.93	2.92-2.93	71	13
CenterPoint, East	3.080	+0.090	3.00-3.15	3.04-3.12	130	26
NGPL, Midcontinent	2.925	-0.060	2.90-2.95	2.91-2.94	81	18
Oneok, Okla.	2.945	-0.050	2.91-2.97	2.93-2.96	48	16
Panhandle, Tx.-Okla.	2.895	-0.055	2.84-2.95	2.87-2.92	179	42
Southern Star	2.905	-0.010	2.87-2.93	2.89-2.92	72	13
New Mexico-San Juan Basin						
El Paso, Bondad	2.840	-0.005	2.84-2.85	2.84-2.84	4	2
El Paso, San Juan	2.875	+0.015	2.86-2.91	2.86-2.89	513	67
Rockies						
CIG, Rockies	2.765	-0.015	2.75-2.78	2.76-2.77	53	14

NYMEX falls for ninth straight session ... *from page 1*

economic improvements abroad, gas "is in its own little world," far more susceptible to domestic supply/demand forces than global conditions, he said.

Tim Evans, an analyst at Citi Futures Perspective, said the mid-range temperature outlook was less supportive Tuesday than it was Monday. In addition, concerns that a pair of tropical storms in the Atlantic Ocean could hit the Gulf of Mexico producing region all but subsided Tuesday as one storm dissipated and the other took a more northerly track.

In the spot market, the McMahon gas processing plant in British Columbia near Westcoast Energy's station 2 will be out of service today, and traders were scrambling to stay long at the point in case the turn-around outage goes beyond one day.

"Sometimes these turn-arounds take longer than anticipated and nobody wanted to take any chances of going short if it does," a local trader said, adding that most of the supply that hits station 2 comes from the McMahon plant.

The resulting 20-cent increase in prices widened the point's spread to AECO-NIT in Alberta to an unheard of near-20-cent premium.

In the Rockies, the White River Hub in Colorado on IntercontinentalExchange was the only point to rise about 5 cents as a hot tap weld on mainline 126 is scheduled to last through Tuesday, the pipeline said in a web site notice.

'No demand, no weather and no interest'

A lack of demand in the Southwest weakened prices. While temperatures are a bit above average in some metropolitan areas, the warmer-than-normal weather hasn't been able to trump the bearishness of the September NYMEX contract and full storage in the area, a trader said.

"There's only three issues here — no demand, no weather and no interest" in spot gas, the trader said, adding that buyers were heavy at the Pacific Gas and Electric city-gate despite expectations that linepack on the system will trend lower over the next few days.

"Nobody wants to go short in case the weather stays warm," the trader said. While buyers were more active at the PG&E city-gate and Malin, Oregon, on ICE, sellers sought to dump supplies at the Southern California Gas city-gate and prices fell to $3 late in the session.

Upper Midwest prices took a unified trek downwards, with prices dropping almost 5 cents throughout the region as weather continues to be cool in the Chicago area.

Cash prices in Michigan were weak as storage levels inched closer to record levels.

Midcontinent prices were mixed as warmer weather in Texas and maintenance issues alleviated some of the downward pressure from the NYMEX.

Scheduled maintenance has begun on Natural Gas Pipeline Co. of America's station 801 in Carter County, Oklahoma, reducing capacity there to a minimum of 46% of maximum daily quantity, but the maintenance didn't seem to affect cash prices much. CenterPoint Energy Gas Transmission East posted the only gain in the region to reach parity with the Carthage Hub.

"The only thing we have to worry about are the storage numbers. We had some heat in the Northeast that we didn't have last week, so

Daily price survey ($/MMBtu)

Trans. date: 8/18
Flow date(s): 8/19

	Midpoint	+/-	Absolute	Common	Volume	Deals
Kern River, Opal	2.770	-0.030	2.74-2.82	2.75-2.79	295	63
Stanfield, Ore.	2.815	-0.055	2.78-2.89	2.79-2.84	122	19
Questar, Rockies	2.655	-0.050	2.65-2.70	2.65-2.67	5	3
Cheyenne Hub	2.745	-0.065	2.70-2.80	2.72-2.77	133	26
NW, Wyo. Pool	2.765	-0.020	2.74-2.79	2.75-2.78	119	20
NW, s. of Green River	2.765	-0.030	2.74-2.80	2.75-2.78	43	7
Canadian Gas						
Iroquois, receipts	3.500	-0.025	3.45-3.52	3.48-3.52	121	22
Niagara	3.380	-0.045	3.35-3.41	3.37-3.40	210	29
NW, Can. bdr. (Sumas)	2.845	-0.025	2.80-2.89	2.82-2.87	84	17
TCPL Alberta, AECO-C*	C2.660	C-0.010	C2.52-2.70	C2.62-2.70	2719	237
Emerson, Viking GL	2.865	+0.000	2.84-2.89	2.85-2.88	329	34
Dawn, Ontario	3.245	-0.015	3.22-3.28	3.23-3.26	1066	146
GTN, Kingsgate	2.770	-0.060	2.73-2.82	2.75-2.79	355	29
Westcoast, station 2*	C2.810	C+0.200	C2.70-2.95	C2.75-2.87	215	39
Appalachia						
Dominion, North Point	3.370	-0.160	3.37-3.37	3.37-3.37	7	1
Dominion, South Point	3.430	-0.060	3.38-3.48	3.41-3.46	359	63
Leidy Hub	3.545	-0.085	3.50-3.60	3.52-3.57	52	8
Columbia Gas, App.	3.270	-0.030	3.23-3.32	3.25-3.29	498	88
Lebanon Hub	3.160	+0.000	3.13-3.19	3.15-3.18	589	60
Mississippi-Alabama						
Tx. Eastern, M-1 30-in.	3.200	-0.020	3.18-3.23	3.19-3.21	285	62
Transco, zone 4	3.155	+0.010	3.12-3.19	3.14-3.17	743	100
Others						
Algonquin, receipts	3.695	+0.025	3.67-3.75	3.68-3.72	21	5
El Paso, South Mainline	3.110	-0.065	3.09-3.12	3.10-3.12	246	32
SoCal Gas	3.040	-0.055	2.98-3.11	3.01-3.07	475	58
PG&E, South	3.030	-0.050	3.01-3.05	3.02-3.04	117	20
PG&E, Malin	2.925	-0.070	2.88-2.97	2.90-2.95	487	66
Alliance, into interstates	3.165	-0.025	3.08-3.20	3.14-3.20	580	77
ANR, ML 7	3.225	+0.000	3.11-3.27	3.19-3.27	192	16
NGPL, Amarillo receipt	2.985	-0.055	2.96-3.05	2.96-3.01	82	15
Northern, Ventura	3.075	-0.020	3.05-3.10	3.06-3.09	41	10
Northern, demarc	3.075	-0.035	3.04-3.10	3.06-3.09	192	35
Dracut, Mass.	—	—	—	—	—	—
Tx. Eastern, M-1 24-in.	3.100	-0.010	3.10-3.12	3.10-3.11	70	9
Northern Bdr., Ventura TP	3.080	-0.015	3.05-3.12	3.06-3.10	13	5
Trunkline, zone 1A	3.100	-0.015	3.06-3.11	3.09-3.11	66	9
Citygates						
Chicago city-gates	3.180	-0.005	3.14-3.20	3.17-3.20	508	98
Consumers city-gate	3.185	-0.035	3.17-3.20	3.18-3.19	173	41
Mich Con city-gate	3.185	-0.035	3.16-3.23	3.17-3.20	353	58
PG&E city-gate	3.320	-0.055	3.27-3.36	3.30-3.34	825	117
Florida city-gates	3.735	-0.175	3.66-3.85	3.69-3.78	139	8
Algonquin, city-gates	3.715	+0.025	3.65-3.77	3.69-3.75	474	83
Tennessee, zone 6 del.	3.645	-0.060	3.58-3.77	3.60-3.69	407	64
Iroquois, zone 2	3.685	+0.010	3.65-3.76	3.66-3.71	144	36
Tx. Eastern, M-3	3.625	-0.030	3.54-3.71	3.58-3.67	701	157
Transco, zone 5 del.	3.360	-0.110	3.32-3.45	3.33-3.39	71	12
Transco, zone 6 non-N.Y.	3.595	-0.045	3.53-3.65	3.57-3.63	195	39
Transco, zone 6 N.Y.	3.715	-0.045	3.65-3.80	3.68-3.75	561	87
Kern River, delivered	3.090	-0.025	3.02-3.10	3.07-3.10	162	24
SoCal Gas, city-gate	3.055	-0.010	3.01-3.08	3.04-3.07	321	43

***NOTE: Price in C$ per gj; C$1=US$0.9061**
Volume in 000 MMBtu/day

Market coverage

More information about Platts natural gas market coverage, including explanations of methodology and descriptions of delivery points, is available at www.platts.com/Natural Gas/Resources/Methodology & Specifications/.

Questions may also be directed to our market editors: Tom Castleman, (713) 658-3263, tom_castleman@platts.com and Liane Kucher, (202) 383-2147, liane_kucher@platts.com.

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who knows where Thursday's going to go," the trader said.

Above-average temperatures helped keep most Northeast prices at a steep premium to neighboring regions, despite sliding slightly. Prices generally fell a few cents after big gains Monday for most points in the Mid-Atlantic and New England, fueled by 90-degree temperatures.

The Algonquin Gas Transmission city-gates were the sole exception, with the point tacking on about a cent amid some maintenance issues. Most Mid-Atlantic points shed a cent or so late in the session.

Losses were a little steeper in the Appalachian region as volumes picked up with heavier flows through the Rockies Express Pipeline. Niagara also fell, as operator Tennessee Gas Pipeline announced that restrictions would be slightly lifted for meters there.

Weak fundamentals led to mixed prices along the Gulf Coast. Henry Hub was one of the few to move up, propped up by a late rally that took highs up a few cents. Slightly more seasonable temperatures in Texas and rain and lower power loads in Florida helped to tip the scale back for most other points.

Florida Gas Transmission issued an overage alert for Tuesday at 25% tolerance. — *Market Staff Reports*

Agencies dispute status of Weaver's Cove mitigation plan

Language used by Weaver's Cove Energy in its updated mitigation plan for its proposed liquefied natural gas terminal in Massachusetts has rubbed a number of regulatory agencies the wrong way, causing the company to revise its statements and at least two federal agencies to call for meetings to clarify the project's status.

In a submission to the Federal Energy Regulatory Commission made available Monday, the National Park Service disputed allegations by Weaver's Cove that new mitigation measures would "fully address" the agency's concerns about the 400,000 Mcf/d import facility planned for Fall River.

At issue is Weaver's Cove's July 20 submission to FERC of an updated mitigation plan for the terminal. In that document, the company referenced mitigation procedures linked to shoreline conditions within the Taunton River, saying that the procedures "fully address the National Park Service's stated preference for measures that would improve upon existing site conditions to ensure compatibility with the Wild and Scenic Rivers Act designation."

Ten days later, the company held its regularly scheduled monthly meeting with representatives of several state and federal agencies, including NPS and the US Environmental Protection Agency. "Much to Weaver's Cove's surprise, certain of the resource agencies took umbrage with the updated mitigation plan, believing that in certain areas it improperly characterized their position with regard to project-related impacts, alternatives to avoid such impacts, and appropriate mitigation," Weaver's Cove attorney Bruce Kiely told FERC.

"To be clear, it was not Weaver's Cove's intention to imply that there was agency 'sign-off' on these issues or to characterize the position of any party save the National Park Service, which had stated a specific preference for measures that would improve upon existing site conditions to ensure compatibility with the Wild and Scenic Rivers Act," Kiely said.

But Jamie Fosburgh, rivers program manager for NPS' Northeast Region Office in Boston, told FERC that NPS "has never intimated that addressing this single issue would in any way 'ensure compatibility' with the Wild and Scenic River designation" enacted earlier this year (*GD 3/29*).

For example, Fosburgh said, the updated mitigation plan "fails to make any mention of approximately five acres of permanent winter flounder spawning habitat loss that we understand would occur within the Taunton River in the vicinity of the proposed LNG storage facility." That impact "is of high concern" to

N.C. utility to replace three coal plants with 950-MW gas-fired facility

Progress Energy Carolinas on Tuesday said it plans to permanently close three coal-fired power plants near Goldsboro, North Carolina, and build a gas-fired plant at the site.

Under its proposal, the Raleigh, North Carolina-based utility said the new plant will increase the existing capacity of the site by about 550 MW, while reducing overall air emissions, including carbon dioxide. Progress said the additional capacity will be used to meet growing demand and to provide for "additional resource flexibility."

The company said it submitted a filing Tuesday with the North Carolina Utilities Commission seeking approval of the 950-MW gas-fired plant, which would replace about 397 MW of coal-fired generation at the H.F. Lee Plant in Wayne County. Progress said the project represents an investment of about $900 million.

The company expects the new plant to be in service in early 2013, ensuring compliance with the state's Clean Smokestacks Act, which establishes more stringent emission-reduction targets in 2013. In addition to an estimated 60% cut in the facility's CO_2 emission rate, the new units will decrease the facility's emission rates for mercury by 100%, sulfur-dioxide by nearly 100% and nitrogen oxides by more than 95%, the utility said.

"This is an important milestone for our company and for our state," said Lloyd Yates, president and CEO of Progress Energy Carolinas. "The Lee Plant has been producing electricity reliably and cost-effectively for our customers for more than 50 years, but as emission targets continue to change, and as legislation to reduce carbon emissions appears likely, we believe in this case, it's in the best interest of our customers to invest in advanced-design, cleaner-burning generation for the future."

Yates added that Progress is not giving up on coal, saying the fuel will "continue to be vital to our ability to meet customer needs reliably and affordably in future years. We have already invested more than $1.3 billion in clean-air equipment at our largest units, and we have reduced emissions dramatically. Our objective is to maintain the right balance of resources — nuclear, natural gas, coal, hydroelectric, solar, biomass and energy efficiency — to make our company and state more energy independent and to minimize the risk of customer price spikes due to volatility in cost or supply of any single fuel source."

The utility said the project also will require construction of a gas pipeline to fuel the new units and provide the additional benefit of extending large-volume gas supply more deeply into eastern North Carolina. The pipeline plan has not been completed. — *Jeff Barber*

Marketer rankings notice

Gas Daily is currently compiling data for a second-quarter 2009 ranking of North American gas marketers by daily physical wholesale volumes sold. *Gas Daily* staff intends to compile the rankings from information appearing in reports filed with the Securities and Exchange Commission.

For companies that are not publicly traded or do not provide such data to the SEC, staff requests quarterly gas sales data be reported in writing, and verified by executive personnel, no later than Monday, August 31. Please contact Stephanie Seay by phone at 865-690-4319, fax 865-690-0933, e-mail stephanie_seay@platts.com; or Mark Davidson at 202-383-2148, mark_davidson@platts.com, with any questions.

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NPS, the Interior Department and other state and federal agencies.

"It is our intent to review existing shoreline conditions and available alternatives in partnership with interested state and federal agencies at some time in the future, and we acknowledge and appreciate that Weaver's Cove has encouraged this and has offered to facilitate this process," Fosburgh wrote. "To date, however, this has not occurred, and no conclusions have been reached."

Timothy Timmermann, an environmental scientist with EPA Region One's Office of Environmental Review, said in a separate FERC filing that "we appreciate that Weaver's Cove acknowledged agency concerns with respect to how certain elements of the mitigation plan and the process to date were characterized."

At the same time, Timmermann stressed that "we have not approved the [updated mitigation] plan and we do not wish our review of the plan to be viewed as an indication that we have made any decision on whether a license should be approved for the project at this time."

Timmermann, with agreement from Fosburgh, called for a meeting with FERC staff and appropriate state and federal agencies "to discuss the status of our meetings with Weaver's Cove and to analyze whether the scope of analysis for the EIS continues to be appropriate based on our understanding of the project to date."

The most recent version of the Weaver's Cove project, which has been revamped since its original FERC approval in 2005, received tentative approval of its waterway plan from the US Coast Guard last month, but state and local officials are demanding more detailed information about the revised plan (*GD 8/4*). — *Melanie Tatum*

Interest in lease sale lukewarm ... *from page 1*

economic conditions that have caused exploration-and-production companies to rein in activity and a gas glut that has sent prices to seven-year lows.

"The price of natural gas ... is not helping interest" in the relatively large number of recycled or newly available blocks in the sale, Herbst said.

However, "I was anticipating worse than this," he said, referring to the number of bids submitted to the agency by the 10 am CDT Tuesday deadline. "Maybe I'm a pessimist, but this is a little bit better."

Recycled leases, which have five- to 10-year terms, are usually a bright spot in lease sales as oil companies vie for a fresh look at the newly relinquished leases. This year's auction features 336 such leases.

While the number of recycled leases in shallow waters of 200 meters and below was relatively large at 210 blocks, those blocks failed to pull in many bids, MMS records show. Just 34 tracts received bids, while another eight bidders went for blocks in 400 to 800 meters of water.

Mid-depth leases appear to be more popular as waters of 800 to 1,600 feet lured the largest number of bids, 94, for any single category. And while deepwater tracts have been the biggest magnet in Gulf lease sales for several years, blocks in water depths of 1,600 to 2,000 meters received just 10 bids in today's auction, MMS said. — *Starr Spencer*

Anadarko drilling through downturn ... *from page 1*

ing our drilling programs to make sure that prices don't drop below our cost of capital," said Hackett, whose company produces more than 2 Bcf/d in the US. "We'll continue to watch where prices go in the near term, but that's a very tactical move. The consumer will not feel the amount of gas that we shut in at all," he said.

"As soon as prices recover a little bit, which they're showing in forward mar-

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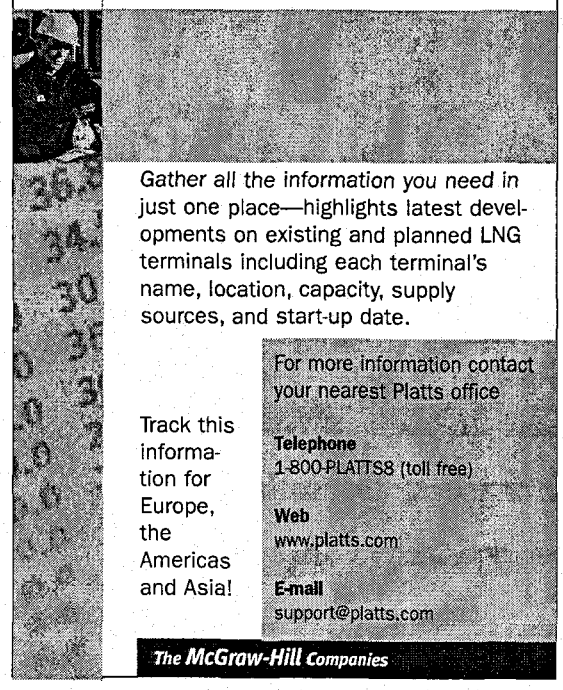

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kets they will in 2010 once the economy reverses, gas from drilling will keep this price between $5 and $7. That's equivalent to about $42/barrel of oil," Hackett said.

He pointed to an industry-wide expansion in shale gas plays as the basis of long-term pricing stability. "Rig rates are coming back again even at these very low prices because we've found these incredibly economic shale resources that we're going to continue to attack as an industry."

Increased imports of liquefied natural gas also will help keep a cap on gas price volatility, Hackett predicted. "The LNG distribution capacity in this country has increased four-fold. It's now at 12 Bcf/d-plus, and it's actually doubling to 25 Bcf/d," he said.

"LNG will become the peaking fuel and it will end up being put in storage, so it will actually keep the price caps down to a lower level by moving from international markets to our markets," Hackett said. "The storage will stay full and it'll end up keeping prices from going too high."

The CEO also said that because much of the increase in domestic gas production will be coming from onshore shale gas plays, overall supply will be less susceptible to disruptions from hurricanes in the Gulf of Mexico.

Hackett said he was attending the rally, sponsored by Energy Citizens, to support his employees who were lobbying for changes to the Waxman-Markey climate change bill.

Anadarko bused in about 300 employees from its headquarters in The Woodlands, Texas, about 25 miles north of Houston. In all, about 3,500 people, many of them energy company employees transported in from remote locations, attended the lunchtime rally in a downtown theater.

Hackett said he was "terribly disappointed" in the House of Representatives-passed version of the climate bill, which establishes a cap-and-trade system to reduce carbon emissions. The bill is expected to be taken up by the Senate when

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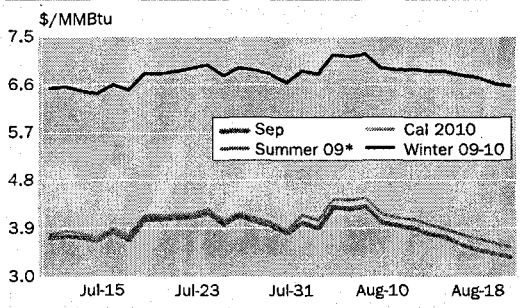
Platts-ICE Forward Curve — Natural Gas, Aug 18 (¢/MMBtu)

Prompt month:Sep 09

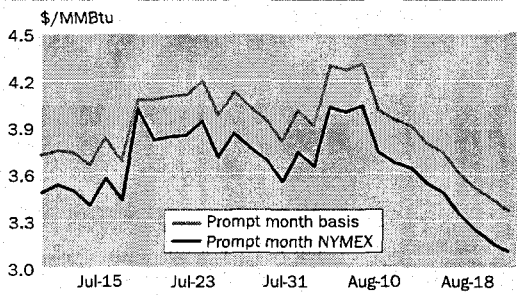
Algonquin, city-gates	26.00
Transco, zone 6-NY	30.00
Texas Eastern, M-3	25.50
Columbia Gas, Appalachia	4.75
Transco, zone 3	-2.00
Transco, zone 4	-2.50
Florida Gas, zone 3	4.25
Trunkline, LA	-7.00
Houston Ship Channel	-7.75
Chicago city-gates	-5.00
MichCon city-gate	1.75
Panhandle, TX-Okla.	-37.50
Waha	-23.00
El Paso, Permian Basin	-27.75
El Paso, San Juan Basin	-40.00
PG&E city-gate	8.75
SoCal Gas	-20.50
Northwest, Rockies	-48.25
Northwest, Sumas	-39.00
Dawn, Ontario	7.50
AECO, Alberta	-47.50

Summer season is April-October. Winter is November-March. *Balance of the season.

Algonquin, city-gates: Key packages, last 30 days



Algonquin, city-gates: Basis market vs NYMEX



Algonquin, city-gates: Forward curve

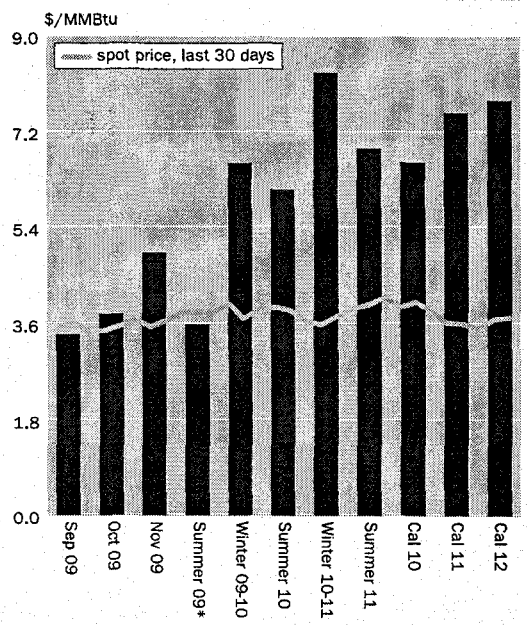


Table and graphs are created using Platts-ICE Forward Curve — Natural Gas (North America) data. Forward assessments as basis to the Henry Hub and full values are available for periods spanning three years. To see a sample and find information on how to subscribe to the full data set go to www.risk.platts.com. For more information on Platts services, please call +1-800-PLATTS8. For editorial questions call Sheetal Nasta +713-658-3203 or Samantha Santa Maria +713-658-3271.

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it returns from its August recess.

The House bill "doesn't address what is a realistic energy policy. It doesn't mention natural gas, which is the critical fuel for us to back up wind and solar," Hackett said.

"That is the genesis of a lot of our concerns about national security feeding petrodollars overseas, and it also tries to set up a virtual reality for us that somehow wind and solar can solve all our problems in the near term, which they can't." — *Jim Magill*

Ex-Amaranth trader takes the stand ... *from page 1*

Growing visibly more relaxed the longer he was on the witness stand, Hunter used his hands frequently to illustrate concepts such as "short" and "long," even "trading pit," under questioning by FERC's lead lawyer in the case, Todd Mullins.

In his first public statements since FERC began proceedings against him against him two years ago (*GD 7/26/07*), Hunter briefly reviewed his trading strategy before the collapse in the spread between summer 2006 prices and winter 2007 prices crushed Amaranth beneath billions of dollars worth of margin calls.

Summer 2006 prices were low and going lower, Hunter explained, because of large amounts of gas in storage due to high prices and damage to the Gulf Coast's infrastructure by hurricanes Katrina and Rita. Nonetheless, oil prices were on a tear and large utilities such as TXU were "selling contracts for huge amounts of natural gas," pointing to higher winter prices despite high storage levels, he said.

The prosecution at FERC headquarters in Washington marks the first time the commission has invoked authority it said it obtained from Congress in 2005 to take enforcement action against a futures trader because of the alleged effect his actions had on the physical price of gas.

ALJ Carmen Cintron will be asked to pick and choose from the competing testimonies of economists for either side, lawyers said in their opening arguments.

Mullins said FERC's chief witness will be Enron's former head of research, Vince Kaminski, "one of the few guys at Enron that stood up and spoke truth to power."

Mullins said Kaminski will show that Hunter manipulated contract expiration three months in a row by selling futures contracts at the last minute for ever lower prices, dragging the eventual settlement price down.

Hunter's defense team lit into Kaminski in its opening arguments. "Dr. Kaminski has never traded a future in his life," attorney Matthew Menchel said.

Natural gas hub flow, Aug 18

Hub Name	Scheduled Flow	+/-	% Change	Daily Price	—31 Day Average— Flow	Price
ANR, La.	582	-79	-11.98	3.135	650	3.411
Dracut, Mass.	7	7	2,000.61	-	52	3.696
Florida city-gates	2,180	-2,070	-48.70	3.910	2,271	4.371
Iroquois, receipts	964	90	10.28	3.525	848	3.718
Kern River, Opal plant	883	-10	-1.14	2.800	877	3.043
Niagara	807	183	29.24	3.425	551	3.640
Northern, Ventura	511	-50	-8.86	3.095	457	3.356
Northern, demarc	789	-63	-7.41	3.110	903	3.346
Northwest, Can. bdr. (Sumas)	792	-4	-0.49	2.870	808	3.086
PG&E, Malin	1,599	-53	-3.20	2.995	1,651	3.267
Stanfield, Ore.	6	6	1,439.23	2.870	2	3.157
Transco, zone 3	1,493	58	4.07	3.150	1,715	3.450
Transco, zone 6 N.Y.	1,569	24	1.54	3.760	1,397	3.773

Volumes in 000 MMBtu; prices in $/MMBtu. For more information, contact Bill Murphy at 720-548-5485.

Source: Platts data

NYMEX Henry Hub gas futures contract, Aug 18

	Settlement	High	Low	+/-	Volume
Sep 2009	3.096	3.239	3.088	-6.7	83639
Oct 2009	3.464	3.619	3.455	-9.1	53607
Nov 2009	4.326	4.461	4.319	-8.6	15137
Dec 2009	5.106	5.234	5.096	-8.4	6689
Jan 2010	5.395	5.516	5.385	-8.2	5074
Feb 2010	5.441	5.507	5.431	-8.1	1096
Mar 2010	5.411	5.510	5.406	-8.0	2412
Apr 2010	5.368	5.431	5.358	-7.8	2159
May 2010	5.433	5.476	5.430	-7.7	513
Jun 2010	5.533	5.570	5.532	-7.5	296
Jun 2010	5.655	5.710	5.655	-7.6	265
Aug 2010	5.751	5.787	5.742	-7.5	221
Sep 2010	5.818	5.850	5.816	-7.3	42
Oct 2010	5.938	6.006	5.938	-7.3	433
Nov 2010	6.333	6.360	6.323	-7.3	53
Dec 2010	6.708	6.765	6.708	-7.3	33
Jan 2011	6.938	7.005	6.938	-6.8	238
Feb 2011	6.936	6.956	6.935	-6.5	62
Mar 2011	6.763	6.792	6.759	-6.3	68
Apr 2011	6.298	6.310	6.298	-4.8	68
May 2011	6.268	6.280	6.268	-4.8	10
Jun 2011	6.348	6.370	6.348	-4.8	10
Jul 2011	6.438	6.460	6.438	-4.8	42
Aug 2011	6.508	6.512	6.508	-4.8	42
Sep 2011	6.538	6.580	6.538	-4.8	51
Oct 2011	6.618	6.623	6.618	-4.8	177
Nov 2011	6.863	6.863	6.863	-4.8	0
Dec 2011	7.148	7.148	7.148	-4.8	0
Jan 2012	7.358	7.358	7.358	-4.8	3
Feb 2012	7.353	7.360	7.360	-4.8	1
Mar 2012	7.133	7.135	7.133	-4.3	15
Apr 2012	6.448	6.448	6.448	-3.3	19
May 2012	6.398	6.398	6.390	-3.8	1
Jun 2012	6.478	6.478	6.478	-3.8	28
Jul 2012	6.568	7.360	7.360	-3.8	35
Aug 2012	6.633	6.633	6.633	-3.8	57

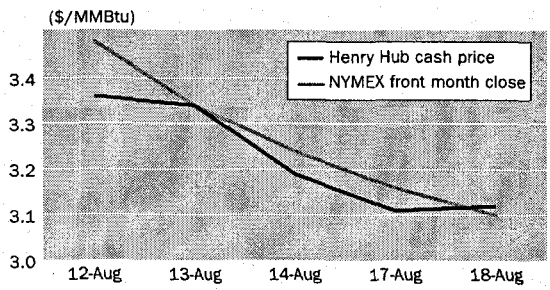
Contract data for Monday

Volume of contracts traded: 251,751

Front-months open interest:

SEP, 95,043 ; OCT, 156,244; NOV, 78.535

Henry Hub/NYMEX spread



Platts oil prices, Aug 18

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid[1]	69.70-69.85	11.10
3% Resid[1]	67.85-68.00	10.80
Crude spot		
WTI (Sep)[2]	69.09-69.11	11.86
New York spot		
No.2[1]	77.38-77.59	13.30
0.3% Resid LP[3]	69.85-69.95	11.12
0.3% Resid HP[3]	67.95-68.05	10.82
0.7% Resid[3]	67.50-67.60	10.74
1% Resid[3]	67.35-67.45	10.72

1= barge delivery; 2= pipeline delivery; 3= cargo delivery

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"He doesn't know what's going on."

Menchel said FERC decided on a story early in its investigation and now is "forcing the data and the facts to fit."

Mullins urged the judge to rely on her common sense: "Amaranth's selling, the price is falling. Do you believe that what happened in the last 30 minutes was the result of supply and demand in the US gas market?"

Mullins quoted from instant messages between Hunter and others that talked about "smashing the close." Menchel said Hunter was happy to have those instant messages in evidence to show in a broader context his innocence. FERC is "cherry picking" the evidence, Menchel said.

As far as common sense, "if this stuff were simple, anybody could be a hedge fund natural gas trader and make profits," Menchel concluded. "Everybody can't."

Hunter's trading strategies were complex and revolved around spread trades between two differing time periods, making an individual month's closing price less relevant, he argued.

While Amaranth and Hunter's former colleague, Matthew Donohue, settled accusations of market manipulation last week for $7.5 million (*GD 8/16*), Hunter has challenged FERC in federal court, saying the Commodity Futures Trading Commission has exclusive jurisdiction over futures trading. The CFTC, in a letter to the court hearing Hunter's appeal, agrees. Arguments in that appeal are scheduled for September 23 in the US Circuit Court of Appeals for the District of Columbia.

Hunter's motion for Judge Cintron to recuse herself for using two economists from a separate office from FERC as her advisors was dismissed by Cintron, along with five other defense motions, immediately after the hearing got under way Tuesday morning.

Hunter is expected to return to the witness chair today. — *Bill Holland*

Transco, FGT file for approval of LNG-linked Pascagoula line

Nearly two years after the open season for the project closed, Transcontinental Gas Pipe Line and Florida Gas Transmission last week filed for Federal Energy Regulatory Commission approval of their Pascagoula Expansion Project to bring liquefied natural gas to market.

The $59 million project would stretch from the Gulf LNG Clean Energy terminal near the Port of Pascagoula, Mississippi, to Transco's Mobile Bay Lateral. Both the terminal and pipeline are projected to be in service in the fall of 2011.

Angola LNG, the sole supplier to the LNG terminal, signed precedent agreements for the project's full capacity of 810,000 Dt/d following an open season held in 2007 *(GD 11/6/07)*.

The expansion would involve construction of a 26-inch-diameter pipeline extending 15.5 miles from the Gulf LNG Pipeline in Jackson County, Mississippi, to interconnections with Transco's Mobile Bay Lateral in Mobile County, Alabama, and with FGT's Grand Bay meter station proposed as part of its Mobile Bay Lateral expansion project.

Transco will have a 57.7% ownership in the line and FGT will hold 42.3%, according to the FERC filing.

The Gulf LNG Clean Energy terminal, currently under construction, will have a peak sendout of 1.5 Bcf/d, and includes two 160,000-cubic-meter storage tanks *(GD 10/21/04)*. It is 50%-owned and will be operated by El Paso, with Houston-based investment firm Crest Group holding 30% and Angola's state-owned Sonangol holding 20%. — *Stephanie Seay*

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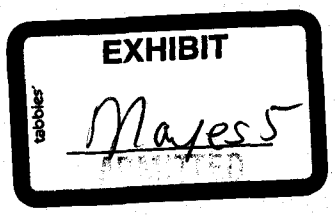

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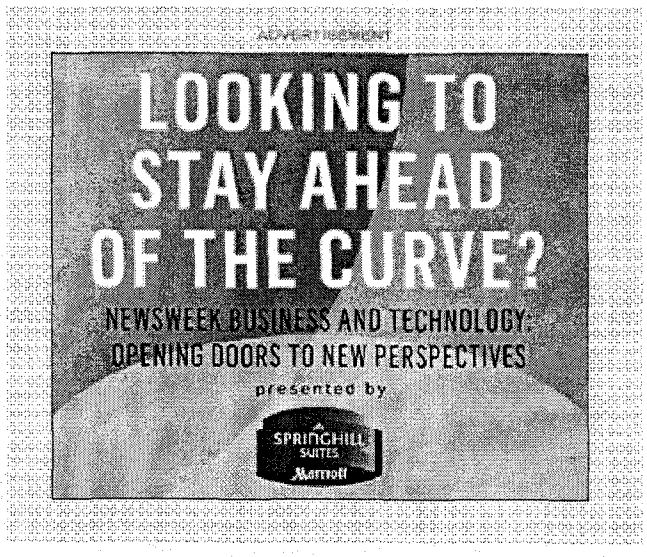
Taking a Dim View of Solar Energy

Who could possibly be against homeowners using solar panels to power their homes? Utility companies.

By Matthew Philips | Newsweek Web Exclusive
Aug 25, 2009

Not long ago, most homeowners saw their roofs as simply something to keep the rain out. Now they see them as a source of electricity. Despite the bad economy, or maybe because of it, the rooftop-solar industry is booming, as Americans become increasingly intrigued by the idea of turning their roofs into mini power plants and cutting their electric bills. In 2008, 33,500 rooftop solar systems were installed in the United States, a 63 percent increase over the amount of capacity installed in 2007. In California, the solar capital of country, the increase was 95 percent.

Meanwhile, the outlook for the other side of the solar industry—the large, centralized power plants—isn't so sunny. These megaprojects—think acres of desert landscape covered in thousands of solar panels sending electricity through transmission lines—controlled mostly by utility companies that have had a monopoly over the country's electricity grid since the turn of the last century, were supposed to be the key to the future of the solar industry. So far, they're getting vastly outpaced by the decentralized rooftop approach. According to the Interstate Renewable Energy Council's 2006-08 count, consumers added 522 megawatts to the grid; whereas utility generated sites added just 96 megawatts.



The disparity has utilities worried about loosing their grip on the country's energy industry, and the $130 billion residential electricity market. In some cases, utilities are actually taking direct steps to thwart rooftop solar. Two weeks ago in Colorado, the state's biggest utility, Xcel, tried passing a surcharge on homes and businesses using rooftop solar power. The public went ballistic, and with pressure from Democratic Gov. Bill Ritter, the proposal was eventually shelved. In early July, New Mexico's biggest utility, PNM, filed an official request to dramatically reduce incentives for businesses and homeowners to install solar panels, and is now fighting with state lawmakers over whether it has the right to exclusively own solar panels systems hooked up to its grid. During California's last legislative session, Southern California Edison, which serves 13 million residents, successfully lobbied against a bill that would have allowed the city of Palm Desert to pay solar users for the excess power they generate.

"There is across the board tension between distributed solar generation and utilities," says Adam Browning, executive director of The Vote Solar Initiative, a solar advocacy group in San Francisco. "They've had the

energy pie to themselves for a century, and now facing a future where clean distributed energy will play a large part, they're looking for ways to profit from it and maintain control." Can we really blame them though? That's just capitalism right? "Part of having a monopoly is serving the public trust," says Browning. "People want solar panels on their roofs, so utilities should be working to make that happen rather than getting in the way."

It's not hard to understand why a big utility might not like the idea of homes, businesses, schools, and even government buildings being covered in solar panels. If every building in America is generating its own solar energy, that throws a big wrench into their business model. It's why utilities have historically been opposed to solar power, say solar's advocates. But as most states have passed renewable-energy standards recently, mandating that a certain percentage of their energy come from renewable sources, utilities have become reluctant players in the solar game because, frankly, they have no choice. Rather than get on board with rooftop solar, though, utilities decided to do what they do best: build a centralized system of large power plants, and make money by charging customers for taking power off the grid. While large-scale utility projects do hold the promise of generating massive amounts of electricity, so far they've delivered precious few new sources of electricity, as dozens of proposed projects are languishing in the application process. Building the thousands of miles of new transmission lines these projects require not only costs millions, it's fraught with red tape: zoning and permitting regulations, and issues like eminent domain, as lines are strung across both public and private property.

The Energy Policy Act of 2005 called for the addition of 10,000 megawatts of renewable energy on public lands by 2015, much of which was thought to be provided by big solar plants. But four years in, things are barely off the ground. The two biggest solar projects in the U.S., which are both in the Nevada desert and came online in 2007, combine to produce just 78 megawatts, 14 of which are used solely to power Nellis Air Force Base. Interior Secretary Ken Salazar says that by 2010, 13 utility projects will be under construction on public land in the Southwest, but that's still years away from generating electricity. California has the country's most aggressive renewable goal, mandating that 20 percent of its energy come from renewable sources by the end of 2010. Lawmakers are now pushing that to 33 percent by 2020. But at its current pace, it won't come close to being met. None of Southern California's four biggest utilities, Southern California Edison, San Diego Gas and Electric, Pacific Gas and Electric, and the Los Angeles Department of Water and Power, are on target largely, critics say, because they're too focused on trying to make money off big centralized plants.

"The utilities are more interested in protecting their stranglehold on the power grid and preserving their century-old business model than they are producing clean electricity," says Jim Harvey, who heads up the Joshua Tree, Calif.-based Alliance for Responsible Energy Policy, an advocacy group that's staunchly opposed to utility-generated solar power. Harvey actually believes that the country's entire renewable portfolio can be achieved through rooftop solar alone. That may be possible from a sheer megawatts perspective, but from a practical standpoint, it's way over-ambitious. With no centralized source, how do you run traffic or street lights? What if it rains for a week? We still don't have foolproof means to store solar power, so for now, distributed generation needs the grid as a backup.

This isn't to take anything away from the private-sector solar boom. In 2008, rooftop solar added more than 10 times the amount of power to the country's grid than utilities did. Maryland-based Sun Edison, the country's biggest installer of solar panels in the retail market, added more electricity to the grid last year, 25 megawatts, than did the entire utility industry. San Francisco-based SunRun has come up with a way to let

homeowners make a down payment, usually about $1,500, on what is typically a $30,000 solar-panel system, lock in a below-market fixed rate for their electricity, then use the savings to help pay off the cost of the system.

This is all possible thanks to state and federal government subsidies, and the declining cost of producing electricity from solar panels, down to $6 per watt from about $9 per watt in 2006. "We're buying panels at prices I didn't think we'd see for at least another decade," says John Berger, founder of Standard Renewable Energy, a Texas-based company that provides homeowners and businesses ways to reduce their energy costs, including on-site solar generation. Berger expects to have revenues of $50 million in 2009, this after doing $11 million in business last year, and only $1.5 million in 2007. He gets particularly agitated when talking about the utilities. "When solar came along, they thought they could ignore it. Then they thought they could just monopolize it. But the private sector is giving them competition, and now they're scared."

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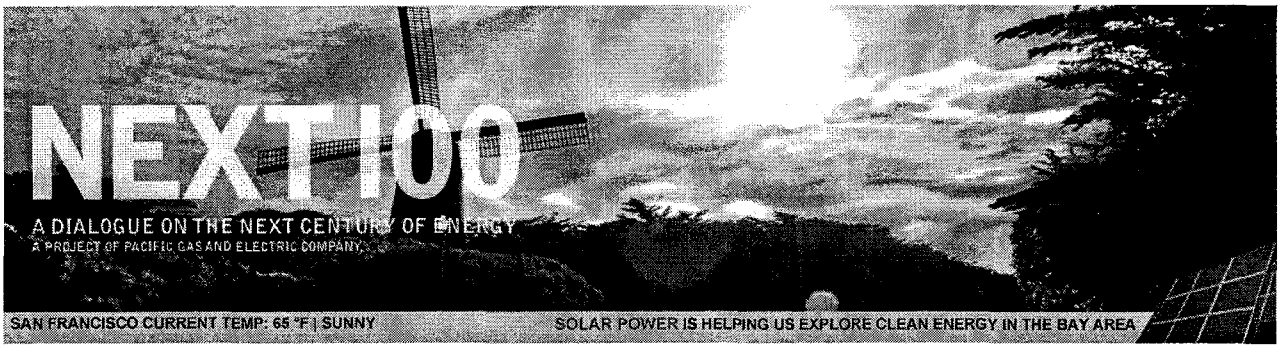

ABOUT THE BLOG

Supported by Pacific Gas and Electric Company, NEXT100 provides an in-depth look at the intersection of the clean energy business and the environment. Drawing on the collective experience of PG&E and insights from its readers, the blog is designed to encourage an open dialogue on the trends that will most impact the energy industry and our customers over the next 100 years--PG&E's second century in operation.

NEXT100 is co-written and edited by Jonathan Marshall, Leonard Anderson, Jennifer Zerwer and Katie Romans. Postings on NEXT100 represent the opinions of the authors and do not necessarily reflect the official position of Pacific Gas and Electric Company (PG&E).

In addition to writing about what PG&E is doing, we also blog about emerging trends in the business of clean energy, new technologies, the environment, climate change, policy, and the opportunities and challenges of building a clean energy future.

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- PG&E currently holds contracts for renewable energy deliveries that represent over 20 percent of its future energy needs.
- About 50 percent of all electricity delivered by PG&E comes from resources that emit no greenhouse gases - hydroelectricity, nuclear power, and renewable power from biomass, geothermal, wind, biogas, and solar energies
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San Francisco-based PG&E is one of the oldest - and largest - utilities in California. The company was incorporated in 1905 but traces its early roots to the Gold Rush days when small hydroelectric companies dotted the foothills of the Sierra Nevada. Today, PG&E's service area covers 70,000 square miles in northern and central California, from the far northern reaches near the Oregon border south to Bakersfield. The company provides energy services to 15 million people, or about 1 of every 20 Americans.

You can find more information about PG&E at www.pge.com.

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A few notes:

- Comments for NEXT100 are moderated and must be approved before posting. Comment approval will typically occur within 24 hours.
- Personal attacks and foul language will not be tolerated.
- Please stay on-topic. Off-topic comments will not be approved.
- Comments should contribute to the dialogue.

Thank you for taking the time to read this comment policy. We encourage your participation and look forward to an active exchange of ideas.

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Table 5-1
Avoided Total Capital & Fixed Operating Costs

	2010	2015	2025
Low Penetration Case			
Dependable Solar DE Capacity (MW at Generation Level)	3	16	25
Total Solar DE Energy (GWh at Generation Level)	17	106	176
Cumulative Avoided Capital Investments (2008 $000)	0	0	0
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	659	3,728
Total Avoided Annual Energy Cost (2008 $000)	936	5,606	8,547
Medium Penetration Case			
Dependable Solar DE Capacity (MW at Generation Level)	3	32	265
Total Solar DE Energy (GWh at Generation Level)	18	181	1,789
Cumulative Avoided Capital Investments (2008 $000)	0	0	184,581
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	1,351	18,946
Total Avoided Annual Energy Cost (2008 $000)	980	10,100	96,596
High Penetration Case			
Dependable Solar DE Capacity (MW at Generation Level)	3	32	348
Total Solar DE Energy (GWh at Generation Level)	18	181	3,863
Cumulative Avoided Capital Investments (2008 $000)	0	0	299,002
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	1,351	20,965
Total Avoided Annual Energy Cost (2008 $000)	980	10,100	182,009
Single-Axis Sensitivity			
Dependable Solar DE Capacity (MW at Generation Level)	4	36	351
Total Solar DE Energy (GWh at Generation Level)	19	188	4,046
Cumulative Avoided Capital Investments (2008 $000)	0	0	299,002
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	1,546	21,444
Total Avoided Annual Energy Cost (2008 $000)	1,031	10,578	188,846

5.2 Solar DE Capacity Value

5.2.1 Solar DE Dependable Capacity

As previously discussed in Sections 3 and 4 of this Report, output from the solar DE resources is only partially coincident with the peak demand of the APS load (see Figure 5-1). As such, the amount of capacity that can be relied upon from the solar DE resources is less than the total installed capacity of the solar DE resources.

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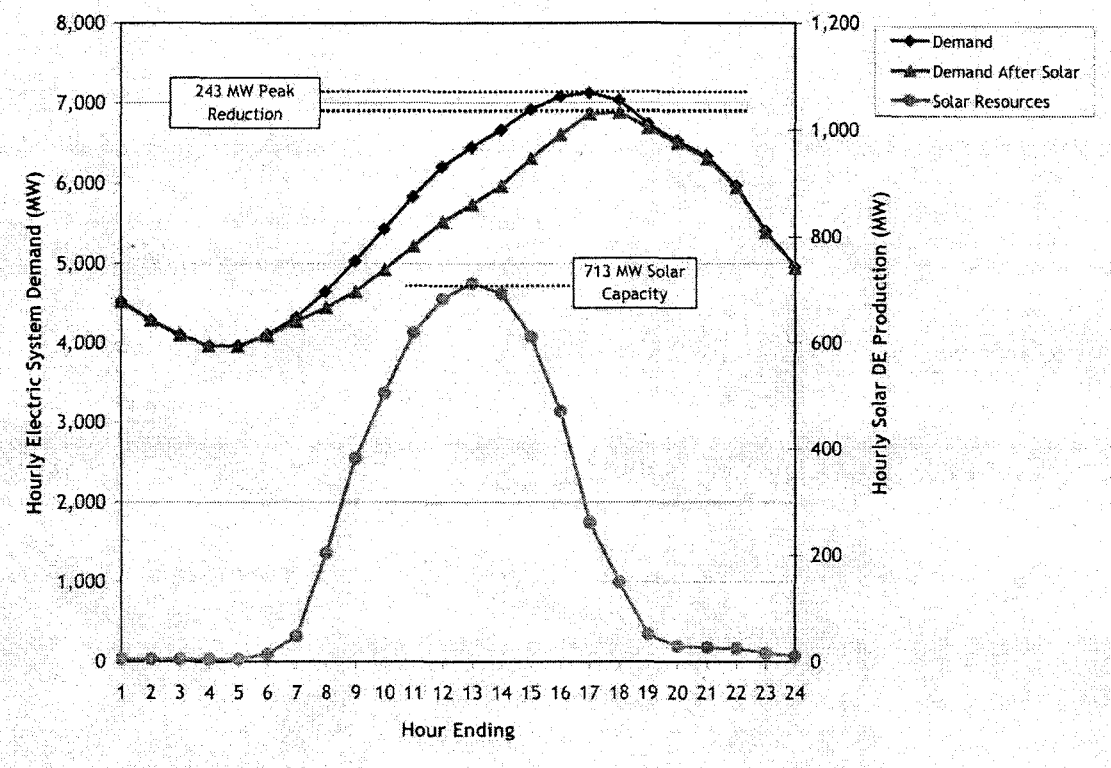
Figure 5-1: Coincidence of Solar DE Output with the APS System Load Shape, Solar DE at 10% of Peak



Transmission and distribution planning is usually concerned with the peak demand placed on the electric facilities; therefore, an analysis of the coincidence of the solar DE capability at the time of the peak on the electric facilities is sufficient to determine the impact of solar DE capacity. However, power supply planning is concerned with the ability of a given resource portfolio to reliably serve the total system load – not just at the time of the peak but across all hours of the year. The capability of solar DE resources to displace power supply resources must, therefore, be determined through a different analysis than that used for the transmission and distribution analyses.

Determining Power Supply Capacity Reliability

Power supply planning is typically performed such that resources are added to meet a given level of capacity reserves above the forecast peak demand, or reserve margin. In the case of APS, the planning reserve margin is 15 percent. While a planning reserve margin reflects a reasonable rule-of-thumb for long-term planning purposes, the 15 percent reserve margin is actually derived through a more rigorous analysis of the quantity of resources needed to maintain a minimum level of reliability to serve customer loads. The electric industry has adopted several similar methods to compute such reliability metrics; generally they are all related to a specific measure of how likely a utility will be able to serve the loads of its customers.

Common measurements for power supply reliability targeted by electric utilities include *one hour in 10,000 hours* and *one day in 10 years*, which can be interpreted as follows: the electric utility will be able to serve all customer loads but for one hour in 10,000 hours (there are 8,760 hours in a year), or will be able to serve all daily peaks but for one day in 10 years, respectively. These metrics reflect the very high levels of reliability demanded by utility customers and the regulatory bodies that govern electric utilities.

Common analytic approaches and reliability measurements include loss of load expectation (LOLE), loss of load probability (LOLP), and loss of load hours (LOLH), with approaches varying for the specific time interval and dependent variable being measured. A utility will typically evaluate the ability of its power supply portfolio to meet a desired target based upon these metrics, and will develop a plan for resource additions that will ensure that they achieve their target. The quantity of capacity that meets a given target is usually stated in terms of the more commonly discussed reserve margin, which experience indicates will usually be in the range of 12 to 18 percent for the equivalent reliability criteria.

Besides a general 15 percent reserve margin used for long-term planning, APS uses an LOLE approach when evaluating the reliability of a given portfolio. The LOLE approach measures the likelihood (expectation) that customer loads will or will not be served by a given portfolio. For the purposes of this Study, APS, the stakeholders, and the Study team determined that an LOLE approach applied to the solar DE resources would provide a highly defensible approach for measuring the "dependable capacity" available from the solar DE resources.

Solar DE Dependable Capacity

To evaluate the dependable capacity of solar DE resources, APS performed a series of LOLE simulations of its existing portfolio after adding 100 MW of the solar DE technologies being investigated for this Study, as described in Section 2 of this Report. Because the LOLE measurement can vary significantly depending on the underlying load shape, the LOLE computations were performed for five recent historical annual hourly load profiles: 2003 through 2007. Additionally, the LOLE was computed for forecast load conditions over the next five years by simulating load growth on each of the historical load profiles.

The average LOLE over the forecast period was computed and recorded for the simulated resource portfolios including 100 MW of the various solar DE resources. These values were then compared to the LOLE computed from an evaluation of the APS resource portfolio without the solar DE resources. In the analysis, combustion turbine resources were added to the resource portfolios without solar DE until the average LOLE recorded for the *traditional portfolio* equaled the LOLE for the *solar DE portfolio*. With an equivalent LOLE, the two portfolios provide the same level of reliability, or dependability, for serving the APS system loads.

For a given pair of *traditional* and *solar DE portfolios*, the ratio of the combustion turbine capacity to the solar DE capacity represents the relative quantity of traditional capacity needed to provide the same level of reliability as the solar DE resource or, conversely, the percent dependable capacity provided by the evaluated solar DE resource. Table 5-2 provides the percent dependable capacity (for power supply planning) computed for each of the solar technologies that make up the solar DE cases evaluated by this Study.

Table 5-2
Percent Dependable Solar DE Capacity
100 MW Installation

Solar DE Technology	Base Case Resource Plan 2007	2006	2005	2004	2003	Average
Solar Hot Water	47.8%	41.8%	43.9%	46.3%	43.1%	44.6%
Daylighting:						
Low Penetration Case	72.7%	64.1%	N/A	58.7%	62.0%	64.4%
High Penetration Case	73.3%	66.2%	N/A	59.0%	63.6%	65.5%
Residential PV:						
18.4° Tilt, S-Facing	41.5%	52.5%	48.4%	41.1%	42.3%	45.2%
18.4° Tilt, SE-Facing	28.4%	40.8%	36.5%	28.7%	32.5%	33.4%
18.4° Tilt, SW-Facing	54.2%	63.4%	58.8%	53.1%	50.7%	56.0%
Commercial PV:						
10° Tilt, S-Facing	43.7%	55.2%	50.8%	42.9%	44.3%	47.4%
0° Tilt, N/S Single-Axis Tracking	73.1%	75.3%	74.0%	68.3%	60.4%	70.2%

Diminishing Dependable Capacity

In addition to the analysis of dependable capacity for a small quantity (100 MW) of solar DE, an analysis was performed to determine the amount of dependable solar DE capacity that might diminish as installation of solar DE resources increased on the APS system. As discussed in Section 4, as more solar DE resources are added to the electric system, the APS system peak demand will be pushed to a later hour in the day (e.g., the summer peak demand will move from the traditional hour ending at 5:00 PM to 6:00 PM, or even 7:00 PM). Because the output of the solar DE resources becomes significantly less as the available sunlight diminishes at dusk, the delay of the peak hour to a later hour could significantly diminish the ability of the solar DE resources to meet the electric system peak demand and satisfy reliability planning criteria.

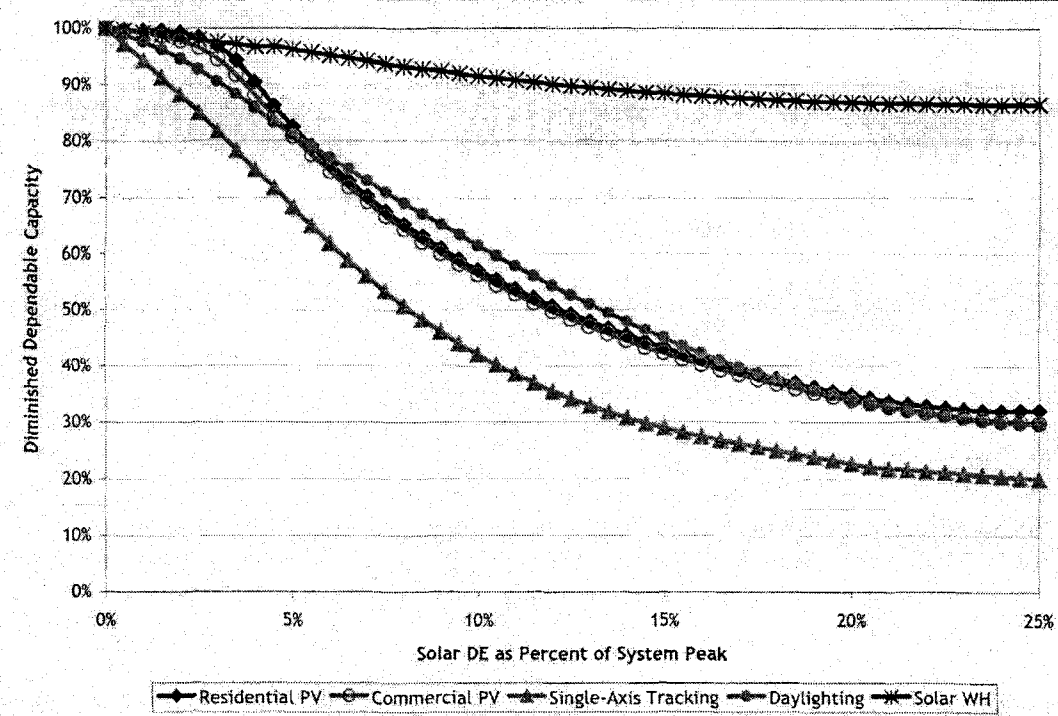
To analyze this effect, the LOLE analysis was repeated but this time using incrementally increasing quantities of solar DE resources. This LOLE analysis was performed by APS for each technology comprising the solar DE cases. Computational requirements limited the analysis to a single historical year, 2006, for daylighting, and 2005 for the other solar DE technologies.

As depicted in Figure 5-2, as installed solar DE resources became large relative to the peak demand of the APS system, the dependable capacity of the solar DE resources declined. The commercial single-axis tracking PV technology (simulated for the single-axis sensitivity) is most notably affected by the impact of diminishing capacity dependability with increasing implementation. Solar hot water technology is the least affected. These effects can be understood by considering the typical daily profiles for the solar DE technologies.

Since solar hot water incorporates natural storage characteristics, the dependable capacity of the solar hot water technology is not affected significantly by the coincidence of available sunlight with the electric system peak. The electric load avoided by a solar hot water system is minimal, since a traditional electric water heater operates throughout a 24-hour period, and commonly after sunset.

At the other end of the spectrum are solar PV technologies that track the sun. At low implementation rates, these solar resources provide relatively high dependable capacity due to the higher output that these resources provide across a greater number of hours, and a higher coincidence with the system peak load hour. However, this "longer duration" and more coincident output profile tends to push the electric system peak to a later hour more readily than the other evaluated solar DE technologies. This attribute, coupled with the steep drop-off of the solar electrical output as the sun sets, causes the dependable capacity of single-axis tracking PV technology to diminish more rapidly than the other technologies as installations are added to the APS system.

Figure 5-2: Diminishing Value of Solar DE Capacity



Total Dependable Capacity by Solar DE Case

Projections of total dependable capacity for each solar DE involved several steps. First, the results of the solar DE dependable capacity analysis, including diminishing values with increased implementation, were applied to the general capacity characteristics for each solar DE technology and the different customer adoption rates described in Section 2. Coincidence of maximum capacity ratings for solar DE technologies and marginal peak demand loss factors, as described in Section 4, were also applied to the customer-level technology characteristics to determine the total dependable capacity for each solar DE case. The installed and dependable capacity for each case is depicted below in Table 5-3.

Table 5-3
Total Dependable Solar DE Capacity

	2010	2015	2025
Low Penetration Case			
Total Solar DE Capacity (Max MW at Meter)	4.0	32.7	52.7
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.0%	81.7%	80.5%
Incremental Demand Losses	21.8%	22.2%	22.5%
Weighted Dependable Capacity Factor	49.6%	47.6%	47.7%
Weighted Diminishing Value Adj. Factor	100.0%	100.0%	100.0%
Dependable Solar DE Capacity (Summer MW at Generation)	2.1	15.5	24.8
Medium Penetration Case			
Total Solar DE Capacity (Max MW at Meter)	4.0	63.3	730.7
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.0%	88.3%	97.7%
Incremental Demand Losses	21.8%	22.1%	22.2%
Weighted Dependable Capacity Factor	49.6%	46.8%	45.9%
Weighted Diminishing Value Adj. Factor	100.0%	99.6%	66.3%
Dependable Solar DE Capacity (Summer MW at Generation)	2.1	31.8	265.2
High Penetration Case			
Total Solar DE Capacity (Max MW at Meter)	4.0	63.3	1597.7
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.0%	88.3%	98.2%
Incremental Demand Losses	21.8%	22.1%	22.0%
Weighted Dependable Capacity Factor	49.6%	46.8%	45.6%
Weighted Diminishing Value Adj. Factor	100.0%	99.6%	39.9%
Dependable Solar DE Capacity (Summer MW at Generation)	2.1	31.8	348.2
Single-Axis Sensitivity			
Total Solar DE Capacity (Max MW at Meter)	4.3	66.4	1677.4
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.7%	88.7%	98.3%
Incremental Demand Losses	21.8%	22.1%	22.0%
Weighted Dependable Capacity Factor	55.6%	51.1%	50.1%
Weighted Diminishing Value Adj. Factor	100.0%	98.9%	34.9%
Dependable Solar DE Capacity (Summer MW at Generation)	2.5	36.4	351.3

An interesting result of the analysis of the dependable capacity under the single-axis sensitivity (which reflects assumptions consistent with the High Penetration Case except that single-axis tracking PV resources are assumed for all commercial PV installations) is that the total dependable capacity is virtually identical to that of the High Penetration Case by 2025. While intuition might suggest that single-axis tracking resources would provide higher levels of dependable capacity because of the greater coincidence with APS's system peak demand, the degree to which the dependable capacity diminishes for the single-axis technology at the high implementation levels almost completely offsets the higher dependable capacity that can be derived from smaller implementation levels.

5.2.2 APS Resource Expansion Plan & Projected Avoided Capacity

As previously mentioned, APS is in the process of finalizing its most recent resource expansion plan to meet the future needs of the APS electric customers. This plan is preliminary and subject to change, however, has been relied upon for the purposes of this Study. The plan reflects the best available data at this time concerning the future resources of APS.

APS maintains a mix of power supply resources, which total approximately 8,200 MW, to reliably meet the needs of its customers as of 2008. The generating resources in the existing APS portfolio include approximately:

- 1,150 MW of nuclear capacity,
- 1,750 MW of coal-fired capacity,
- 1,850 MW of natural gas-fired combined cycle capacity, and
- 1,500 MW of natural gas-fired peaking and steam generating resources.

Additionally, APS purchases approximately 1,900 MW of wholesale power from others, and currently purchases 55 MW of capacity from renewable resources.

By 2025, in its base case resource plan, without considering future installations of solar DE resources, APS would need to add the following resources to its existing portfolio to meet anticipated growth in load, as well as planned changes in existing resource capability:

- Approximately 800 MW of renewable generating resources (other than solar DE),
- Approximately 1,300 MW of intermediate and base-load generating resources,
- Approximately 3,300 MW of combustion turbine peaking resources,
- Purchase approximately 500 MW of wholesale power, and
- Reduce load through the implementation of approximately 600 MW of energy efficiency programs.

It is these future planned resources that APS can potentially avoid or delay through the implementation of solar DE resources in their system. However, certain of the future planned resources are immutable and cannot be delayed or avoided through the implementation of solar DE resources. These immutable resources include energy efficiency programs, planned renewable resources required to meet RES requirements, and planned base-load resources needed to enhance fuel and technology diversity in the APS portfolio. Future planned resources that can be potentially avoided or delayed through solar DE installations include combustion turbine peaking resources, intermediate combined cycle resource, and wholesale power purchases.

Existing and planned resources for the APS base case resource plan (without solar DE) and for each of the solar DE cases depicted for the Study are provided in Tables 5-4 through 5-7. Planned APS generating and purchase power resources have been reduced by the quantity of dependable solar DE described in Section 5.2.1.

For each solar DE case, the cumulative quantity of dependable solar DE capacity in each target year was compared to the planned APS generating resources. To the extent dependable solar DE capacity is projected to be sufficient to displace the installation of one or more planned generating resources, the APS resource plan was modified to avoid or delay the installation of

the generating resource(s). To the extent the projected dependable solar DE capacity was insufficient to displace a planned generating unit, wholesale purchases were reduced for the quantity of available dependable capacity.

In all cases, dependable solar DE capacity was projected to be insufficient to avoid the installation of the planned combined cycle resource. Therefore, the combined cycle resource planned by APS for installation in 2020 was not simulated in any case to be avoided through the installation of solar DE resources.

As depicted in Table 5-4, projected dependable solar DE capacity under the Low Penetration Case is insufficient to avoid or delay the installation of any of the planned APS generating resources. However, planned wholesale purchases equal to 15.5 MW in 2015, and which increase to 24.8 MW by 2025, can be avoided. As depicted in Table 5-5, dependable solar DE capacity is projected to be sufficient under the Medium Penetration Case to avoid two 94 MW combustion turbine resources by 2025, along with avoided wholesale purchases of 31.8 MW in 2015 and 101.5 MW in 2025.

For the High Penetration Case and the single-axis sensitivity, as depicted in Tables 5-6 and 5-7, respectively, dependable solar DE capacity is projected to be sufficient to avoid three 94 MW combustion turbine resources by 2025. Additionally, wholesale purchases of 31.8 MW in 2015 and 13.7 MW in 2025 can be avoided in the High Penetration Case. Similarly, avoided wholesale purchases of 36.4 MW in 2015 and 15.3 MW in 2025 are projected for the single-axis sensitivity.

Table 5-4
Comparison of APS Resource Plans: Base Case and Low Penetration Case

	Base Case Resource Plan			Low Penetration Case		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	3	16	25
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,290
Short-term Purchases	0	38	487	0	23	462
Total Resources	8,068	8,746	12,483	8,071	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,234	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	0
Planned Purchases				0	(16)	(25)

Table 5-5
Comparison of APS Resource Plans: Base Case and Medium Penetration Case

	Base Case Resource Plan			Medium Penetration Case		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	3	32	265
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,102
Short-term Purchases	0	38	487	0	7	410
Total Resources	8,068	8,746	12,483	8,072	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,234	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	(188)
Planned Purchases				0	(32)	(77)

Table 5-6
Comparison of APS Resource Plans: Base Case and High Penetration Case

	Base Case Resource Plan			High Penetration Case		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	3	32	348
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,008
Short-term Purchases	0	38	487	0	7	421
Total Resources	8,068	8,746	12,483	8,072	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,234	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	(282)
Planned Purchases				0	(32)	(66)

Table 5-7
Comparison of APS Resource Plans: Base Case and Single-Axis Sensitivity

	Base Case Resource Plan			Single-Axis Sensitivity		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	4	36	351
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,008
Short-term Purchases	0	38	487	0	2	418
Total Resources	8,068	8,746	12,483	8,072	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,235	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	(282)
Planned Purchases				0	(36)	(69)

5.2.3 Projected Avoided APS Capacity Costs

Based upon the avoided generating assets and wholesale purchase power capacity described in Section 5.2.2, it is possible to assign capital and fixed operating costs that APS would have incurred for these resources. Several fixed costs can be avoided, as follows:

- Capital costs associated with the avoided generating assets.
- Capital costs for transmission interconnection and system upgrades specifically assigned to the avoided generating assets.
- Fixed operating and maintenance costs of the avoided generating assets. These include annual maintenance costs, labor costs, rents and utilities, etc. that APS would incur for a generating unit whether the unit operates or not.
- Natural gas pipeline reservation fees. These are the fixed annual costs paid to the natural gas pipeline company to reserve a portion of the pipeline to serve the natural gas requirements of any avoided gas-fired generating asset.
- Avoided short-term market demand charges.

The assumptions APS is using in its base case resource plan for the fixed costs described above were reviewed and found to be reasonable and generally consistent with assumptions used by R. W. Beck and others in the industry for resource planning studies. As such, for the purposes of this Study, the capital cost and fixed O&M assumptions developed by APS for the General Electric LMS100 combustion turbine peaking resource modeled for installation in the APS resource plan were relied upon by the Study team. Additionally, the APS estimates for

transmission capital costs, natural gas reservation fees, and demand charges for short-term market purchases were utilized for the purposes of this Study. Table 5-8 depicts the capital cost assumptions in real 2008 dollars per installed kilowatt (kW). Table 5-9 depicts the capital cost spending curve applied to the composite combustion turbine and transmission capital costs, and Table 5-10 depicts the fixed operating costs assumptions in real 2008 dollars per kilowatt-year (kW-yr) used for the Study.

Table 5-8
Potential Avoided Capital Costs

	2008 $/kW
Avoided Combustion Turbine Capital Cost	$ 1,006.00
Avoided Transmission System Investment	$ 82.40

Table 5-9
Capital Spending Curve

	Percent Capital Expenditure Per Year
Two Years Prior to Commercial Operation	10%
One Year Prior to Commercial Operation	50%
Year of Commercial Operation	40%

Table 5-10
Potential Avoided Fixed Operating Costs

Costs in 2008 $/kW-yr	2010	2015	2025
CT Fixed O&M	7.28	7.28	7.28
Natural Gas Pipeline Reservation Fee	31.81	31.81	31.81
Short-Term Purchase Power Demand Charge	42.76	42.47	150.27

Using the fixed costs described above and the avoided resource capacity described in Section 5.2.2 yields the total avoided costs for each of the solar DE cases (see Table 5-11).

Table 5-11
Avoided Total Capital & Fixed Operating Costs

	Avoided Cost (2008 $000)		
	2010	2015	2025
Low Penetration Case			
Cumulative Avoided Capital Investments	0	0	0
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	659	3,728
Avoided Generating Unit Fixed O&M	0	0	0
Avoided Generating Unit Natural Gas Reservation	0	0	0
Total Avoided Annual Fixed O&M Costs	0	659	3,728
Medium Penetration Case			
Cumulative Avoided Capital Investments	0	0	184,581
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	1,351	11,598
Avoided Generating Unit Fixed O&M	0	0	1,369
Avoided Generating Unit Natural Gas Reservation	0	0	5,980
Total Avoided Annual Fixed O&M Costs	0	1,351	18,946
High Penetration Case			
Cumulative Avoided Capital Investments	0	0	299,002
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	1,351	9,943
Avoided Generating Unit Fixed O&M	0	0	2,053
Avoided Generating Unit Natural Gas Reservation	0	0	8,970
Total Avoided Annual Fixed O&M Costs	0	1,351	20,965
Single-Axis Sensitivity			
Cumulative Avoided Capital Investments	0	0	299,002
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	1,546	10,421
Avoided Generating Unit Fixed O&M	0	0	2,053
Avoided Generating Unit Natural Gas Reservation	0	0	8,970
Total Avoided Annual Fixed O&M Costs	0	1,546	21,444

5.3 Solar DE Energy Value

5.3.1 APS Costs of Dispatch

As previously mentioned, resources in the APS power supply portfolio are committed and dispatched in sufficient quantity to assure that all APS loads in each hour can be met in a reliable fashion at the lowest possible cost. Resources are generally dispatched in merit order so that low variable cost resources are utilized more often than high variable cost resources. As previously discussed, APS's existing portfolio is comprised of nuclear, coal-fired, natural gas-fired,

purchase power, and renewable energy resources. To this portfolio, APS plans to add additional renewable resources, natural gas-fired combined cycle and combustion turbine resources, a new base-load resource, and make short-term (seasonal) market purchases in quantities sufficient to meet targeted planning reserves.

APS has developed models to simulate the hourly commitment and dispatch of the existing and planned resources over a long-term planning horizon (beyond 2025). These models use an industry-accepted simulation model called PROMOD, licensed by Ventyx, a major vendor of electric utility simulation software in the United States. APS uses PROMOD to simulate the operation of its generating and purchase power resources and to project variable operating costs of potential future power supply plans.

To perform these simulations, APS models all major operating characteristics of each existing and planned resource, including maximum and minimum capacity ratings, heat rate curves, variable O&M costs, start-up costs, minimum operating constraints, and emission rates, to name a few. These operating characteristics are combined with projected fuel prices, emission prices, forecasted hourly loads, and spinning and operating reserve requirements to simulate the operation of the APS resource portfolio in future years. Through this process, APS can make reasonable projections about the variable operating costs of a given resource portfolio and compare these costs to alternative resource plans, as appropriate.

For the purposes of this Study, the Study team has relied upon the PROMOD models maintained by APS. Specific scenarios necessary to analyze the operation of the solar DE cases were developed by the Study team and were executed by APS using their PROMOD model. While the Study team has not reviewed and verified the detailed assumptions used by APS in its PROMOD model, it conducted several interviews with the APS resource planning staff to determine that the approach, processes, and assumptions used by APS are generally consistent with R. W. Beck, and by those used by the electric utility industry as a whole. The PROMOD models used for the solar DE Study are reported by APS to be the same models that APS has relied upon to develop its current power supply plan to be filed with the ACC, thus providing an additional level of assurance that the models should be reasonable for the purposes of this Study. The hourly variable cost results from the APS PROMOD simulations, as described below, were also reviewed and utilized for this Study, thus providing an opportunity to review detailed results from the APS models.

Because APS energy costs that can be avoided by solar DE installations will more often than not be generating resources fired by natural gas, one of the most critical inputs to the PROMOD model was the price assumed for future natural gas prices. For purposes of its power supply planning efforts, APS has developed a forecast for natural gas prices based on forward prices observed for the New York Mercantile Exchange (NYMEX) on July 31, 2008, with appropriate adjustments for delivery to the APS system. The delivered natural gas prices modeled by APS are referenced in Table 5-12, below.

Recent market trends have caused prices for natural gas to fall below the values being used by APS in their resource planning studies. For purposes of this Study, the natural gas price forecast was not modified, since these prices provide the best conformance to the current APS resource planning results. Additionally, the use of higher natural gas prices will have the effect of increasing the energy value of the solar DE resources, thus providing a somewhat optimistic assessment of solar DE.

One change that was made to the APS simulations was the modeling of future costs for emissions of green house gases (GHG). An assumption implicit in the forecasted solar DE adoption curves for the Low, Medium, and High Penetration Cases described in Section 2 was a relatively high increase in future retail rates. This rate increase was assumed to be caused in-part by the anticipated institution of future GHG legislation. For these solar DE cases, the Study team made ex-post adjustments to projected hourly and annual energy costs projected by APS to reflect the addition of future carbon dioxide (CO_2) emission allowance costs. For this adjustment, the Study team relied on it current market forecast of CO_2 prices assuming the institution of a national cap and trade program in 2012. The CO_2 prices assumed for these cases are depicted in Table 5-12.

Table 5-12
Projected Natural Gas & CO_2 Prices
Nominal $

	2010	2015	2025
Delivered Natural Gas Price ($/MMBtu)	9.14	8.44	9.61
CO_2 Allowance Price ($/ton)	-	20.94	52.30

5.3.2 Impact of Solar DE on Resource Commitment & Dispatch

Typically, when determining the energy value of utility programs that affect customer loads, such as solar DE resources, the load displaced by the operation of the solar DE resource is assumed to be the last increment of load being served by the utility (the marginal cost of electricity production). As APS loads are reduced by solar DE installations, APS will modify the commitment and dispatch of resources to meet the lower load levels. Any change in the total variable costs of generation and purchased power caused by serving lower loads is directly attributable to the solar DE installations. So long as total variable costs are reduced, the solar DE installations can be said to provide an energy cost savings to APS.

Because the energy produced by the solar DE resources predominantly occurs during the middle of the day, when electric system loads and costs of dispatch are typically high, solar DE installations have the potential to provide significant savings in energy costs. In general, when incremental reductions in load are small, significant savings in energy production costs are possible. However, when incremental reductions in load are large, significant changes in resource commitment may be required, which can diminish the value of the reduced load. Additionally, as reported in Section 5.2.2, the resource expansion plan assumed for the APS base case plan and for each of the solar DE cases are different. As such, resource commitment and dispatch will necessarily be different between the base and each of the solar DE cases, regardless of the quantity of load reduced.

Figure 5-3 depicts resource commitment and dispatch patterns projected for a typical summer day in 2025, with incremental load impacts simulated for the Low Penetration Case. Energy produced by solar DE resources under the Low Penetration Case is small relative to the system load. As such, solar DE resources under this case are projected to avoid the highest-cost resources dispatch to serve load – generation from natural gas-fired peaking resources.

Figure 5-3: Typical Summer Day Dispatch, APS Base Case & Low Penetration Case, 2025

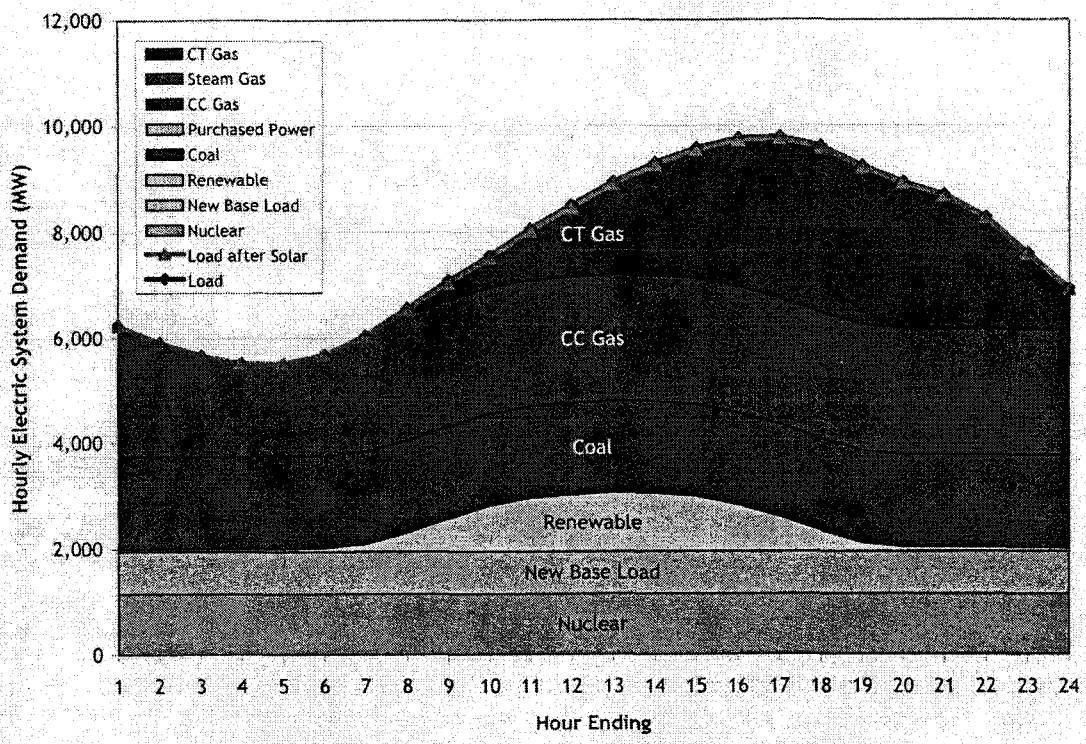


Figure 5-4 depicts the same conditions for the High Penetration Case. As seen in this figure, the solar DE energy under the High Penetration Case is projected to reduce operation of both natural gas-fired peaking and combined cycle resources. As such, while the total cost reduced for the High Penetration Case is larger than that for the Low Penetration Case (produced by the larger quantity of solar energy), the average value of the energy avoided through the High Penetration Case is lower.

Figures 5-3 and 5-4 readily demonstrate a characteristic common to utility resources and programs that reduce load – the most valuable implementations for the utility are typically the first increments installed and each increment thereafter has a lower marginal value to the utility.

Figure 5-4: Typical Summer Day Dispatch, APS Base Case & High Penetration Case, 2025

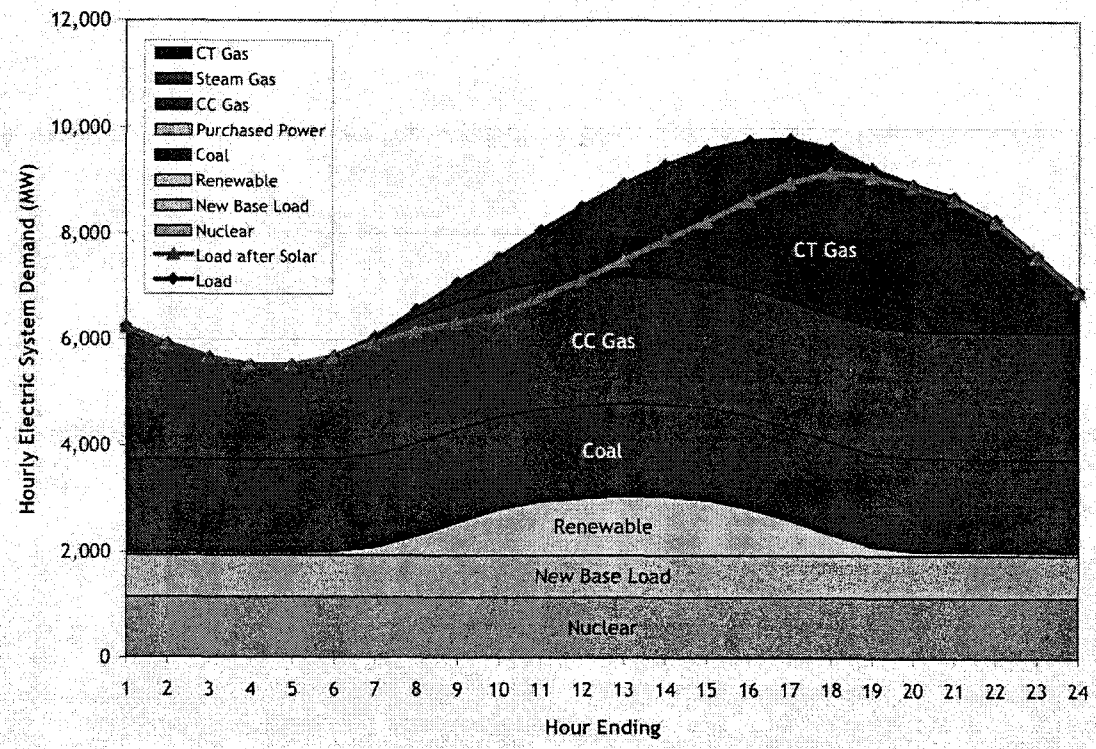
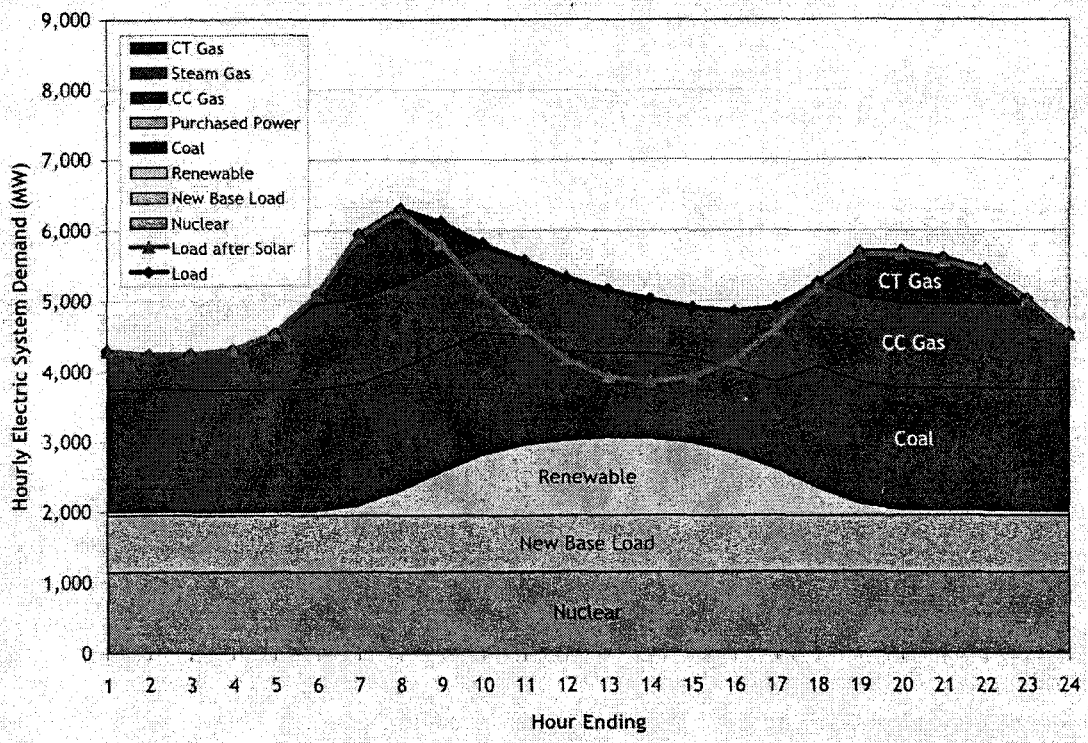


Figure 5-5 depicts resource commitment and dispatch patterns projected for a typical winter day in 2025 for the High Penetration Case. Winter days have load characteristics that are very different than a typical summer day. Winter loads on the APS system tend to peak both in the morning and in the evening, complicating decisions on resource commitment. It is common for utilities faced with a dual daily peak to dispatch intermediate and peaking resources to serve the morning peak and then not need these resources again until the evening peak. While peaking resources can sometimes be started, stopped and restarted in this manner, operating constraints such as minimum permitted cycling times and start costs many times prohibit shutting intermediate resources down during the middle part of the day. As such, as load drops off in the middle of the day, intermediate resources ramp down to their minimum permitted operating capacity and additional generation reductions must come from a lower-cost resource, many times a coal-fired or similar low variable cost resource.

During the winter, the peak output of the solar DE resource is antithetic to the APS system loads in the middle of the day. Solar DE energy is increasing as system load are declining in the late morning, then as load is increasing in the evening, solar DE energy is declining. As such, solar DE energy exacerbates the issues that APS already faces regarding unit commitment and dispatch in the middle of a winter day. Moreover, the variable operating costs that APS can avoid through solar DE energy in the middle of a winter day may reflect a much lower marginal value (may include the cost of coal-fired generation) than experienced during the summer. With

increasing levels of solar DE implementation, APS can expect to experience such diminished value during many more hours and days of the year.

Figure 5-5: Typical Winter Day Dispatch, APS Base Case & High Penetration Case, 2025



5.3.3 Projected Avoided APS Energy Costs

Using the results of the PROMOD dispatch simulation provided by APS, with adjustments as described above, the Study team assessed the value derived for each of the solar DE cases. The avoided energy costs reflect differences in variable operating costs between the APS base case resource plan and each of the solar DE implementation cases, as described in Section 5.2.2. Avoided energy costs reflect changes in fuel costs, variable O&M costs, emissions costs, and power purchases created from changes in resource commitment and dispatch simulated in PROMOD for each of the Study years. Table 5-13 summarizes the results of the avoided energy cost analysis.

Avoided energy costs have been reported for total system energy impacts and incrementally for marginal energy losses. In reality, APS commits and dispatches resources to serve the total electric system load as experienced at the generation level, which includes customer loads with losses. However, since marginal losses are a significant component of the total avoided energy costs for the solar DE resources, a separate tally has been provided for the marginal losses.

Table 5-13
Avoided Energy Costs

	2010	2015	2025
Low Penetration Case			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	17.3	106.2	176.0
Total Avoided Energy Cost, Incl. Losses (2008 $000)	936	5,606	8,547
Average Avoided Energy Cost (2008 $/MWh)	54.13	52.79	48.56
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	1.9	11.3	18.6
Avoided Cost of Marginal Energy Losses (2008 $000)	102	501	701
Average Cost of Marginal Losses (2008 $/MWh)	54.36	44.31	37.67
Medium Penetration Case			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	18.1	180.8	1,788.6
Total Avoided Energy Cost, Incl. Losses (2008 $000)	980	10,100	96,596
Average Avoided Energy Cost (2008 $/MWh)	54.17	55.87	54.01
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	2.0	19.5	188.9
Avoided Cost of Marginal Energy Losses (2008 $000)	108	1,034	8,659
Average Cost of Marginal Losses (2008 $/MWh)	54.90	53.14	45.84
High Penetration Case			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	18.1	180.8	3,862.6
Total Avoided Energy Cost, Incl. Losses (2008 $000)	980	10,100	182,009
Average Avoided Energy Cost (2008 $/MWh)	54.17	55.87	47.12
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	2.0	19.5	390.2
Avoided Cost of Marginal Energy Losses (2008 $000)	108	1,034	14,529
Average Cost of Marginal Losses (2008 $/MWh)	54.90	53.14	37.23
Single-Axis Sensitivity			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	19.1	188.0	4,045.7
Total Avoided Energy Cost, Incl. Losses (2008 $000)	1,031	10,578	188,846
Average Avoided Energy Cost (2008 $/MWh)	54.11	56.27	46.68
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	2.1	20.3	407.2
Avoided Cost of Marginal Energy Losses (2008 $000)	114	1,074	14,925
Average Cost of Marginal Losses (2008 $/MWh)	54.81	53.04	36.66

5.4 Impact of Solar DE on Ancillary Service Requirements

5.4.1 Description of Ancillary Services

In addition to avoiding resource expansion and marginal energy production, solar DE resources may have an impact on system requirements for certain ancillary services. Ancillary services can generally be described as the amount of generating capacity that APS must have committed but constrained from running at optimum output to assure that sufficient reserves are available to meet contingencies that may occur on the system.

Electric utilities are required to provide a variety of ancillary reserves in order to maintain reliable operation of the electric system. These reserves generally fall into the following categories.

- Spinning Reserves – Requirement that each electric utility maintain a certain amount of generating capacity committed (operating) but not fully dispatched so that the utility can instantaneously meet system contingencies, such as the loss of a generator or major transmission interconnection.
- Operating Reserves – Requirement to maintain a certain amount of non-operating (uncommitted) capacity ready to be operated within a few minutes time (typically within 10 to 30 minutes) to handle major system contingencies.
- Regulation Reserves – Portions of committed generating resources that are reserved to meet the moment-by-moment fluctuations in utility loads. Regulation reserves are also used to meet the significant growth and decline in utility loads that occurs each morning and evening, respectively, and sometimes in the middle of winter days (as seen in Figure 5-5).

The concern for solar DE resources is that APS requirements to provide ancillary services may increase as solar DE implementations increase. Spinning and regulation reserves are many times provided by the largest, most efficient dispatchable resources owned by the electric utility. Generating resources that provide these ancillary services must be constrained from operating at their optimum performance, causing total variable cost of the utility to be higher than would otherwise be the case if no ancillary services were required. As a result, if solar DE were to increase APS's requirements for ancillary services, then their value to APS would be diminished.

For instance, a cloud passing over a solar PV array would cause the power output to stop and then resume, causing in turn the load displaced by solar to suddenly increase and then decrease. Such fluctuations in load could require APS to provide for additional regulation reserves anytime the solar DE resource was expected to be operating.

5.4.2 Impact of Solar DE on Spinning & Operating Reserves

APS could incur additional requirements for spinning and operating reserves related to solar DE installations if it was believed that a large portion of the solar DE resources could suddenly stop producing electricity (other than normal daily production patterns), thereby requiring another APS resource to provide the missing electric power.

One likely event that would cause a significant loss of solar DE output is the effect that an approaching storm front would have on solar PV and daylighting systems on the APS system. As the cloud cover associated with the frontal boundary moves across the APS electric system, PV and daylighting installations behind the cloud front would be shaded, thus reducing or eliminating the output from these facilities. The electric load that was originally served by the facilities would now need to be served by other APS generating resources. Similar, although possibly smaller, effects could be experienced from major thunderstorm events or merely increasing cloud cover. If the weather event was unanticipated, it could cause APS to rely on resources providing spinning and operating reserve to make up the shortfall of electric supply from the solar DE resources.

However, discussions with APS reveal that their system operators – APS staff that manage and administer the moment-to-moment operation of the electric system – monitor and predict the impact and timing of storm fronts on the APS system quite well. So long as the system operators have accounted for the quantity of solar DE on the APS system, APS believes that they should be able to reasonably predict the impact of a storm front on solar DE operation and, subsequently, on the electric system. They believe they will be able to commit and dispatch resources sufficient to manage potential adverse effects that weather events may have on solar DE operation and the electric system.

Another possible event that would cause a significant loss of solar DE output was discussed in Section 4 where an under- or over-frequency condition could cause a significant number of inverters for solar PV installations to trip off-line. However, such conditions would be rare since they effectively represent a double contingency event. As a result, PV inverter trips are typically not treated as a condition for which APS is required to maintain reserves.

While there may exist other events that could cause a significant number of solar DE resources to simultaneously stop producing, the two events described are thought to represent the preponderance of potential causes. As such, solar DE installations are not anticipated to result in a significant increase in spinning and operating reserve requirements for APS. However, because the quantity of solar DE electricity production is projected to be greater than the current levels of spinning reserves maintained by APS in some hours, the utility should carefully weigh its ability to predict and manage such events when determining whether to increase its spinning and operating reserve requirements as solar DE levels increase on the APS system.

5.4.3 Impact of Solar DE on Regulation Reserves

Regulation reserves represent the quantity of capacity that APS must have committed and available to meet instantaneous, moment-to-moment variations in load. These variations are generally caused by customer appliances and equipment turning off and on in unpredictable patterns. Much of the variability observed for any individual customer will be mitigated across the electric system since all customer loads do not turn on or off simultaneously. However, net variability in total load can still be large, varying by as much as 2 to 3 percent of the average load within an hour under normal operations. Variability is usually worse in the morning and evening hours when load is growing or declining significantly.

With regard to solar DE installations, the concern is that fluctuations in the output of individual or small groups of solar DE facilities could increase the variability already observed in system loads. Any increase could require APS to carry more regulation reserves, which would increase APS's operating costs. Variability in solar DE facility output could be caused by forced outage events (random electronic or mechanical failures of the solar DE facility) or by weather events, such as a random passing cloud. However, it is also anticipated that the distributed nature of the solar DE installations and the natural non-coincidence of outages that would occur across a large number of solar DE facilities could effectively mitigate the variability that might be observed for any one solar DE resource.

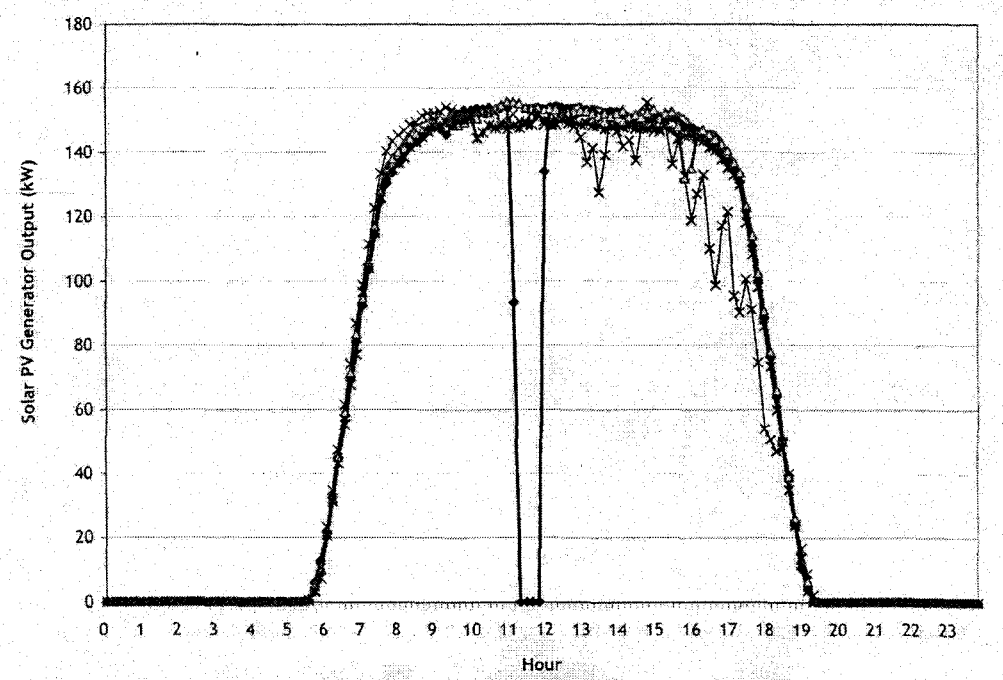
To appropriately evaluate the impact that solar DE facilities have on APS regulation reserves, it would be necessary to track a statistically significant sample of solar DE facilities randomly distributed over the entire APS service area. Data from these facilities would need to be monitored and recorded continuously, down to perhaps one-minute intervals for at least one year.

Such data does not currently exist. However, APS has been tracking data for a small sample of solar facilities in its service area for over a year. While not a statistically viable sample, the data provided by APS was analyzed to determine if any preliminary indications of solar DE facility impacts on regulation reserves could be derived.

The Study team examined the solar facility generation data provided by APS recorded over 2007 for 16 existing solar PV generation facilities located in the APS service area. Data for these facilities was recorded on 10-minute interval basis, which, while longer than appropriate for evaluating regulation reserve requirements, should be sufficient to examine intra-hour variability of solar facility operation. These observations included four installations located in close proximity, which were combined to control for the fact that they would likely be similarly impacted by localized weather conditions.

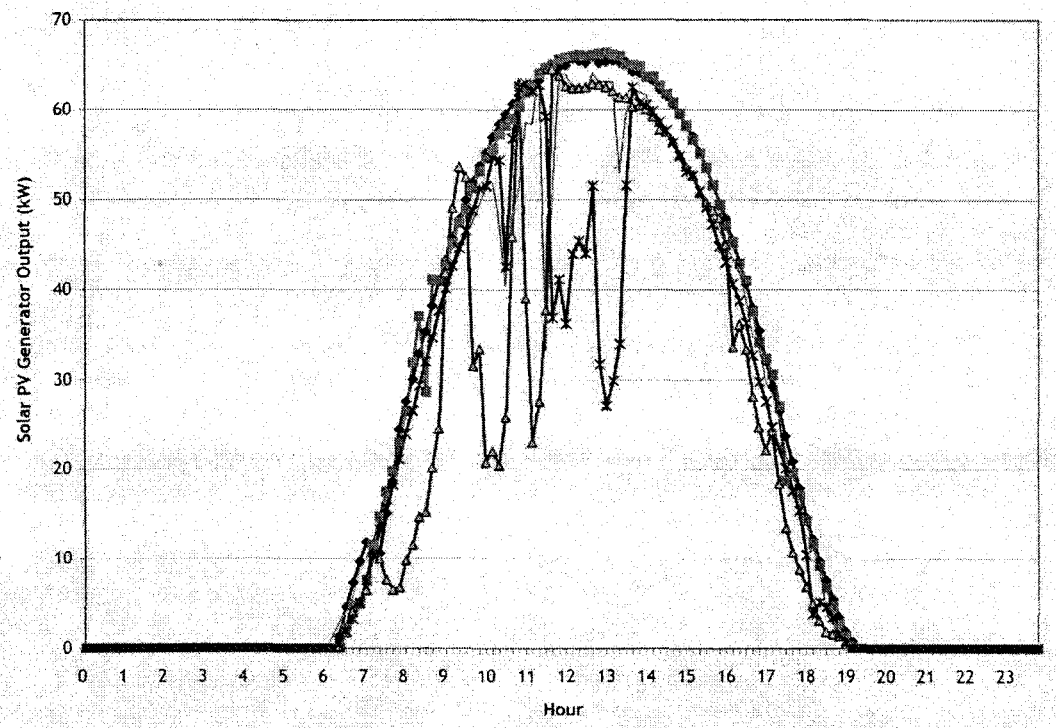
Figures 5-6 and 5-7, below, depict generation output for two selected PV facilities as measured over 10-minute intervals for several consecutive days. The facility depicted in Figure 5-6 is a single-axis tracking installation, while the facility depicted in Figure 5-7 is a fixed plate installation. The lines on these figures represent multiple days of output from the facilities. The specific days are not relevant to the analysis conducted; however, as seen in the figures, significant variability in solar PV output is possible.

Figure 5-6: Typical Output, Single-Axis Tracking PV, Multiple Days, 10-Minute Interval



Note: The output values above represent the "typical" output from a single-axis tracking PV system over multiple days. The specific days represented by the lines above are not relevant to the point that there can be significant variability in solar PV output.

Figure 5-7: Typical Output, Fixed Plate PV, Multiple Days, 10-Minute Interval



Note: The output values above represent the "typical" output from a fixed plate PV system over multiple days. The specific days represented by the lines above are not relevant to the point that there can be significant variability in solar PV output.

To perform the data analysis, the Study team developed an approach that compares the variability of the output of a single monitored installation to the variability of the aggregate output of all available monitored installations. The specific approached used for the analysis is described below:

1. The 10-minute output data for each of the 13 solar facility sites were unitized to the maximum output for any 10-minute interval in each month, meaning that each 10-minute output value within a month was divided by the monthly maximum to achieve a value ranging from zero (0) to one (1). For each site, the unitized data was averaged across each month for each 10-minute interval to achieve a "smoothed output curve." This smoothed curve was then re-based to a unitized shape.
2. The 10-minute output data for each site was also unitized to the daily maximum output to produce daily "normalized output curves" to compare to the smooth output curves. The daily normalized output curves were subtracted from the smooth curves, and the standard deviation of the difference across each month and 10-minute interval was then computed to approximate the volatility of each solar facility's actual output.
3. An aggregate solar output series was also created by averaging the monthly unitized shapes of the individual sites for each 10-minuite interval, which provided for equal weighting

across the generator sites. The resulting aggregate profile was then processed for daily normal and smooth monthly patterns in the same manner as used for the individual sites, from which the difference was computed and analyzed to determine the standard deviation for the aggregate series across each month and 10-minute period.

The analysis showed that the standard deviation of the interval solar output for the aggregate series is approximately one-half that of average standard deviation for the individual solar facilities. This result demonstrates a significant reduction in variability for just the 13 sites distributed across the APS system. It could reasonably be expected that as the number of solar installations increases, the variability of the aggregate sites would continue to diminish. It is also recognized that any measure of variability would likely asymptotically approach some lower limit as generator sites were added to the analysis. In other words, the level of regulation reserves required for the solar DE installations is not likely to be zero; however, insufficient data is available to determine the asymptotic result.

The analysis was also limited by data quality. The solar output data for many of the facilities were missing periodically and, for a few sites, for periods of multiple days at a time. In addition, the data appeared erroneous in limited instances. The analysis was carried out in a manner that effectively excluded or corrected for these instances to a great extent, but undiscovered erroneous data may still have impacted the analysis.

APS should consider expanding its metered solar dataset to permit a more complete analysis of this issue. Alternatively, APS could consider the simulation of geographically distributed, short duration meteorological events, coupled with a solar DE forced outage simulation, and incorporate these simulations within an evaluation of actual APS regulation reserve requirements. Such an analysis could permit a simulation of solar DE impacts on regulation reserve requirements.

A winning business case for solar DE deployment must demonstrate quantitative value and address the many qualitative issues in order to achieve success.

SECTION 6 — DEVELOPING A WINNING BUSINESS CASE FOR SOLAR DE DEPLOYMENT

Arizona's successful solar future requires an alignment between the business considerations, economic drivers, market readiness and societal needs. In order for solar DE to take its place along side traditional thermal resources, a case needs to be developed that supports the expansion of solar DE across residential and commercial markets. The support has to include customer-side issues, such as readiness for product acceptance; utility-side issues, such as system integration; and business-side issues, such as the financial support for solar DE investment.

This section identifies a framework for assessing the value of solar DE deployment in the APS service territory. This assessment is based on the goals, analysis, and current information outlined in this Report. It includes a comprehensive assessment of the benefits to APS, its customers, and other stakeholders, while promoting a sustainable solar DE deployment program in Arizona.

Value has a number of dimensions, some of which are purely economic or engineering based (such as those driven by savings potential), and those which have an element of perception (such as the consumer desire to have a reduced environmental impact). A supportable winning business case needs to take into account both types of value.

The foundation for the assessment in this Study is built upon:

(1) A quantitative evaluation of the savings potential from solar DE deployment under the diverse scenarios defined in this Study.

(2) A qualitative assessment of various factors and measures that could be undertaken to help further solar DE deployment sufficient to achieve the RES objectives in a financially and socially responsible manner.

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Value is also viewed and measured from the varying perspective of individuals, the utility, businesses, and society at large. It is the alignment of multiple perspectives of values that allows for creating a successful and winning business case for solar DE deployment in which all constituencies benefit, or are at least held whole, in the process.

This section of the Report describes the objectives of the valuation task, the approach used to assess the value of solar DE deployment in the APS service territory, the methodology employed, and the results of the task.

6.1 Objectives

A principal objective of this Study is to assist APS in developing a winning business case for the promotion of solar DE technology; one that balances the needs and concerns of APS, its customers, and other stakeholders. A winning business case requires that APS meet its responsibilities to its shareholders and ratepayers while making meaningful progress towards achieving the RES objectives in a financially and socially responsible manner.

For the many diverse interests to support such a program, it is imperative to formulate a broad and solid business case and strategy. This requires developing and evaluating a framework to review the alternative deployment scenarios discussed earlier in this Report; and assessing the benefits of solar DE deployment to APS, its customers, and other Arizona stakeholders while considering the costs and viability of solar DE deployment. The approach used in this Study also considers possible strategies to help APS achieve the RES goals, while enhancing value for the stakeholders. Enhancing value is a key step toward creating a successful solar future for Arizona.

6.2 Approach

The approach used to assess the economic value of solar DE deployment in this Study is relatively straightforward:

- Quantify the savings from avoided or reduced energy usage costs due to solar DE deployment, based primarily on reduced fuel and purchased costs.
- Quantify the savings from reduced capital investment costs resulting from solar DE deployment, including the deferral of capital expenditures for distribution, transmission and generation facilities.
- Estimate the present value of these future energy and capital investment savings due to solar DE deployment.
- Consider the impacts of various qualitative factors that will impact solar DE deployment.

There may well be a myriad of changes happening in the solar industry that will influence solar deployment and value over the next 15 years. Improved technology opportunities, significant cost reductions, research breakthroughs, increased dedication and commitment to renewable options, and many other factors, may prove to have great impact in the future.

The Study team, however, has attempted to remain philosophically aligned with proven and defensible data, technologies and analytics. The purpose of this disciplined approach was to

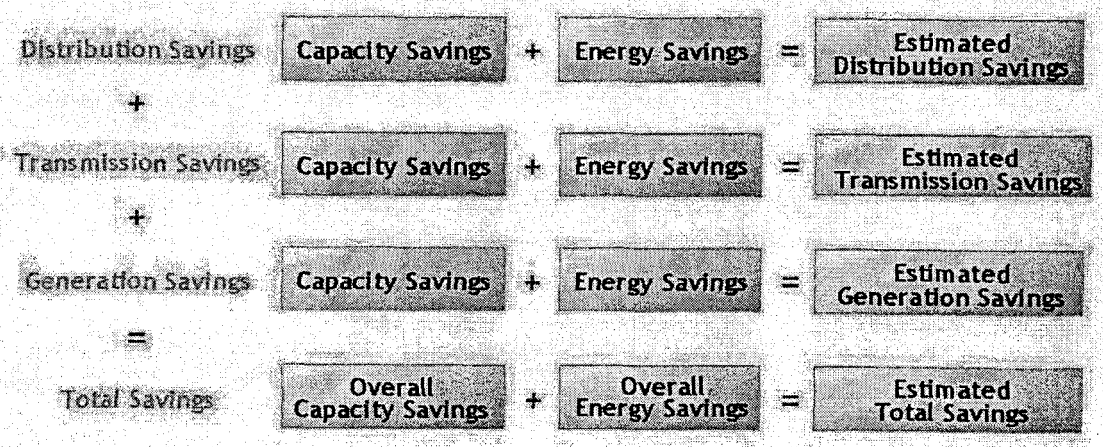
establish a clearly endorsable and unambiguous identification of value for discrete and specific conditions.

It is fully anticipated that APS and others will be able to use this Study as a starting point to form and evaluate other possible scenarios and outcomes which would be appropriate and proper for other forums to explore. Certainly, there are many potential industry pathways. The value of this more confined approach to the quantifiable evaluation of solar DE deployment comes from establishing a solid foundation upon which all parties can then build, and creating a supportable framework for discussion among all parties.

6.2.1 Approach to Quantification of Saving

The approach used in this Study to develop a winning business case for APS starts with the quantified benefits resulting from the potential capacity and energy savings levels found in the Study analyses. The cost savings to APS would arise from two primary sources: future reductions in fuel and purchased power associated with reduced APS energy needs, and future capital investment reductions associated with deferred or avoid APS capacity. These provide the key ingredients of quantifiable savings from solar DE deployment in all three of APS's business sectors—distribution, transmission, and generation – as summarized in Figure 6-1.

Figure 6-1: Quantification of Savings



Certain potential savings associated with various environmental and societal costs and benefits not otherwise captured through regulated emission allowance costs and credits discussed in Section 5 were not explicitly included in this quantification effort. This approach was purposely used in an attempt to keep the Study effort focused on the more readily quantifiable and less speculative savings that are identified in the Study.

6.2.2 Approach to Identification of Qualitative Savings

A second element of the approach included consideration of various barriers to full deployment of solar DE market development and possible strategies to minimize, remove or surmount these barriers. Included in this consideration of important qualitative elements that could impact solar DE deployment in Arizona are the following:

- Clarification of social and institutional obstacles to full solar DE deployment.
- Identification of possible strategies or solutions that APS might take to address these obstacles.
- Non-economic considerations, such as customer conditions and perceptions regarding solar DE.

6.3 Methodology for Quantification of Savings

6.3.1 Quantitative Methodology Used to Value Solar DE Deployment

To estimate an annual economic savings in the target years of 2010, 2015, and 2025 for the APS distribution, transmission, and generation business sectors under the solar DE deployment scenarios, the first step was to separate capacity and energy savings. As previously discussed, this separation was made because capacity savings represent value in terms of either deferral or avoided investment costs by the utility, while energy savings represent both immediate and ongoing cumulative benefits associated with the reduction in energy requirements of the utility.

This methodology is consistent with the revenue requirement approach for capital investment economic evaluations developed by the EPRI more than 30 years ago and widely accepted in the utility industry[1]. The methodology recognizes all elements of a utility's cost to provide service, including energy components (fuel, purchased power, and operating and maintenance expenses and taxes) and capacity components (capital investment depreciation, interest expense and net income or return requirements). It measures reduced or avoided energy and capacity costs that APS will not incur if solar DE is successfully deployed.

Correspondingly, it measures the lower costs that future ratepayers of APS will see, and thus is the key quantifiable measure of value from solar DE deployment.

6.3.2 Value of Energy Savings

Future energy savings associated with solar DE deployment are readily identifiable through the simulation of APS's future costs to meet the energy needs in the target years of 2010, 2015, and 2025. As described in Section 5 of the Report, the operational cost savings for each business unit roll up to reduced fuel, purchased power, and losses associated with reduce production requirements on the APS system following solar DE deployment. Additional reductions in fixed O&M requirements for APS have been quantified and included as annual cost savings in this

[1] For a full description of this EPRI methodology, see the TAGTM Technical Assessment Guide, EPRI TR-100281, Volume 3: Rev. 6, December 1991, especially Section 8.

evaluation. These values were used to estimate annual energy savings and cost reductions for the total entire APS system at energy and operational levels.

As noted earlier, most solar DE savings are realized in terms of energy, as the capacity savings are limited by the time of day of APS's system peak demand, and to a lesser extent, by non-coincidental capacity demand reductions at the local distribution level. From a customer cost perspective, however, residential and commercial customers without demand changes will see the energy portion of their bill reduced as a direct offset for both energy and demand reduction in delivered energy from APS. As such, from an individual customer perspective it is the reduction in energy that is the primary factor in the establishment of value, rendered through reduced utility costs.

From the utility's perspective, however, the energy savings are not as important from a design of view, because the utility still has the responsibility to maintain a system capable of handling peak demand levels of its customers. Although the utility does realize system savings from reduced energy usage in terms of fuel reduction and lower line loses, it is the capacity costs associated with delivery of power at peak demand time periods that generally are of greatest concern to the utility.

The difference in costs and value reflected in these two perspectives – customer versus utility – that creates a considerable constraint on the fair evaluation of solar energy. This is inherently explored throughout this Report and addressed later in this section.

6.3.3 Value of Capacity Savings

The capacity savings associated with solar DE deployment requires a more complicated evaluation framework in order to calculate estimated savings for specific years. The identified reduction or deferral in total capacity investments in distribution, transmission, and power supply for the target years of 2010, 2015, and 2025 were presented in Sections 3, 4 and 5 of this Report. The corresponding annual reduction in APS's revenue requirements resulting from these capacity investment savings are estimated using carrying charges[2] calculated separately for each sector. Moreover, an appropriate carrying charge varies each year for a specific discrete investment made in a particular year. These carrying charges are primarily a function of the accumulated capital recovery or depreciation elements, as well as return on investment rate-base elements. These carrying charges generally decline over time as depreciation accumulates.

Because the specific year of avoided or deferred capital investment is both uncertain and difficult to clearly identify in the case of accumulated solar DE deployment savings, the Study used a levelized carrying charge for each utility sector to provide a reasonable estimate of annual capacity costs associated with capital investments. These levelized capacity carrying charges[3] for the APS distribution, transmission and generation systems are summarized in Table 6-1.

[2] The definition and calculation of the carrying charges for APS used in this study are discussed in Appendix N.
[3] The levelized carrying charge value represents approximately the same value as the 11th or 12th year carrying charge value for assets with 30- to 50-year lives such as most electric utility distribution, transmission, and generation investments entail.

Table 6-1
Levelized Carrying Charge by Functional Sector

	Distribution System	Transmission System	Generation System
All Years	12.06%	11.84%	11.79%

These carrying charges were used along with the capacity investment savings developed in the previous sections of the Report to estimate annual values associated with the avoided or deferred capital investment costs in the distribution, transmission, and generation sectors resulting from solar DE deployment. These annual capacity values were totaled for each sector and were then added to the annual energy and O&M savings for each target year in the Study.

It is possible that a reduction in capacity value can be particularly important in this analysis when the location can be defined and, thus, directly decrease the need for system improvement, removal of constraints or new construction. The ability and desirability of installing solar DE in strategic locations can potentially make a significant difference in the value of the solar DE deployment.

For example, under certain conditions, solar DE systems can affect savings both on energy and capacity value if located on a feeder with a known constraint. However, identifying specific feeders that have the ability to support the required amount of solar DE within APS's service territory could be challenging. This is because the characteristics of the customer types on the feeder typically vary from block to block. Targeting these customer types to install sufficient solar DE may be difficult.

In addition, storage capability had a notable impact on capacity value. SHW can be used to lower line losses and can defer some capacity generation needs, thus offering additional value to the utility. However, this value declines as the weather warms since the difference between incoming water temperature and the desired heated water temperature diminishes.

6.3.4 Total Annual Savings and Present Value of Savings

Annual energy, O&M and capacity savings values for all three sectors were calculated in the target years of 2010, 2015, and 2025. Each of these sector values were then added together to determine the total utility savings estimated to occur in these target years under the various solar DE deployment scenarios. These estimates are presented in both inflation-adjusted (2008 dollars) and nominal (escalated for inflation) terms. These tables provide ranges for the annual savings that would occur under various solar DE deployment scenarios.

The present value of these future energy and capacity savings as of the end of 2008 was calculated using APS's discount rate. This provides a range for the current economic values of the solar DE deployment options. More specifically, it represents a range of the estimated present value for the solar DE deployment scenarios that incorporates uncertainties associated with the various assumptions and time periods for solar DE deployment considered.

A more detailed technical discussion of the methodology and specific calculations used in the assessment of the value of solar DE deployment in provided in Appendix N.

6.4 Study Findings—Quantification of Solar DE Savings

6.4.1 Overview and Summary of Identified Savings

A number of key finding have been drawn during the course of this Study. For example, from a technical perspective, high density of solar DE deployment can allow greater numbers of residential customers to be on a single transformer, thereby representing some savings to the utility. Related to these findings, the Study found that the distribution system design cannot be fundamentally changed to reflect a significant amount of solar since it still needs to be sized to peak load conditions, but importantly that modern solar inverters do not create problems for the distribution system.

Some of the key findings identified in this Study include the following:

- Solar output is not coincident with peak demand for either the customer or the utility. This is critical when considering capacity considerations (either payments or incentives) as the impact is on the energy side of the equation, not capacity in any great measure.
- There is greater coincidence of solar and customer peak production for commercial class than residential class.
- There are diminishing returns as it relates to DE solar deployment (i.e., as the amount of solar DE increases, the incremental benefits decline, in terms of losses, capacity, and production costs).
- Since solar output peaks earlier than the load, steps that can shift solar output to later in the day increase capacity value.
- Single-axis tracking may also add significant value by shifting solar output to later in the day.
- Solar DE has a larger incremental value from losses than simply applying an average loss factor due to the exponential relationship of losses to current.
- Technology changes in solar DE energy storage could help extend solar output to meet APS's system peak.
- Energy storage can increase the capacity value, but at the expense of the capital costs and loss of efficiency associated with storage technologies.
- There is a limitation to the maximum capacity value for solar DE without storage. As the solar DE shifts the peak load hour from 5:00 PM to later, the solar output drops off quicker than the load (due to the setting sun). Therefore, while the peak load occurs later in the day, the contribution from solar DE generation is limited.
- For transmission system planning, there is a minimum amount of capacity that is needed to achieve significant value, which is roughly equivalent to one year's load growth for the area of study. The minimum would typically enable a one-year deferral of transmission related capital additions for that area of study. Dependable capacity below that threshold of one year's load growth has essentially zero capacity value.

6.4.2 Summary of Quantitative Findings

The analysis conducted for this section includes a review of the solar DE values from the previous sections for the distribution, transmission and generation functions. These findings include the value of the potential investment savings from capacity reductions along with fixed O&M savings from the generation system, the total annual energy savings from reduced fuel and purchased power costs due to reduced energy sales and reductions in losses, and the total annual savings (a combination of the two). These values are presented as discounted present value estimates for APS, as well as in nominal values. Analysis results are presented in total aggregate savings perspectives and also in related unit value ($/MWh) terms. The fixed and variable nature of the savings are also presented.

6.4.3 Capacity Cost Savings from Solar DE Deployment

Table 6-2 provides a summary of distribution system capital cost reductions associated with the deployment of solar DE. As noted in the table, no value was determined from the Market Adoption scenario (Low, Medium, and High Penetration Cases). In order to obtain capacity value for significant deferment of distribution investments, the distribution system requires that these solar installations be located on a specific feeder to reduce overloading, as discussed in Section 3. Table 6-2 also provides the marginal increased value associated with the single-axis tracking sensitivity. The first column in Table 6-2 represents the value of the distribution capacity cost reductions in the target years in which they occur. The second column is the carrying charge associated with the distribution functional sector for APS (see Table 6-1 above). The third column is the result of the capacity savings reduction times the carrying charge. As discussed in Section 3, these values are estimated from current capital costs in 2008 dollars associated with current distribution equipment costs.

Table 6-2
Capacity Reductions at Distribution Level (2008 $000)

	Distribution System	Carrying Charge (%)	Associated Annual Savings
Target Scenario			
2010	$345	12.06%	$42
2015	$3,335	12.06%	$402
2025	$64,860	12.06%	$7,822
Single-Axis Sensitivity			
2010	$345	12.06%	$42
2015	$3,450	12.06%	$416
2025	$67,045	12.06%	$8,086

Note: No quantified capacity value was identified for the Low, Medium and High Penetration Cases for the distribution system (see text for discussion).

Table 6-3 provides a summary of transmission system capital cost reductions associated with the deployment of solar DE. Unlike the distribution system, the specific location of the solar DE was not an impediment to obtaining value for the transmission system. However, due to the "lumpy" nature of improvements on the transmission system, as discussed in Section 4, a significant number of solar DE installations would be required to aggregate sufficient capacity demand reduction to avoid or defer transmission system costs. Therefore, the calculated transmission capacity savings values occur only in the last target year (2025) and for the High Penetration Case. As in Table 6-2, the first column represents the value of the transmission capacity savings in 2008 dollars, the second column is the transmission carrying charge, and the third column is the associated annual savings.

Table 6-3
Capacity Reductions at Transmission Level (2008 $000)

	Transmission System	Carrying Charge (%)	Associated Annual Savings
High Penetration Case			
2010	$0	11.84%	$0
2015	$0	11.84%	$0
2025	$110,000	11.84%	$13,024

Note: No quantified capacity value was identified for the Low and Medium Penetration Cases for the transmission system. Additionally, transmission capacity savings reductions are not dependent on specific location, so the Target scenario resulted in the same values as the High Penetration Case. Additionally, the single-axis sensitivity (not shown) did not increase the capacity value associated with transmission.

Table 6-4 provides a summary of generation system capital cost reductions associated with the deployment of solar DE. Similar to the transmission system capacity savings, the specific location of solar DE was not an impediment to determining value for the generation system. Additionally, similar to the transmission system, capacity cost reductions for the generation system require a significant aggregation of solar DE installations, which occur only in the later years of the Study period. Unlike the transmission system however, generation capital cost reductions were determined to exist for the Medium and High Penetration Cases. Similar to the previous tables, the first column represents the value of the generation capital cost reduction in 2008 dollars, the second column represents the generation system specific carrying charge, and the third column represents the resulting associated annual savings.

Table 6-4
Capital Cost Reductions at Generation Level (2008 $000)

	Generation System	Carrying Charge (%)	Associated Annual Savings
Medium Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$184,581	11.79%	$21,762
High Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$299,002	11.79%	$35,252

Note: No avoided capital costs for generation were identified for the Low Penetration Case. Capital cost reductions for generation are not dependent on specific location, so the Target scenario (not shown) resulted in the same values as the Market Adoption scenario - High Penetration Case. Additionally, the single-axis tracking sensitivity (not shown) resulted in the same capital cost reductions as the High Penetration Case.

6.4.4 Annual Energy and Fixed O&M Savings

Table 6-5 provides a summary of the potential annual savings (in 2008 dollars) from a reduction in fuel and purchased power costs resulting from reduced energy requirements and associated reductions in line losses and annual fixed O&M costs. Generally, these savings were found to exist for all deployment cases, with the exception of reduction in fixed O&M costs for the Low Penetration Case. Additionally, the specific location of the deployment of solar DE was not a determinant for these value characteristics.

The values determined for the annual energy savings (including the reduction in losses discussed in Section 4 and the reduction in fuel and purchased power costs discussed in Section 5) are a direct result of the output from the solar DE installations. As more solar DE technologies are installed, the greater these values become. The reductions in fixed O&M costs are related to the reduction in demand for the dependable capacity for the generation analysis (discussed in Section 5). The Target scenario was not included below because the results are identical to the High Penetration Case (because the Target scenario is focused on specific locations of solar DE on the distribution system, which impacts the capacity savings, but not the energy savings). The single-axis sensitivity is included in the table below and results in slightly higher energy savings for all target years in the Study.

Table 6-5
Annual Energy and Fixed O&M Savings (2008 $000)

	Reduction in Losses	Reduction in Fuel/ Purchased Power	Reduction in Fixed O&M Costs	Total Energy Related and Fixed O&M Savings
Low Penetration Case				
2010	$102	$834	$0	$936
2015	$501	$5,105	$659	$6,266
2025	$701	$7,847	$3,728	$12,276
Medium Penetration Case				
2010	$108	$872	$0	$980
2015	$1,034	$9,066	$1,351	$11,450
2025	$8,659	$87,936	$18,946	$115,542
High Penetration Case				
2010	$108	$872	$0	$980
2015	$1,034	$9,066	$1,351	$11,450
2025	$14,529	$167,480	$20,965	$202,974
Single-Axis Sensitivity				
2010	$114	$918	$0	$1,031
2015	$1,074	$9,504	$1,546	$12,124
2025	$14,925	$173,921	$21,444	$210,290

6.4.5 Total Annual Savings

Table 6-6 provides a summary of the total solar DE deployment savings by for the Market Adoption (Low, Medium, and High Penetration Cases), and the Target scenario (this is the sum of the values presented in Tables 6-2 through Table 6-5). The difference between the Market Adoption scenario and the Target scenario is that the later requires that the solar DE to be located at specific feeders.

These results indicate that there is more solar DE deployment savings (both terms of total energy and total value) with higher levels of deployment. The higher dollar savings in the Target scenario represents the incremental benefit to the distribution system related to the location specific installations (shown in Table 6-2). The estimated total energy savings (in MWh) are identical for the High Penetration Case and the Target scenario. The single-axis sensitivity includes marginally higher total savings, for both dollars and energy, which reflects the marginally higher output associated with those systems.

Table 6-6
Total Solar DE Savings (2008 $)

	Total Solar DE Savings (2008 $000)	Estimated MWh Savings	Estimated Unit Savings ($/MWh)
Low Penetration Case			
2010	$936	17,301	$54.13
2015	$6,266	106,196	$59.00
2025	$12,276	176,009	$69.74
Medium Penetration Case			
2010	$980	18,099	$54.17
2015	$11,450	180,777	$63.34
2025	$137,304	1,788,610	$76.77
High Penetration Case			
2010	$980	18,099	$54.17
2015	$11,450	180,777	$63.34
2025	$251,250	3,862,585	$65.05
Target Scenario			
2010	$1,022	18,099	$56.47
2015	$11,853	180,777	$65.56
2025	$259,072	3,862,585	$67.07
Single-Axis Sensitivity			
2010	$1,073	19,061	$56.29
2015	$12,540	187,977	$66.71
2025	$266,652	4,045,697	$65.91

Note: The Target scenario recognizes the contribution to the dollar savings from the capacity cost reductions in the distribution system (which requires specific solar DE locations). However, the energy savings (in MWh) for this scenario is the same as for the High Penetration Case (see text for discussion).

APS presents much of its resource evaluation information in nominal dollar terms. Table 6-7 provides a summary of the same solar DE deployment savings presented in Table 6-6 but in nominal year dollar terms (i.e. including the effects of future inflation estimated at 2.5 percent per year).

Table 6-7
Total Solar DE Savings (nominal $)

	Total Solar DE Savings (nominal $000)	Estimated MWh Savings	Estimated Unit Savings ($/MWh)
Low Penetration Case			
2010	$984	17,301	$56.87
2015	$7,448	106,196	$70.13
2025	$18,679	176,009	$106.12
Medium Penetration Case			
2010	$1,030	18,099	$56.91
2015	$13,611	180,777	$75.29
2025	$208,924	1,788,610	$116.81
High Penetration Case			
2010	$1,030	18,099	$56.91
2015	$13,611	180,777	$75.29
2025	$382,307	3,862,585	$98.98
Target Scenario			
2010	$1,074	18,099	$59.32
2015	$14,089	180,777	$77.94
2025	$394,209	3,862,585	$102.06
Single-Axis Sensitivity			
2010	$1,127	19,061	$59.14
2015	$14,906	187,977	$79.30
2025	$405,743	4,045,697	$100.29

Note: The Target scenario recognizes the contribution to the dollar savings from the capacity cost reductions in the distribution system (which requires specific solar DE locations). However, the energy savings (in MWh) for this scenario is the same as for the High Penetration Case (see text for discussion).

The results shown in Tables 6-6 (2008 dollars) and 6-7 (nominal dollars) demonstrate the reduction in marginal value as total energy from solar DE technology is increased (the "Law of Diminishing Returns" concept discussed in Section 4). As more solar DE technology is installed, the estimated total savings increases (both in the total dollars of savings and the total energy [MWh] savings). However, the increase is not linear and the unit savings ($/MWh) decrease with increased levels of solar DE deployment.

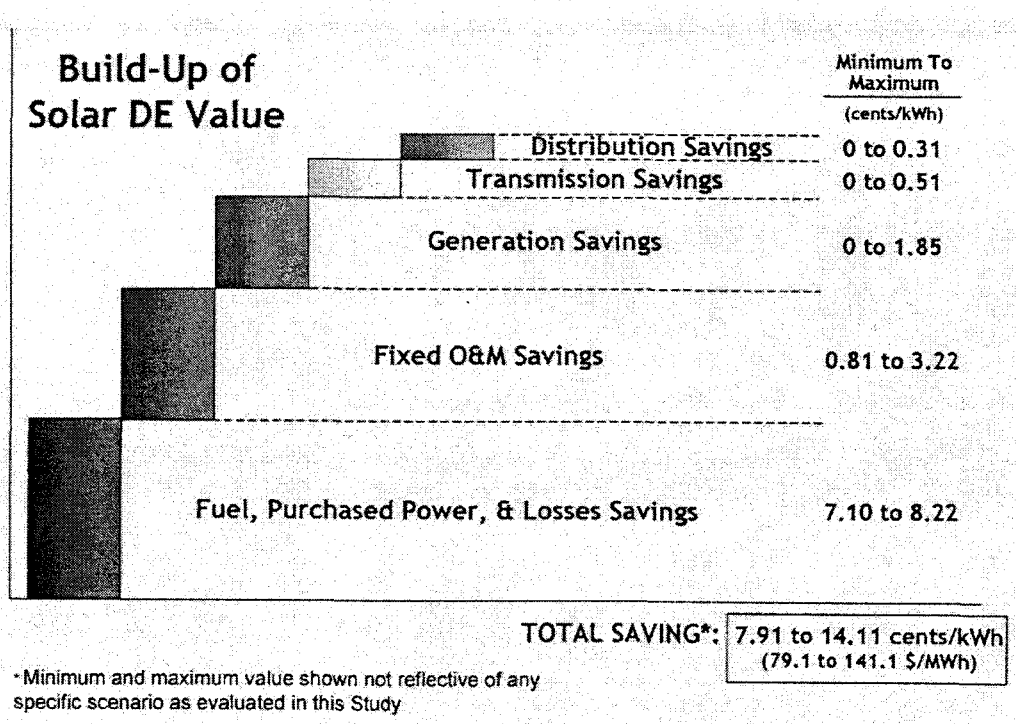
An example of this can be seen in a comparison between the Medium and High Penetration Cases for 2025. The total savings in dollars (both for 2008 dollars and for nominal dollars) is higher for the High Penetration Case, as are the total energy savings (MWh), however, the unit

savings for the High Penetration Case is lower than the Medium Penetration Case ($98.98/MWh compared to $116.81/MWh for the nominal results).

The results also indicate that while there is a higher value associated with the Target scenario compared to the High Penetration Case (due to the capacity reduction for the distribution system), the increase on a unit basis is not significant (approximately 3 percent increase in value on a unit basis). Additionally, the results indicate that the single-axis tracking sensitivity provides marginally higher total solar value (for both dollars and energy) compared to the High Penetration Case; however, the unit savings are marginally lower than those for the Target scenario.

A build-up of the functional elements of the value from solar DE deployment developed in this Study for 2025 are represented graphically in Figure 6-2.

Figure 6-2: Elements of APS's Solar DE Savings in 2025



The build-up of value suggests that the relative magnitude of value varies tremendously, as indicated by the range of values shown in Figure 6-2. These results suggest that the value from the savings in fuel, purchased power and losses is the largest driver of value (ranging from about 90 percent of the total savings at the minimum and about 60 percent of the total savings at the maximum). It should be noted that the build-up of solar value presented above is not confined to any specific deployment, rather it represents the minimum and maximum values determined in year 2025 for all deployment scenarios across the functional areas identified in the Study.

Money

APS explores outsourcing some IT work

by **Ryan Randazzo** - Sept. 4, 2009 12:50 PM
The Arizona Republic

Arizona Public Service Co. is researching what it costs to have computer-programming work done offshore, but a company official said APS has no plans to send jobs overseas.

The move comes as utilities face increasing pressure to keep prices low, but some regulators say using offshore labor might be going too far.

APS has about 400 employees who work in its information-services department, and another 400 or so contractors to augment its staff.

In June, APS asked for quotations from contractors in hopes of finding some new companies that can provide labor and to set standard prices for the work, spokesman Dan Wool said.

APS asked for hourly rates, in U.S. dollars, for workers who can perform a variety of tasks, including areas such as Oracle databases, Web development and help-desk support.

APS specifically asked for the cost of jobs to be performed "offshore" and the cost for those in Arizona.

Already about one-fifth of the 400 contractors working for APS are overseas. But Wool said the bid request was not intended to seek lower offshore labor rates to send work overseas.

"I understand how it would look like that," Wool said. "We are trying to get information on all the different kinds of companies out there and the rates they charge for all kinds of work."

APS issued its request as the other large Arizona utility, Salt River Project, embarked on a similar initiative.

SRP interviewed several outsourcing companies this year, and eventually asked for bids from Accenture Ltd. and Infosys Technologies Ltd. to take over about 50 SRP computer-programming jobs.

Both Accenture and Infosys have a local presence but are based overseas - Accenture in Ireland and Infosys in India.

Some SRP directors, who will have final say in the matter, said they had reservations about outsourcing, but will support it if the savings are significant.

Wool said APS occasionally contracts with India-based Wipro Ltd., and that some contractors might use offshore labor, but that the company was not looking to replace its direct employees.

Wool said the timing of SRP's move to outsource internal jobs and APS seeking offshore rates from contractors is coincidental.

"This is completely different from the SRP situation," Wool said. "The timing is unfortunate. This is a supply-chain process we are going through for our entire organization."

Wool said even if offshore contract-labor rates are less expensive than Arizona-based computer programmers, it does not mean all 400 APS contractor jobs will be offshored.

"Rates are just one of many criteria used when bidding out these jobs," Wool said. "Each has its nuances."

Arizona Corporation Commission Chairwoman Kris Mayes, whose organization regulates APS and other utilities, said the APS price shopping is concerning.

"Obviously, they are asking for these quotes because they think they will be able to find cheaper labor somewhere else," Mayes said. "I don't think that APS and our other utilities have to go looking for workers in India in order to cut costs. I know there are other cost savings APS can engage in without shipping Arizona jobs overseas."

Commissioner Gary Pierce previously said the cost savings to utilities under his jurisdiction would have to be significant for him to support outsourcing work overseas.

Pierce said he did not have enough information about the APS request for offshore bids to weigh in on the subject.

Mayes said she would prefer to see APS cut other expenses such as lobbying, and that the cost savings for using offshore labor do not compensate for the lost jobs in Arizona.

"We are not talking about a competitive industry here," Mayes said. "It is a monopoly utility that is supported by Arizona consumers."

She said there likely are unemployed computer programmers in Arizona who could use the work from APS.

According to the latest report from the Commerce Department, Arizona lost 3,300 information-sector jobs in the last year, a 7.7 percent decline.

"The company has an obligation to do everything it can to keep these jobs in Arizona," Mayes said. "The jobs are being financed by Arizona ratepayer dollars. I have hard time seeing Arizona ratepayer dollars going to India and Ireland."

Reach the reporter at ryan.randazzo@arizonarepublic.com, or (602) 444-4331.

APS's 2009 Renewable Energy Costs

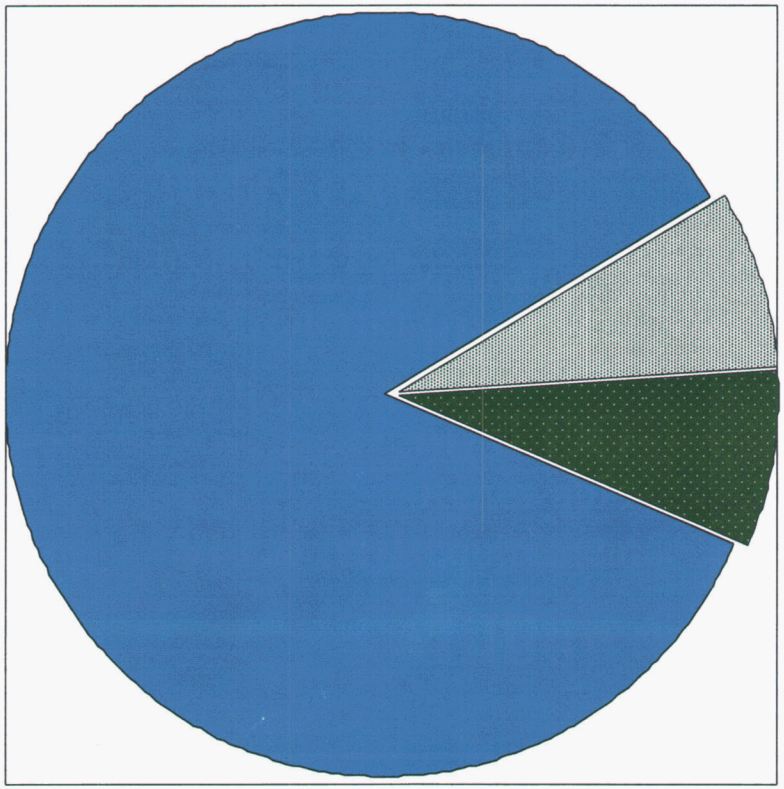
2% requirement = 591 Million kWh

$78.4 Million Total Cost

Utility-Owned or Purchased Renewable Generation

85% of Renewable Energy Requirement

$11.4 Million



Commercial DG

7.5% of Renewable Energy Requirement

$8 Million

Residential DG

7.5% of Renewable Energy Requirement

$57.6 Million

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COMMISSIONERS
KRISTIN K. MAYES - Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

ARIZONA CORPORATION COMMISSION

Gary Pierce
Commissioner

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August 31, 2009

Jeff Guldner
Arizona Public Service
Vice President of Regulations
400 North 4th Street, M.S. 8995
Phoenix, Arizona 85004

Re: Declining Natural Gas Prices; Docket No. E-01345A-08-0172

Dear Mr. Guldner and Parties to the Docket:

I am attaching a news article that ran in the business section of today's *Arizona Republic* regarding the impact that low natural-gas prices is having on electric rates. The article asserts that APS receives about 32% of its annual energy from natural gas generation, whereas SRP receives only 11%. The article also states that, due to the declining cost of natural gas, APS plans to reduce its rates for the average residential customer by about $4.71 in January, and that SRP plans to reduce its rates for the average residential customer by $5.26 in November.

I want this article incorporated into the record, and I want the parties to answer the following questions:

(1) Should the Commission wait until January before adjusting rates downwards to reflect the lower costs of natural gas? If so, why?
(2) Is it true that the amount of energy APS receives from natural gas is approximately three times greater than SRP? If not, what are the appropriate percentages?
(3) If APS receives a larger percentage of its energy from natural gas, why isn't the bill impact associated with the declining natural gas costs greater for APS customers than for SRP customers?

Sincerely,

Commissioner Gary Pierce

cc: Chairman Kristin Mayes
Commissioner Sandra Kennedy
Commissioner Bob Stump
Commissioner Paul Newman
Ernest Johnson
Steve Olea
Rebecca Wilder
Janice Alward

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Pierce 2
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August 31, 2009 | 6:30 am | 88°

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Low natural-gas prices may shrink bills

SRP, APS say they'll bring down some fees; companies will still pursue rate increases

by Ryan Randazzo - Aug. 29, 2009 12:00 AM
The Arizona Republic

The weak economy has deflated natural-gas prices enough that electricity surcharges at Arizona utilities will fall, which could cushion but not eliminate the impact of rate increases.

Arizona Public Service Co. and Salt River Project both pass the cost of natural gas directly to customers with no markup, and the charges move up and down separately from regular rates.

The APS "power-supply adjuster" and SRP "fuel escalator" get tweaked annually, sometimes twice a year, to reflect prices of natural gas for their power plants.

APS plans to reduce its charge by about $4.71 a month on the average home bill beginning in January, Vice President of Regulations Jeff Guldner said.

If APS gets the rate hike it is requesting from regulators, the average home monthly bill would rise $1.22, or 0.93 percent above current rates, because of the fuel decline, he said.

SRP plans to reduce its rates by $5.26 a month on the average home bill in November because of fuel prices, Chief Financial Executive Mark Bonsall said.

SRP is considering a rate increase that would average about $12 a month on homes even with the fuel cut. The rate hike would be more than $17 a month without the fuel cut.

If not for the regular rate increases, utility prices would fall. APS is in regulatory hearings for its increase, and SRP officials are debating theirs.

If and when natural-gas prices rise, the utilities will adjust their fuel surcharges upward.

Natural-gas prices hit a seven-year low on Thursday at the Henry Hub in Louisiana, a key trading point that sets prices on the New York market.

The gas is traded in futures contracts in blocks of a million British thermal units, and the price for one unit fell to $2.69, down from more than $12 a little more than a year ago.

SRP gets about 11 percent of its annual power generation from natural-gas plants and APS about 32 percent.

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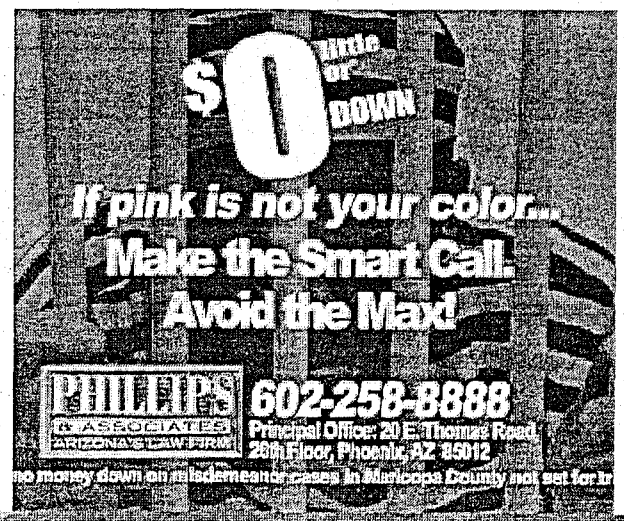

PINNACLE WEST
CAPITAL CORPORATION

LAW DEPARTMENT

MEGHAN H. GRABEL
Senior Regulatory Attorney
Telephone: (602) 250-2454
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September 9, 2009

Kristin K. Mayes, Chairman
Gary Pierce, Commissioner
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Chairman Kristen K. Mayes' September 1, 2009 letter regarding declining natural gas prices and possible acceleration of refund of the over-collections in Arizona Public Service Company's . . . Power Supply and Purchased Gas adjustor account, Docket No. E-01345A-08-0172; Commissioner Gary Pierce's August 31, 2009 letter regarding declining natural gas prices, Docket No. E-01345A-08-0172.

Dear Chairman Mayes and Commissioner Pierce:

This letter responds to various inquiries posed to the parties to the Arizona Public Service Company ("APS" or "Company") rate case in Chairman Mayes' letter of September 1, 2009 and Commissioner Pierce's correspondence of August 31, 2009. Each of those letters primarily asks questions related to whether the current over-collected balance in APS's Power Supply Adjustor ("PSA") should be refunded to customers prior to the proposed January 1, 2010 effective date for new rates. The Chairman also asks that APS state "whether it would be in the public interest to delay the implementation of the base rate increase portion of the proposed APS rate increase for several months," and if not, why not.

APS strongly believes that public policy supports approving the Settlement Agreement as proposed. Consider:

- Coordinating the PSA reset with the implementation of new rates would result in a **less than one percent rate increase** for the average residential customer, providing a smooth transition for needed rate relief.

- Implementing the PSA reset today will not significantly reduce customer bills, which on average will decline considerably in the coming months in any event due to lower usage and winter rates.

Law Department, 400 North Fifth Street, Mail Station 8695, Phoenix, AZ 85004-3992
Phone: (602) 250-2454 · Facsimile (602) 250-3393 · E-mail: Meghan.Grabel@pinnaclewest.com

EXHIBIT
Pierce 3
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- Delaying the rate increase until May would compound the impact of the normal transition to higher summer energy bills.

- Timing the PSA reset with the onset of new rates in January sends more correct price signals to customers, whose current rates do not reflect the costs required to serve.

- Delaying the rate increase would materially alter the balance struck in the Settlement Agreement and jeopardize its other provisions, including APS's equity infusion, renewable energy, and energy efficiency commitments.

The following elaborates on these points and responds to the remaining inquiries posed in your respective letters.

I. Customer interests are best served by timing the PSA reset so that its early implementation corresponds with the proposed rate increase.

The Company recognizes the Commission's discretion concerning when the PSA surplus balance should be credited to customers. Nevertheless, we continue to believe that the public interest is best served by timing the PSA reset to coincide with the effective date of new rates, notwithstanding the current economic recession. The hottest summer months have now passed. With the onset of the cooler season and lower winter rates, customers will see reduced energy bills regardless of a PSA reset. Indeed, the average residential customer bill is more than $73.50 per month less in the winter compared to what it is during the summer. Under the terms of the Agreement, if the fuel balance is used to offset the proposed base rate increase, the average residential bill will actually decrease again by another small amount in January. Residential customers will thus not see any rise in their electric bills from the base rate increase until May, when the normal transition to higher summer rates occurs. And even then, the net annual rate increase resulting from the proposed Settlement Agreement would be less than one percent – a smooth transition for needed rate relief.

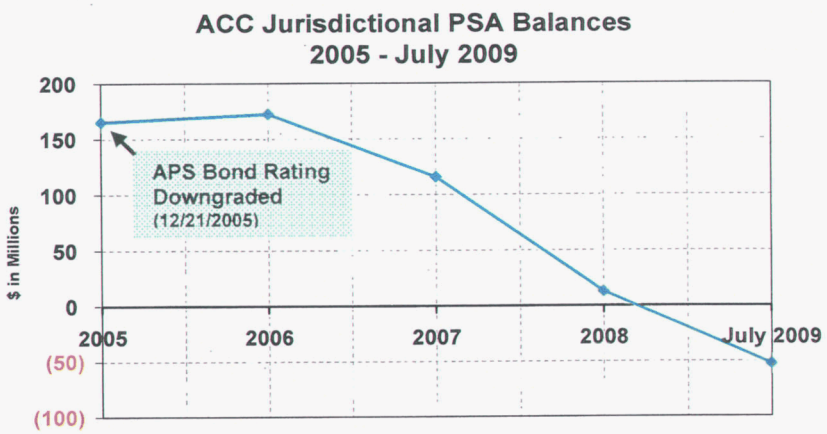
Although resetting the PSA today would reduce the average winter bill slightly (adding a marginal savings of about $1.75 per month[1] to the current $73.50 reduction), doing so will cause it to go up again in January, just a few short months from now, creating rate instability for customers. This is precisely what the parties to the settlement thought best to avoid. In contrast, timing the reset – which is paid back to customers with interest – to coincide in time with new rates would enable the Commission to use the benefit of lower-than-expected fuel costs to almost entirely offset the needed rate increase, giving customers more stability in their electric bills that will help them plan their household budget in these tight economic times. That, APS believes, is a better benefit than saving less than two dollars per month on average for the next few months.

Timing the PSA reset with the implementation of new rates also sends correct price signals to customers, encouraging them to reduce their usage and invest in energy efficiency and similar

[1] This number reflects the PSA balance as of July 2009.

measures to keep their bills down. The prices that customers pay today for electricity do not accurately reflect the overall costs incurred to serve them. To the extent practicable, base rates should send customers market price signals that will shape their usage patterns and better reflect the costs to serve. Delaying the PSA reset until the proposed rate increase is effective, at which time energy prices will be somewhat more aligned with the cost of producing and delivering that energy, will send the right price signals to customers – an important policy consideration.

The fact that the PSA is currently running a credit balance is neither unanticipated nor inconsistent with the structure of the APS fuel adjustor, which was always intended to be, and by its terms is, symmetrical in operation. Prior to the reforms to the PSA ordered by the Commission in the Company's last rate case, continual and significant under-collections impaired APS's financial health, ultimately causing APS's credit rating to be downgraded to its current BBB- status. Past under-collections reached variance levels of upwards of $160 million and $170 million in some years, far exceeding the current $52 million over-collection. The following table shows how the PSA balance has changed over time:



The changes to the PSA authorized by the Commission in Decision No. 69663 resolved many of the cash flow problems caused by the volatile fuel costs experienced by the Company, and the new PSA has been recognized by credit rating agencies as important to the Company's financial health.

Yet even the current PSA, which uses a forward-looking estimate of fuel and purchased power costs to set the adjustor rate, adjusts that balance to reflect actual costs just once each year (on February 1). Although there is a "Transition Component" mechanism in the PSA that allows the Commission to approve a mid-year change to the PSA rate, that device is reserved for "cases where variances between the anticipated recovery [or refund] of fuel and purchased power costs for the PSA Year . . . become so large as to warrant recovery, should the Commission deem such an adjustment to be appropriate." *See* PSA Plan of Administration at 2. If the Commission views a $52 million variance (the current over-collection) as "so large as to warrant recovery," it is empowered to use this mechanism in order to reset rates mid-year. We believe that a mid-year adjustment should be the exception rather than the rule.

In sum, we believe customer and policy interests are best served by aligning the PSA reset with the effective date of new rates. The parties to the Agreement, including residential and commercial customer advocates and Commission Staff, fully considered this issue and agreed that the proposed timing is consistent with the public interest. That said, the Company understands that this is a policy decision for the Commission and respects the Commission's discretion to determine whether or not the adjustment to the PSA is more appropriately made now. If the Commission determines it should be done now, APS will file an application to effect that decision.

II. Delaying the implementation of the base rate increase portion of the proposed rate increase for several months is not in the public interest and would be a material change to the Agreement.

Chairman Mayes next asks the parties to indicate whether it is in the public interest to delay the proposed base rate increase "for several months" in order to allow customers "a reprieve from higher bills." APS believes that the answer to this question is an emphatic "no."

First, delaying the rate increase will not be necessary in order to shield customers from paying materially higher energy bills. As previously discussed, if the Commission agrees with the settling parties that the PSA reset should offset the needed rate increase, customer bills are expected to increase by less than one percent. Customers are not likely to see any noticeable difference between what they were paying on December 31, 2009 and what they will pay on January 1, 2010, if new rates take effect in January as proposed. On the other hand, delaying the effective date by "a few months" means that the rate increase will take effect around May of next year – precisely the time of year when customer bills naturally rise in any event with the return of hot weather and higher summer rates. A rate increase in May would compound the seasonal bill impact customers already face. As a matter of policy, customers are less impacted when rates are increased in the winter or shoulder periods, when naturally lower electric bills ease the transition to the new rate.

Second, this issue should not be characterized in terms of providing a "reprieve" to customers from paying rates that come closer to covering (though still do not fully cover) APS's cost of service. No party to the Agreement disputed the fact that APS's existing rates are insufficient and that accordingly an increase is necessary. Put differently, customers have not been required to pay the true cost of electricity for years. The Agreement, if approved, will not change this. Under the terms of the Agreement, APS has committed to a revenue level that is expected to produce only a 9.4% return on equity ("ROE") in 2010 – 1.6% below the proposed cost of equity. Even if rates take effect in January as proposed, APS will still have a revenue deficiency of $80 million in 2010 (a shortfall that takes into account the Company's commitment to reduce expenses by $30 million per year). Delaying the increase until May 1, 2010 would cause that expected ROE to fall by a full percent – to 8.4% – and would increase the revenue deficiency in 2010 by another $50 million. This result would only compound the $554 million cumulative earnings shortfall that APS has suffered since 2003.

APS's Funds from Operations ("FFO") to Debt ratio would also fall to 17.2% in 2010, below the 18% threshold for investment grade, **in the very first year of the settlement period.** This trend

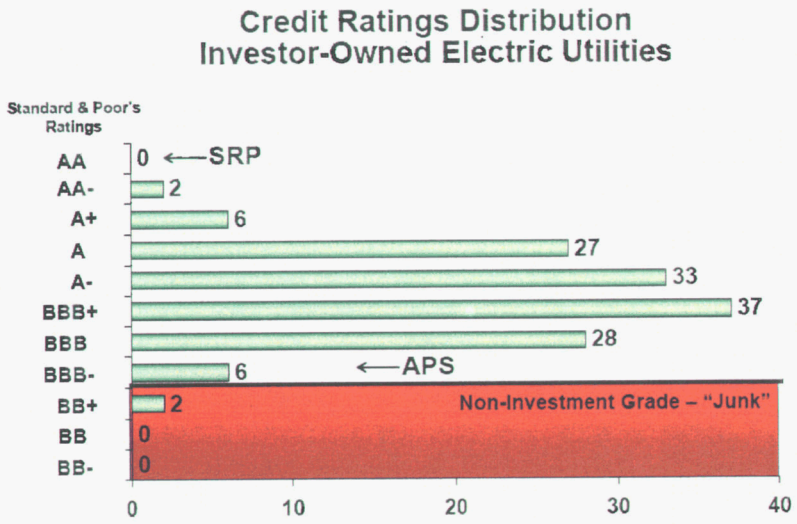
would continue until APS's next rate case, challenging the Company's ability to issue equity under reasonable terms during the intervening years. And there is little doubt that Pinnacle West will be unable to issue equity at all until APS receives a rate increase. Investors are encouraged by the terms of the settlement, but are waiting to see whether it is adopted by the Commission before agreeing to put their money in the Company.

Thus, although delaying the rate increase until May will have a small short-term benefit to customers, it will significantly and adversely affect the Company. Simply put, the economic package provided in the Agreement is the minimum APS needs to be in a financial position to issue equity and to fulfill the commitments it has made in furtherance of Arizona's energy policy. Delaying the increase to May would accordingly be a very material change to the Agreement from our point of view.

III. SRP's situation is significantly different.

In contrast to APS, SRP has the financial capability and flexibility to fashion the amount and timing of its intended rate increases. SRP and APS are two starkly different entities. SRP is a municipal corporation that benefits from tax-free financing, does not pay income taxes, does not pay property taxes (making lower "in lieu of" payments instead), and that has the ability to benefit from preference power and similar legislative advantages not available to APS to lower its cost of service. Not regulated by the Commission, SRP also has the discretion to raise rates using a streamlined process without independent external review and to base those rates on forward-looking costs. In fact, unlike that proposed for APS, SRP's currently contemplated rate increase appears to be based on fiscal year 2011 projections, not just on its historical, actual costs. Although not directly related to its governmental status, SRP also serves a distinctly more compact service area and benefits from higher customer density. As a result of these and other differences between APS and SRP, **SRP has a credit rating of "AA" – higher than any investor-owned utility in the country.**

By contrast, as the following makes plain, APS vies with a just handful of other utilities to be the **third worst** rated investor-owned utility in America.



As a BBB- rated utility, APS simply cannot weather delays in rate relief as well as its AA rated counterpart. Just one step from junk bond status, APS faced challenges in accessing the capital markets in the recent periods of economic distress. When capital became available, the cost of that capital was significantly higher than it would have been had APS been rated AA like SRP, rather than BBB-.

Finally, notwithstanding these relative advantages, SRP reportedly does not intend to delay its full rate increase until mid-next year. SRP plans to raise rates in November by roughly 2.1%, offsetting that increase with a partial decrease in its fuel rates – similar to the Agreement's proposal for APS in this case. Although SRP may delay the balance of its planned rate increase until next year, it also intends to maintain its fuel rates at levels that are not fully adjusted for the lower cost of natural gas. It appears that SRP will retain the surplus in the interim and partially offset a later base rate increase with a second fuel rate decrease.

Put in perspective, this means that, even with SRP's recent change in timing, both APS and SRP will raise rates in the next year. SRP will likely raise them once in November and then once again – perhaps a higher increase – about six months later. If the Commission adopts the terms of the APS Settlement Agreement, APS will receive just one base rate increase in January, offset by PSA reductions. The Company will not be permitted to increase base rates again for another two and a half years. Delaying the rate increase is simply not necessary for APS customers to benefit from the Agreement.

IV. Differences in the bill impact of lower-than-expected fuel costs on APS compared to SRP.

Finally, Commissioner Pierce asks APS to indicate: (1) whether it is true that the amount of energy APS receives from natural gas is approximately three times greater than SRP; and (2) why, if

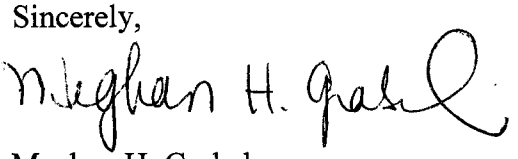
APS receives a larger percentage of its energy from natural gas, the bill impact associated with the declining natural gas costs is not greater for APS customers than for SRP customers.

With respect to the first question, the *Arizona Republic* article correctly noted that natural gas currently comprises about 32% of APS's overall fuel and purchased power resources (assuming all purchases to be from gas resources). APS is uncertain whether the 11% number quoted for SRP reflects the same assumptions. For example, if purchased power were included as natural gas in SRP's portfolio, we believe that percentage may have been larger in 2009. As to the second question, if the PSA reset occurs on January 1, 2010 as the Agreement proposes, rates for the average APS residential customer would go down by about $4.71. According to the *Arizona Republic*, SRP originally intended to similarly reduce its summer fuel rates such that the typical SRP home bill would decrease by about $5.26 in November.

Although it is difficult to precisely isolate the cause of the 55 cent difference, APS believes that it likely results from differences between the manner in which each utility measures its "average residential customer" (SRP's typical customer consumes more kilowatt hours than the average APS residential customer, which would mean the bill impact for a fuel rate reduction would be bigger), differences in each company's hedging practices, and differences in the amount of the over-collection (the more you have to refund, the bigger the refund).

APS welcomes further discussion of any of these items during the hearings.

Sincerely,



Meghan H. Grabel

cc: Commissioner Paul Newman
Commissioner Sandra Kennedy
Commissioner Bob Stump
Ernest Johnson
Steve Olea
Lyn Farmer
Janice Alward
Rebecca Wilder
Parties of Record

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This 9 day of September 2009 to:

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EXHIBIT
FEA-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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-08-0172

DIRECT TESTIMONY

OF

LARRY BLANK

ON BEHALF OF

THE FEDERAL EXECUTIVE AGENCIES

January 8, 2009

IDENTIFICATION

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Larry Blank. My business address is 2533 North Carson St., Suite 3624, Carson City, NV 89706.

Q. PLEASE STATE YOUR PROFESSIONAL POSITION(S).

A. I am the principal of TAHOEconomics, LLC, ("Tahoe") a Nevada-registered consulting company I founded in August 1999, specializing in most facets of regulated utility industries. I also serve (since 2003) on the faculty of the Dept. of Economics and the Center for Public Utilities, both housed in the College of Business, New Mexico State University. For the purposes of this proceeding, I have been engaged through Tahoe.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR BACKGROUND AS IT IS RELEVANT TO THIS TESTIMONY.

A. I have served the public in various capacities for about twenty (20) years. I received a Ph.D. in Economics from The University of Tennessee in 1994, specializing in Industrial Organization & Public Policy (including regulatory policy), Econometrics, and Finance. I previously served as an Economist with the National Regulatory Research Institute and later as the Manager of Regulatory Policy & Market Analysis with the Regulatory Operations Staff of the Nevada Public Utilities Commission. My division's responsibilities in Nevada included tariff and rates analysis for all regulated utilities in that jurisdiction as well as expert witness testimony on the same. As a consultant, I have served a variety of clients including regulatory agencies, utility customers, utility companies, and the U.S. Department of Energy

as the Project Director for technical assistance to the Energy Regulatory Commission in the Philippines. A more complete resume is included as Exhibit LB-1 to my testimony.

Q. WHAT EXPERIENCE DO YOU BRING TO THIS CASE?

A. I have served as an expert witness and/or advisor in over 100 rate cases of various types. I have previously filed written testimony and/or prepared rates-related filings in the following utility regulatory commission jurisdictions: New Mexico, Nevada, Montana, Texas, Arkansas, Hawaii, and the Federal Energy Regulatory Commission ("FERC"). I have served as an advisor to the Maryland Public Service Commission and the Energy Regulatory Commission of the Philippines in rate case proceedings and deliberations. I also teach advanced graduate utility regulation to Masters of Economics students at New Mexico State University who have elected to specialize in this profession, and I help deliver nationally-recognized rate case training programs endorsed by the National Association of Regulatory Utility Commissioners and attended by regulatory professionals from across the United States and abroad.

PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

At the request of legal counsel to the Federal Executive Agencies ("FEA"), I am responding to certain aspects of the cost of service study and rate design proposals filed by Arizona Public Service Company ("APS") in this case. Specifically, I will make recommendations for consideration by the Arizona Corporation Commission ("ACC" or "Commission") on the following topics: Jurisdictional Assignment of Transmission Services Costs; Customer Class Rates of Return; and the proposed Demand Side Management Adjustment Charge.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Jurisdictional Assignment of Transmission Services Costs. The cost of service study sponsored by APS witness Mr. Rumolo lacks consistency and transparency with respect to the assignment transmission services costs and revenues to the FERC jurisdiction. It also is not clear whether the costs associated with key ancillary services have been properly assigned to the FERC jurisdiction. If these observations are correct, the rate of return at present rates has been understated by 0.44%. I also recommend separate accounting of revenues collected from Schedule TCA-1 (Transmission Cost Adjustment) which will make for a cleaner and more transparent separation of the FERC-jurisdictional rates and revenues.

Customer Class Rates of Return. The class rates of return for the General Service and Water Pumping rate classes are significantly above a just and reasonable return. In an attempt to gradually move all classes of customers closer to their respective cost of service, I recommend in this case that the Commission limit any deviation from the final approved just and reasonable return to be no more than 1% (plus or minus).

Demand Side Management Adjustment Charge. The Company has proposed to include an Unrecovered Fixed Costs ("UFC") component in the proposed Demand Side Management Adjustment Charge ("DSMAC") as sponsored by APS witnesses Mr. Pickles and Mr. Delizio. The design of the DSMAC spreads all costs across all customer classes based on energy (kWh) consumption. Applying this design to the UFC component will tend to shift

fixed-cost recovery between rate classes, which is inconsistent with the allocation of fixed costs to rate classes in the general rate case. I recommend that the UFC component be separated from the other components in the DSMAC and independently calculated for each separate rate class as described in Mr. Pickles' direct testimony. I also recommend that the Company be ordered to provide more details on the methodologies to be followed in estimating the kWh impacts of utility DSM programs.

JURISDICTIONAL ASSIGNMENT OF TRANSMISSION SERVICES COSTS

Q. IS THE JURISDICTIONAL ALLOCATION OF COSTS PART OF THE APS COST OF SERVICE STUDY?

A. Yes, it is important to assign or justly allocate costs between the ACC jurisdiction (retail customers) and the FERC jurisdiction (wholesale customers), and this separation of costs is performed within the APS cost of service study. As stated in Mr. Rumolo's direct testimony (pp. 1-2), "[f]orth, I discuss the cost-of-service study prepared to functionalize, classify, and then allocate test year costs and revenues, first between wholesale and retail customers, and then to the various classes of retail service." The adjusted cost of service study was filed in Mr. Rumolo's workpapers as DJR_WP-1.

Q. HAVE YOU REVIEWED THE JURISDICTIONAL SEPARATION OF TRANSMISSION SERVICES COSTS SPONSORED BY MR. RUMOLO IN THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. As explained in Mr. Rumolo's Direct Testimony, "...the revenue requirement for transmission services was computed based on the FERC-jurisdictional rates found in the APS

Open Access Transmission Tariff ("OATT")." (p. 23, lines 19-22). "In this application, the Company proposes that the FERC-regulated charges be removed from base rates and directly charged to customers through a separate transmission rate schedule, TCA-1 [Transmission Cost Adjustment], that would directly incorporate by reference the Company's then-effective OATT charges." (p. 24, lines 3-7).

Q. DO YOU OPPOSE THE COMPANY'S PROPOSED SCHEDULE TCA-1?

A. If all of the related service costs and revenues are directly assigned to the non-ACC jurisdiction in the cost of service study, then I am not opposed to the Adjustment Schedule TCA-1 ("TCA").

Q. WHAT SERVICES ARE INCLUDED IN SCHEDULE TCA-1 AND IS THE COMPANY'S TREATMENT OF EACH OF THESE SERVICES IN THE COST OF SERVICE STUDY TRANSPARENT AND CONSISTENT?

A. Proposed Schedule TCA-1 includes the following five services: 1. Network Transmission; 2. Scheduling; 3. Regulation; 4. Spinning Reserve; and 5. Operating Reserve. Because the TCA utilizes the FERC-accepted rates, these rates are not subject to the ACC's determination; however, the costs and revenues associated with these services are included in the cost of service study and should be assigned to the FERC jurisdiction. The Company has clearly assigned the 100% costs associated with the first two services (Network Transmission and Scheduling) to the FERC jurisdiction but has not assigned the revenues associated with these two services to the FERC jurisdiction (see Note 2, Schedule H-1). Instead, the Company inserts into operating expenses for the ACC jurisdiction what appears to be the revenue requirement for these two services in the amount of $103,578,233 (see Mr.

Rumolo's workpaper DJR_WP-1, p.61, line 36). It is unclear where this number came from because there is no cross-reference in the cost of service study. It is also unclear whether this amount perfectly matches the adjusted revenue for Network Transmission and Scheduling embedded in the ACC-jurisdictional operating revenues (DJR_WP-1, p. 1, line 22), which is used to calculate the Adjusted Operating Income and Current Rate of Return in Schedule A-1, lines 2 and 3, respectively. It would be far more transparent and consistent with the treatment of the costs if the revenues associated with TCA services were separately accounted for and completely assigned to the FERC jurisdiction.

The treatment of the remaining three services (Regulation, Spinning Reserve, and Operating Reserve) is even less transparent because it is not clear whether the costs associated with these services have been assigned to the FERC jurisdiction. At the time of writing this testimony we have pending interrogatories to APS on this subject, and the responses to which may shed more light and possibly modify the testimony that follows. However, I have yet to find an assignment of these costs to the FERC jurisdiction in a manner consistent with the treatment of the first two TCA services. It does appear that the Company included the revenue requirement for these three services ("Ancillary Services") as an operating expense at line 7 of p. 61, DJR-WP-1 in the amounts of $23,527,521 and $1,237,320 for the ACC and FERC jurisdictions, respectively. As in the case of the first two TCA services, this revenue requirement is included as an operating expense because the revenue for these Ancillary Services is embedded in the ACC-jurisdictional operating revenues (DJR_WP-1, p. 1, line 22). As I mentioned earlier, the TCA operating revenue should be separately accounted for and assigned to the FERC jurisdiction. Of greater

1 concern is that there is no indication that the costs of these Ancillary Services have been
2 properly assigned to the FERC jurisdiction.

3 **Q. IS IT NOT THE CASE THAT THESE ANCILLARY SERVICES ARE**
4 **TRANSMISSION SERVICES AND, THEREFORE, WOULD THE COSTS BE IN**
5 **THE TRANSMISSION ACCOUNTS ASSIGNED TO THE FERC JURISDICTION?**

6 A. As defined by the FERC, there are seven transmission ancillary services; namely,
7 Scheduling, System Control and Dispatch Service ("Scheduling"); Reactive Supply and
8 Voltage Control; Regulation and Frequency Response Service ("Regulation"); Energy
9 Imbalance Service; Spinning Reserve Service, and Supplemental Reserve Service (listed as
10 "Operating Reserve" in Schedule TCA-1). Unlike Scheduling, which has its own FERC
11 accounts, Regulation, Spinning Reserve and Operating Reserve services are provided by
12 generation capacity and, therefore, the costs associated with these services are either included
13 in the production accounts or as part of purchased power costs. That is, although these
14 ancillary services are technically "transmission services", the related costs do not appear in
15 the transmission accounts. In recent years, the FERC has mandated a new schedule in FERC
16 Form No. 1 (p. 398), in which the Company must report purchases and sales of ancillary
17 services, including sales to native load retail customers (p. 398 is attached hereto as Exhibit
18 LB-2).[1] However, the costs are accounted for in non-transmission accounts. As I stated
19 earlier, the Company's cost of service study does not specifically assign these costs to the
20 FERC jurisdiction. Regardless of where the costs are recorded, the costs need to be directly
21 assigned to the FERC jurisdiction in a fashion consistent with the Company's treatment of

[1] FERC Order No. 646-A, Docket No. RM03-8-001, June 2, 2004.

1 the transmission accounts and scheduling accounts. Failure to make such a cost assignment
2 will result in double-recovery of these costs.

3 **Q. WHAT ARE THE IMPLICATIONS OF YOUR OBSERVATIONS ON ANCILLARY**
4 **SERVICE COSTS?**

5 A. If the Ancillary Services costs are not directly assigned to the FERC jurisdiction, the total
6 cost of service for the ACC jurisdiction has been overstated by $23,527,521. Assigning these
7 costs to the FERC jurisdiction would increase the adjusted operating income at present rates
8 from $203,111,908 to $226,639,429. Due to this understatement of operating income, the
9 rate of return at present rates for the ACC jurisdiction is understated by 0.44% (at original
10 cost). Therefore, Lines 1-8 of Schedule A-1 would be revised as presented in Exhibit LB-3
11 to my testimony and corresponding changes should be made throughout the APS filing.

12 **Q. DO YOUR OBSERVATIONS RAISE ANY CONCERNS REGARDING THE POWER**
13 **SUPPLY ADJUSTMENT?**

14 A. Yes. The power supply adjustment mechanism (Adjustment Schedule PSA-1) should not
15 include any costs related to Regulation, Spinning Reserve and Operating Reserve otherwise
16 we will see a double adjustment in both in both Schedules PSA-1 and TCA-1 and double-
17 recovery of costs. This may be an issue insofar as any of these costs are included in the
18 Purchased Power Account 555.

19 **Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THIS**
20 **MATTER?**

21 A. Yes. I recommend that the Commission order the Company to begin maintaining separate
22 accounting of the revenues from Schedule TCA-1, itemized by each service and rate class

within the schedule. For the next rate case, these revenues can then be easily removed from the ACC-jurisdictional operating revenues and assigned to the FERC jurisdiction which will avoid the need for the Company to include the revenue requirements for Ancillary Services and Network Transmission and Scheduling Services as it has done in the cost of service study (DJR_WP-1) at p. 61, lines 7 and 36, respectively. This will make for a cleaner separation of FERC-jurisdictional rates and revenues and avoid possible mismatch between the rate-case-adjusted revenues and the revenue requirement for transmission services "computed based on the FERC-jurisdictional rates…" (Rumolo Direct at p. 23, lines 20-21).

CUSTOMER CLASS RATES OF RETURN

Q. DO YOU HAVE ANY CONCERNS REGARDING THE RATE-CLASS RATES OF RETURN BASED ON THE COST OF SERVICE STUDY?

A. The table below presents the Company's proposed percentage rate increases and rates of return by rate class. Also included is the deviation for each rate class from the Company's proposed just and reasonable overall rate of return (8.86% at original cost). Most notable is the General Service and Water Pumping rates of return which are significantly above a reasonable level by at least 1.69% and 4.33%, respectively. In an attempt to gradually move all classes of customers closer to their respective cost of service, I would suggest in this case that the Commission limit any deviation from a just and reasonable return to be no more than 1% (plus or minus) from the final approved rate of return.

Customer Class Rates of Return

Line No.		Proposed Revenue Increase	Proposed Rate of Return	Deviation from "Fair" Return
L1	Overall Company	10.55%	8.86%	TBD
L2	Residential	11.34%	7.62%	-1.24%
L3	General Service	9.71%	10.55%	1.69%
L4	Outdoor Lighting	15.05%	3.15%	-5.71%
L5	Dusk to Dawn	17.30%	9.69%	0.83%
L6	Water Pumping	4.46%	13.19%	4.33%

One way for the Commission to implement my recommendation would be to require that any ordered reductions in the proposed revenue requirements first be used to lower the General Service and Water Pumping customers' proposed rate increase to bring these rates closer to cost of service. This would imply a higher rate of return for the residential rate class, but low-income customers can still take advantage of the APS Residential Energy Support Program (Schedule E-3) which provides for up to a 40% total bill reduction for customers who meet the criteria based on 150% of the Federal poverty guidelines.

DSM ADJUSTMENT CHARGE

Q. HAVE YOU REVIEWED THE PROPOSED DSM ADJUSTMENT CHARGE?

A. Yes, I have reviewed the direct testimonies of Mr. Pickles and Mr. Delizio as well as the proposed Adjustment Schedule DSMAC-1 ("Demand Side Management Adjustment Charge" or "DSMAC").

Q. BASED ON THE DESCRIPTIONS PROVIDED BY APS, DO YOU HAVE CONCERNS REGARDING THIS PROPOSED MECHANISM?

A. The proposed DSMAC includes three components: Program Costs ("PC"), Unrecovered Fixed Costs ("UFC"), and Performance Incentives ("PI"). Fixed costs are those that do not change when kWh sales change; i.e., the demand-related and customer-related costs. My concerns are related to the design of the UFC component of the DSMAC. The primary concern is that the DSMAC is designed to spread all cost components, including UFC, evenly across all customer classes based on kilowatt hour ("kWh") sales. In other words, the decline in fixed-cost recovery in one rate class would be socialized to all rate classes. This is problematic for two reasons. First, a particular DSM program may target a particular rate class or classes more than other classes, thereby causing significant differences in kWh reductions across customer classes. Shifting the fixed cost recovery of the rate class with greater reduction in kWh to other customer classes is inconsistent with established ratemaking principles as will be discussed below. Second, the differences in rate structure and design across rate classes will tend to cause significant differences in the levels of unrecovered fixed costs from one customer class to the next. Specifically, under-recovery of fixed costs due to utility DSM programs is more likely in those customer classes without demand (kW) charges, which ideally are implemented to recover the demand-related costs. While a portion of demand-related costs could be recovered through the customer charge, absent a demand charge, the demand-related costs are typically recovered through the energy charge. In fact, in situations where the customer charge is relatively low – like in APS's residential tariffs – the customer charge isn't even high enough to recover all the customer-related costs. Therefore, all the demand-related costs and a portion of the customer-related costs are recovered through the energy charge.

As stated by Mr. Delizio in his direct testimony,

> "APS rates are designed to recover in each kilowatt hour sold a portion of the fixed costs incurred to serve customers. By their nature, successful energy efficiency DSM programs reduce the amount of energy sales made to customers. Because the Company's rates are volumetric based, i.e., based on the amount of energy customers consume, programs that reduce that volume naturally reduce the amount of net revenue received to pay for fixed costs." (pp. 12-13).

Although Mr. Delizio's statements are accurate, the degree to which fixed cost recovery comes from energy (kWh) rates differs greatly between customer classes. For customers with demand (kW) charges, most of the fixed costs are built into the demand and customer charges, therefore, if kWh sales are reduced, under-recovery of fixed costs is far less likely than for a customer class that does not have a demand charge and also has a relatively low customer charge. In the latter class of customers, most of the fixed cost recovery is through energy (kWh) charges; so if kWh sales decrease, under-recovery of fixed costs is a much greater problem with that class. Therefore, the Company's proposal to spread the UFC evenly across all rate classes based on kWh consumption will tend to shift fixed cost recovery away from those customers without demand charges to those customer classes with demand charges. Fixed capacity costs are allocated to each rate class during a general rate case based, in part, on cost-causation principles. Once the responsibility for fixed cost recovery has been established for each customer class in a general rate case, that responsibility should not be allowed to shift to other customer classes between general rate cases.

Q. DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION REGARDING THE UFC COMPONENT OF THE DSMAC?

A. Yes. The UFC component of the DSMAC should be designed as a separate mechanism and calculated separately for each rate class. That is, each rate class should have its own independently calculated UFC mechanism. This recommendation is consistent with company witness Mr. Pickles' direct testimony (p. 17, lines 2-3) description of Lost Revenue Adjustment Mechanisms ("LRAMs") which involves "[m]ultiplying the net margin component in ***each rate class*** by the DSM sales reductions in ***that class***." ***[emphasis added]*** Failure to design rate-class-specific mechanisms will tend to cause the shifting of fixed-cost recovery responsibility between rate classes, which is inconsistent with the long-standing practice of allocating costs to rate classes based on cost-causation principles.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE PROPOSED UFC MECHANISM?

A. Yes. The Company has been very vague regarding the methodology for determining the kWh impacts of utility DSM programs. The Commission may want to require additional details on those method(s) built into the rules for UFC recovery. So as to not cause delay in this case, the Commission should consider initiating a separate proceeding similar to a rulemaking in which there can be more focused and thorough consideration of all aspects of the DSMAC and to fully develop all necessary details for the tariff or Commission regulations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, thank you.

Larry Blank

Education

Ph.D. in Economics, The University of Tennessee, Knoxville, August 1994.

Dissertation: "Political Economy and Public Utility Inefficiency."
Chair: Professor John W. Mayo (now at Georgetown University).

B.S. in Economics/Mathematics, Bemidji State University, Minnesota, May 1989.

Fields of Concentration

Industrial Organization & Public Policy
Econometrics
Finance (minor)

Professional Experience

Principal Consultant, TAHOEconomics, LLC, August 1999 - Present. Clients have included Government Agencies, Utility Customers, and Utility Companies focusing on most aspects of regulatory policy development and rate regulation in both the telecommunications and energy industries. From Jan. 2002 – Jan. 2005, Dr. Blank also served as the Director of a US Department of Energy grant project assisting the newly formed Energy Regulatory Commission of the Philippines as that agency completely restructured national policy related to the regulation of the electricity industry.

Assistant Professor, Department of Economics & International Business, New Mexico State University (NMSU), August 2003 – Present. Teaching graduate-level public utility regulation, business and government, and antitrust policy/economics.

Senior Associate, Center for Public Utilities, NMSU, August 2003 – Present. Center's training is endorsed by the National Association of Regulatory Utility Commissioners (NARUC).

Manager of Regulatory Policy and Market Analysis, Regulatory Operations Staff, Public Utilities Commission of Nevada, October 1997 - August 1999.

Responsibilities: Directed a ten-person division with duties covering most aspects of utility regulation and competitive restructuring across all industries (primarily telecommunications, electric, and natural gas); implementation of the Telecommunications Act of 1996; division management of all rates and tariffs; lead management of staff's electric and natural gas restructuring activities. Close coordination with legal division in litigated case preparation including lead negotiation experience.

Supervising Economist, Regulatory Operations Staff, Public Service Commission of Nevada, March 1996 - October 1997. Duties similar to those above.

Research Economist, National Regulatory Research Institute, The Ohio State University and the National Association of Regulatory Utility Commissioners (NARUC), September 1994 - March 1996.

Lecturer, School of Public Policy and Management, The Ohio State University (taught Graduate Public Finance).

Published Papers and Reports

"Promotions as Coopetition in the Soft Drink Industry," (with Mike Hyman and Michael Meade). *Academy of Marketing Studies Journal*, Forthcoming, 2008.

"A Dynamic Model of Insurgency: The Case of the War in Iraq," (with C.E. Enomoto, D. Gegax, T. McGuckin, and C. Simmons), *Peace Economics, Peace Science and Public Policy*, Vol. 14, No. 2, (lead author and lead article), 2008.

"The Role of Regulation in Expanding Access to Electricity: Reform in the Philippines," (with Mk Shean), *Energy Update,* Issue No. 4, 2005.

"Open Entry and Local Telephone Rates: The Economics of IntraLATA Toll Competition," (with David Kaserman, John Mayo, and Simran Kahai), *Review of Industrial Organization*, Vol. 14, No. 4, June 2000, pp. 303-319.

"Dominant Firm Pricing with Competitive Entry and Regulation: The Case of IntraLATA Toll," (with David Kaserman and John Mayo), *Journal of Regulatory Economics*, Vol. 14, 1998, pp. 35-53.

"Concavity Assumptions in Regulatory Models and the Capital Waste Controversy," *Journal of Regulatory Economics*, Vol. 9, 1996, pp. 95-100.

"Key Antitrust Pricing Issues for Regulated Industries with Emerging Competition," *NRRI Quarterly Bulletin*, Vol. 17, No. 2, 1996, pp. 279-298.

Telecommunications Service Quality (with V.W. Davis, D. Landsbergen, R.W. Lawton, N. Zearfoss, and J. Hoag), National Regulatory Research Institute, The Ohio State University, Columbus, March 1996.

"Telephone Vouchers: Experiences in Other Markets," *NRRI Quarterly Bulletin*, Vol. 16, No. 4, 1995, pp. 537-547.

Telecommunication Infrastructure Investments and State Regulatory Reform: A Preliminary Look at the Data (with Vivian Davis and Catherine Reed), The National Regulatory Research

Institute, The Ohio State University, Columbus, December 1994.

Considerations in Preparing and Reviewing Socioeconomic Impact Assessments for Low-Level Waste Disposal Facilities (with Mary English, Matthew Murray, and Zoe Hoyle), for the U.S. Department of Energy. National Low-Level Waste Management Program, EG&G Idaho, Inc., Idaho Falls, Idaho: August 1992.

Economic Impact of Chem-Nuclear Systems, Inc. on Barnwell County, South Carolina (with Matthew Murray), for the U.S. Department of Energy. Energy, Environment and Resources Center, The University of Tennessee, Knoxville, November 1990.

Working Papers

"Benchmarking Electric Distribution Utilities in the Philippines," (with Doug Gegax). **Revise and resubmit** at the *Asian Economic Journal.*

"Endogenous Regulatory Constraints and The Emergence of Hybrid Regulation," (with John Mayo). **Revise and resubmit** at the *Review of Industrial Organization.*

"The FERC's Sunk Cost and Original Purpose 'Doctrine' for Existing RTO Transmission Facilities" (with Doug Gegax).

"Can Regulators Stop the Tax Bleeding of Universal Service Support?" (with Bill Smith and Lucinda Blume).

Grants

U.S. Department of Energy, Technical Assistance to the Energy Regulatory Commission of the Philippines, January 2002 – January 2005.

U.S. Department of Energy, Sustainable Energy Development Program (Philippines), January 2005 – August 2005. Completed the Open Access Distribution Service Rules governing 140 electric distribution utilities.

Presentations and Conference Participation

"Can Regulators Stop the Tax Bleeding of the Universal Service Fund?" *Rutgers University Advanced Workshop in Regulation and Competition*, Sky Top, PA, May 2008.

Presentation: "Endogenous Regulatory Constraints and the Emergence of Hybrid Regulation," ***Western Economic Association Meetings***, Seattle, WA, July 2007.

Presentation: "PUHCA Uncertainty...States," ***Western Governors' Association Energy Summit***, Albuquerque, NM, April 15, 2004.

Discussant, ***Advanced Workshop in Regulation and Competition***, Monterey, CA, July 6, 2000.

Presentation: "Nevada Electric Restructuring," ***Western Risk Management & Claims Workshop***, Western Electric Power Institute, San Diego, CA, July 8, 1999.

Discussant, ***Advanced Workshop in Regulation and Competition***, San Diego, CA, July 7-9, 1999.

Participant, ***Danish Ministry Workshop on Telecommunications Interconnection***, Special invitation by the Danish Ministry of Research and Information Technology, London, UK, December 14-15, 1998.

Presentation: "Regulatory Choice: Constraints and Inefficiency," ***Advanced Workshop in Regulation and Competition***, Monterey, CA, July 10, 1998.

Presentation: "Regulatory Choice: Constraints and Inefficiency," ***The 73rd Annual Western Economic Association Conference***, June 29, 1998.

Discussant, ***The 25th Annual Telecommunications Policy Research Conference (TPRC)***, Alexandria, VA, September 27-29, 1997.

Presentation: "Electricity Restructuring Issues," two presentations before the ***Nevada State Senate Committee on Commerce and Labor***, February 1997.

Presentation: "Regulating Market Penetration: A Higher-Powered Incentive Scheme for Local Exchange Companies," ***The Tenth NARUC Biennial Regulatory Information Conference***, Hosted by the National Regulatory Research Institute at The Ohio State University, Columbus, September 11, 1996.

Presentation: "Regulating Market Penetration: A Higher-Powered Incentive Scheme for Local Telephone Companies," ***The Advanced Workshop in Regulation and Public Utility Economics***, Hosted by the Center for Research in Regulated Industries at Rutgers University, Lake George, NY, May 30, 1996.

Presentation: "Balancing Seemingly Conflicting Goals through a Minimum Subscribership Plan: Economic Efficiency and the Risks Borne by Regulators," ***The 27th Annual Conference of the Institute of Public Utilities***, Williamsburg, VA, December 12, 1995.

Presentation: "The Minimum Subscribership Plan (MSP): Quality, Prices, and Current Policy," ***The 23rd Annual Telecommunications Policy Research Conference (TPRC)***, Solomons, MD, October 2, 1995.

Presentation: "A Positive Theory of Price-Cap and Rate-of-Return Regulation: Substitutes or Complements?", ***Southern Economic Association Meetings***, Orlando, FL, November 22, 1994.

Journal Referee

The American Economic Review, April 1995.

Case Participation (partial list)

Electricity:

NV PUC, Docket No. 95-9022, Nevada Electric Restructuring Investigation (several extensive comments).

NV PUC, Docket No. 96-6013 and 96-6014, Sierra Pacific Power Company tariff filing to allow negotiated contracts (testimony).

NV PUC, Docket No. 96-7020, Nevada Power Company Deferred Energy Case (testimony).

NV PUC, Docket No. 97-5034, Rulemaking to establish standards of conduct and related requirements for distribution companies and affiliates.

NV PUC, Docket No. 97-6008, Nevada Power Company's Resource Plan (evaluation of load forecasting).

NV PUC, Docket No. 97-8001, Investigation of issues to be considered as a result of restructuring of electric industry (extensive comments and testimony on all restructuring issues including the development of new regulations).

NV PUC, Docket Nos. 97-11018 and 97-11028, Proposed Unbundling Methodologies of Sierra Pacific Power Co. and Nevada Power Co. (testimonies).

NV PUC, Docket No. 97-10004, Nevada Power Company□s Green Power Tariff (testimony).

NV PUC, Docket No. 98-8034, Nevada Power Company, Application to Designate Unbundled Services as Potentially Competitive (testimony).

NV PUC, Docket No. 98-9038, Regulatory Operations Staff, Application to Designate Unbundled

Services as Potentially Competitive (testimony).

NV PUC, Docket No. 98-7023, Sierra Pacific Power Company and Nevada Power Company, Joint Application for Approval of Merger (testimony).

NV PUC, Docket No.s 98-12007 and 12009, Sierra Pacific Power Co. And Nevada Power Co. Applications for authorization to provide potentially competitive services through affiliates (testimony).

NV PUC, Docket No. 99-4019, Utility.com, Inc., Application for Licensing as an Alternative Seller (testimony).

NV PUC, Docket No. 99-10049, Petition for Advisory Opinion, Rules that may or may not apply to master-metered mobile home parks after restructuring of electric and natural gas markets, (testimony).

TX PUC, Docket No. 22349, Application of TX-NM Power Company for approval of unbundled cost of service rates (testimony filed).

Philippines Department of Energy and Energy Regulatory Board, Electricity Ratemaking Training and Rulemaking for Restructured Wholesale and Retail Electricity Industry (July 2000 – February 2001).

Philippines Energy Regulatory Commission, Project Director and key advisor for over three years on policy development related to industry restructuring and over 140 rate unbundling cases.

Philippines ERC, design of Open Access Distribution Services Rules.

Vermont Department of Public Service, Cost of Service analysis related to Green Mountain Power Corp.

AR PSC Docket No. 06-101-U, Application of Entergy for Changes in Electric Rates (testimony on behalf of the Federal Executive Agencies).

FERC Docket No. EL-07-101, AEP Protest of PJM Cost Allocation and Transmission Rate Design (testimony filed).

Natural Gas:

NV PUC, Docket No. 97-5034, Rulemaking to establish standards of conduct and related requirements for distribution companies and affiliates.

NV PUC, Docket No. 97-8002, Investigation into alternative form of regulation for natural gas local distribution companies and alternative sellers of natural gas, and related matters (extensive comments and testimony on all restructuring issues including the development of new regulations).

***Telecommunications*:**

NV PUC, Docket Nos. 96-3002 and 96-3003, Nevada Bell's Entry into a Plan of Alternative Regulation (testimony).

NV PUC, Docket No. 96-9035, Investigation into Procedures and Methodologies to Develop Costs for Bundled or Unbundled Telephone Services (comments, testimony and cost analysis).

NV PUC, Docket No. 96-4041, Nevada Bell Petition on Confidential Nature of Telecommunications Cost Studies (testimony filed).

NV PUC, Docket No. 97-5018, Investigation into the impact of the Telecommunications Act of 1996 on Universal Service in Nevada (comments).

NV PUC, Docket No. 97-5027, Central Telephone Company-Nevada, tariff filing requesting an increase in directory assistance rates (testimony and cost analysis).

NV PUC, Docket No. 96-8035, GTE, Depreciation Filing (testimony).

NV PUC, Docket No. 97-11017, Virtual Hipster Corp., Petition to terminate rural exemption of Churchill County Telephone Company (testimony).

NV PUC, Docket No. 98-6004, Nevada Bell, Unbundled Network Element Costs (testimony).

NV PUC, Docket No. 98-6005, Sprint of Nevada, Unbundled Network Element Costs (testimony).

NV PUC, Review of Interconnection and Resale Agreements between Incumbent Local Exchange Carriers and Competitors for approval in Nevada.

NV PUC, Docket Nos. 98-10015 and 99-11007, Nevada Bell Arbitrations on the issue of reciprocal compensation and Internet service provider traffic.

Case No. CV771923, Superior Court of the State of California (Santa Clara), Worldcom v. Co-net Communications, Oral Expert Witness Testimony on potential service development including cost and revenue estimates, damage estimate, standard of care in circuit disconnect, and other circuit contractual issues (deposition and oral testimony), April 2000.

FCC CC Docket No. 00-247, Petition for Arbitration, Developed Unbundled Costs and Interconnection Agreement on behalf of Virtual Hipster Corp., December 2000.

NV PUC, Docket No. 00-7012, Nevada Bell Petition for order commencing a proceeding to determine new costs and rates for unbundled network elements (testimony filed on behalf of wholesale customers).

NM PRC, Case No. 05-00094-UT, Qwest Corporation's Amended Alternative Form of Regulation Plan, (testimony filed on behalf of Qwest regarding computation and appropriateness of refund).

Line Extension Policy and Contribution in Aid of Construction, expert witness work on behalf of 3 Rivers Telephone Cooperative, before the Montana Eighteenth Judicial District Court, Cause No. DV-04-731, March 2006.

MT PSC, Docket No. D2005.6.105, Investigation on Use of Federal Universal Service Funds (testimony filed on behalf of PSC advocacy staff).

Exhibit LB-2

2007 APS FERC Form No. 1, p. 398

Purchases and Sales of Ancillary Services

20080420-8034 FERC PDF (Unofficial) 04/18/2008

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	16,160,724	MWh	1,860,081	18,155,292	MWh	2,272,039
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	13,977,132	MWh	6,736,313	13,977,132	MWh	7,073,141
4	Energy Imbalance				-18,068		-676,977
5	Operating Reserve - Spinning	13,977,132	MWh	15,404,976	13,977,132	MWh	16,173,465
6	Operating Reserve - Supplement	13,977,132	MWh	1,947,885	13,977,132		2,068,453
7	Other						
8	Total (Lines 1 thru 7)	58,092,120		25,949,255	60,068,620		26,910,121

APS08763

Exhibit LB-3 (Revised Schedule A-1)
Direct Testimony of Larry Blank
ACC Docket No. E-01345A-08-0172

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2007
(Thousands of Dollars)

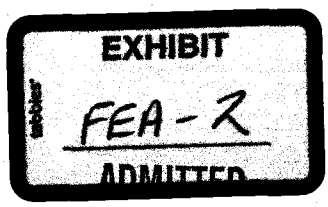
Line No.	Description	Electric Original Cost	Electric RCND	Electric Fair Value	Line No.
1.	Adjusted Rate Base	$ 5,359,964 (a)	$ 10,066,668 (a)	$ 7,713,316	1.
2.	Adjusted Operating Income (Revised)	226,639 (b) **	226,639 (b)	226,639 (b)	2.
3.	Current Rate of Return	4.23%	2.25%	2.94%	3.
4.	Required Operating Income	474,893	474,893	474,893	4.
5.	Required Rate of Return	8.86%	4.72%	6.16%	5.
6.	Adjusted Operating Income Deficiency	248,254	248,254	248,254	6.
7.	Gross Revenue Conversion Factor	1.6491 (c)	1.6491 (c)	1.6491 (c)	7.
8.	Requested Increase in Base Revenue Requirements	$ 409,396	$ 409,396	$ 409,396	8.

	Customer Classification	Company-Projected Revenue Increase Due to Rates	% Increase	Total Projected Revenue Increase Net of PSA	% Increase Net of PSA	
9.	Residential	232,650	17.27%	152,791	11.34%	9.
10.	General Service	207,600	16.74%	120,383	9.71%	10.
11.	Irrigation	3,121	12.30%	1,132	4.46%	11.
12.	Outdoor Lighting	3,372	19.41%	2,614	15.05%	12.
13.	Dusk-to-Dawn	1,451	19.36%	1,297	17.30%	13.
14.	Total APS-Requested Increase in Base Revenue Requirements	$ 448,194	16.99% *	$ 278,217	10.55% *	14.
15.	Total Sales to Ultimate Retail Customers	$ 2,637,447 (d)				15.

Notes
* The $448.2M revenue increase requested above for base rates includes $183.9M due to the Company's request to increase the base fuel rate from 3.25¢/kWh (as authorized in Decision No. 69663) to 3.88¢/kWh. $170.0M of the increase associated with the base fuel increase would have been charged to customers under the provisions of the PSA. Therefore the effective increase to customer rates net of the reduced PSA charges is actually 10.55% or $278.2M. This increase could be further reduced by approximately 2% if the proposed Impact Fee is approved to recover a portion of the proposed revenue requirement related to the attrition proforma adjustment.

Supporting Schedules
(a) B-1
(b) C-1, page 2 of 2. **Revised to reflect direct assignment of Ancillary Service costs to FERC jurisdiction.
(c) C-3
(d) H-1

Recap Schedules:
N/A



BEFORE THE ARIZONA CORPORATION COMMISSION

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-08-0172**

DIRECT TESTIMONY

OF

LARRY BLANK

ON BEHALF OF

THE FEDERAL EXECUTIVE AGENCIES

IN SUPPORT OF
THE PROPOSED SETTLEMENT AGREEMENT

July 1, 2009

1 **Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.**

2 A. My name is Larry Blank. My business address is 2533 North Carson St., Suite 3624, Carson
3 City, NV 89706.

4 **Q. PLEASE STATE YOUR PROFESSIONAL POSITION(S).**

5 A. I am the principal of TAHOEconomics, LLC, ("Tahoe") a Nevada-registered consulting
6 company I founded in August 1999, specializing in most facets of regulated utility industries.
7 I also serve (since 2003) on the faculty of the Dept. of Economics and the Center for Public
8 Utilities, both housed in the College of Business, New Mexico State University. For the
9 purposes of this proceeding, I have been engaged through Tahoe.

10 **Q. DID YOU PREVIOUSLY FILE WRITTEN TESTIMONY IN THIS DOCKET?**

11 A. Yes. I prepared pre-filed written testimony in this proceeding dated January 8, 2009.

12 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

13 A. At the request of legal counsel to the Federal Executive Agencies ("FEA"), I have prepared
14 this written testimony in support of the *Proposed Settlement Agreement,* dated June 12, 2009.

15 **Q. DID YOU PARTICIPATE IN THE SETTLEMENT DISCUSSIONS LEADING UP TO**
16 **THE FILING OF THE PROPOSED SETTLEMENT AGREEMENT?**

17 A. Yes, I participated in several of the many settlement discussions prior to the filing of the
18 *Proposed Settlement Agreement* ("Agreement").

19 **Q. HAVE YOU REVIEWED THE FILED AGREEMENT?**

20 A. Yes.

21 **Q. WHAT IS YOUR OPINION OF THE AGREEMENT?**

22 A. The Agreement nicely balances the various interests of the signing parties in this proceeding.

Q. DO YOU BELIEVE THE RATES, TERMS AND CONDITIONS CONTAINED IN THE AGREEMENT ARE JUST AND REASONABLE?

A. As an entire package, the rates, terms and conditions in the Agreement are just and reasonable.

Q. DO YOU BELIEVE THE RATES, TERMS AND CONDITIONS CONTAINED IN THE AGREEMENT ARE CONSISTENT WITH THE PUBLIC INTEREST?

A. Yes. Nothing in the agreement strikes me as inconsistent with the public interest.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, thank you.

LUBIN & ENOCH, P.C.
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Attorneys for Intervenors
IBEW Locals 387, 640 & 769

EXHIBIT
IBEW-1
ADMITTED

RECEIVED
2008 DEC 19 A 11:20
AZ CORP COMMISSION
DOCKET CONTROL

ADMITTED

BEFORE THE ARIZONA

CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-08-0172 **NOTICE OF FILING DIRECT TESTIMONY OF SAMUEL ELLIOTT HOOVER II**

Pursuant to the Chief Administrative Law Judge's Procedural Order (p. 3) dated July 29, 2008, Intervenors Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"), Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640"), and Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769"), by and through undersigned counsel, hereby provide notice of its filing of the attached Direct Testimony of Samuel Elliott Hoover II in this docket.

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///

RESPECTFULLY SUBMITTED this 19th day of December 2008.

LUBIN & ENOCH, P.C.

Nicholas J. Enoch, Esq.
Attorney for Interveners
IBEW Locals 387, 640 & 769

Original and thirteen (13) copies
of Interveners' Notice filed
this 19th day of December, 2008, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing
transmitted electronically or
via regular mail this same date to:

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Hearing Division
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Testimony of Samuel Hoover II

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Samuel Elliott Hoover II. My business address is 5818 North 7th Street, Suite 201, Phoenix, Arizona 85014.

Q2. PLEASE DESCRIBE YOUR RECENT EMPLOYMENT.

A2. I am the elected President of Intervenor Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"). I have held this position since 2001 and before that I was a member of IBEW Local 387's Executive Board for three (3) years.

On December 17, 2008, I addressed and answered questions from this Commission regarding Arizona Public Service Company's ("APS") request for interim rate relief and the IBEW Locals' support thereof. Included therein, I discussed my background with IBEW Local 387 and APS. For the sake of brevity, I would like to incorporate herein, by reference, my comments to the Commission. As soon as a transcript of my remarks is prepared, I will have it filed with the Commission as Exhibit A to this testimony.

Q3. WHO IS IBEW LOCAL 387?

A3. IBEW Local 387 is a labor organization which, for the most part, represents non-managerial utility workers throughout most of the State of Arizona. For example, IBEW Local 387 is the duly elected and recognized exclusive bargaining agent for a substantial number of

employees of Arizona Water Company, Asplundh Tree Expert Company, Graham County Electric Cooperative, Inc., Navopache Electric Cooperative, Inc., and the Santa Cruz District of UniSource Energy Corporation. IBEW Local 387 is also the duly elected and recognized exclusive bargaining agent for approximately two-thousand three-hundred (2,300) employees of APS. IBEW Local 387 and APS have entered into a long series of collective bargaining agreements ("CBA") dating back to 1945 concerning rates of pay, wages, hours of employment, and other terms and conditions of employment. Our current CBA with APS has been extended to April 1, 2010.

Q4. DO YOU BELIEVE APS IS A RESPONSIBLE CORPORATE CITIZEN?

A4. Absolutely. While by no means perfect, the relationship between IBEW Locals 387 and APS is one which is mature, stable and in accordance with the mission of IBEW Local 387, a copy of which is attached hereto as Exhibit B. It is clear that this stability has enured to the benefit of APS, its employees, and customers. In my opinion, the importance of the relationship between a public service corporation and its employees cannot be overstated. I firmly believe that my opinion in this regard is shared by the executives at APS.

Q4. WHO IS IBEW LOCAL 640?

A4. Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640") is a sister local of IBEW Local 387. While IBEW Local 640 represents some employees outside of the electrical/utility industry, it would be fair to say that IBEW Local 640's primary interest in this case is in its role as the supplier of highly-skilled employees to the Palo Verde Nuclear Generating Station ("Palo Verde") through an International Maintenance Agreement. This agreement was entered into between Bechtel Power Corporation ("Bechtel"), the contractor for APS's construction workers at Palo Verde, and the Building and Construction Trades Department, AFL-CIO, its constituent International Unions, and their affiliated Local Unions. Bechtel has recognized the Unions as the sole bargaining agents for all employees in the classifications covered in their respective agreements that will be working on the project. Currently, IBEW Local 640 also provides employees to APS as part of a task force assembled to assist in underground construction in residential housing developments. IBEW Local 640 is currently providing approximately sixty (60) electricians to this task force.

Q5. WHO IS IBEW LOCAL 769?

A5. Like IBEW Local 640, Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769") is another of our sister locals. IBEW

Local 769 is a labor organization which represents non-managerial utility workers throughout the State of Arizona. For example, IBEW Local 769 is the duly elected and recognized exclusive bargaining agent for the employees of the Mohave County Electric Operations of UniSource, Mohave Co-Op, Frontier Communications and Dynegy (Griffith Power Plant). In addition, IBEW Local 769 is the exclusive bargaining agent for all IBEW outside line workers in the State of Arizona and its scope of work also includes tele-data, street light and trenching. For example, IBEW Local 769 has recently provided outside line construction work for APS through Argent Construction, Inc., Wilson Construction, Klondyke, NPL, Henkels & McCoy and Sturgeon Electric. Currently, IBEW Local 769 is providing bargaining unit employees to Argent Construction, Inc. for the installation of sub-transmission lines for APS. At any given time, IBEW Local 769 will have anywhere from five (5) to two-hundred (200) of its bargaining unit employees working for subcontractors of APS.

Q6. ARE IBEW LOCALS 387, 640, AND 769 SEPARATE LEGAL ENTITIES?

A6. Yes. In addition, it is well-settled that our International Union and its constituent local unions, including my own, are also separate legal entities. That being said, the various IBEW Local Unions in the State of Arizona meet on a regular basis to discuss

issues of mutual concern and, general speaking, we are familiar with and supportive of the actions of each other.

Q7. DO IBEW LOCALS 387, 640, AND 769 HAVE A STAKE IN THIS PROCEEDING OTHER THAN IN THEIR CAPACITY AS LABOR ORGANIZATIONS?

A7. Yes. As building owners in APS's service territory, each of the Locals fall within the definition of a "small-business" customer under the E-32 Rate Plan - *i.e.*, the standard plan for APS commercial customers who have a demand of less than 3,000 kilowatts a month.

Q8. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A8. I am testifying in support of APS's Application for a hate hike.

Q9. WHY IS THE PROPOSED RATE HIKE IN THE PUBLIC INTEREST?

A9. Any public service corporation is entitled to a fair rate of return on the fair value of its property, no more and no less. IBEW Locals 387, 640, and 769 firmly believe that APS's request rate hike meets this test.

As you know, Article XV, §3 of the Arizona Constitution expressly states that the interests of public service employees are on par with those of patrons. It reads as follows:

> The corporation commission shall have

> full power to, and shall... make reasonable rules, regulations, and orders, by which such [public service] corporations shall be governed in the transaction of business within the State, and... make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the ***employees*** and patrons of such corporations[.]

It goes without saying that it costs a substantial amount of money for a public service corporation to hire, train, and maintain a highly skilled work force. Similarly, it costs a great deal of money for any public service corporation to preserve the safety and health of its employees and patrons. Unlike APS's rates - at least until yesterday - the wages paid by APS to its employees and indirectly the employees of its contractors have continued to rise over the past few years. Given the aging of APS's workforce and, indeed, the utility workforce in general, it is critically important that APS have the financial ability to attract and retain a highly skilled workforce. This is particular true if APS continues to grow at even a fraction of the rate that it has in

recent years. As to this point, I fully agree with Donald E. Brandt's observation in his direct testimony (p. 55) that "[e]xhortations to 'work harder' and 'work smarter' cannot change the fundamental nature of increasing marginal costs of serving an ever growing base of customers." Our International President, Edwin D. Hill, made similar points in his 2008 State of Our Union address regarding the utility sector, the webcast of which is available at www.ibew.org/sou-cbs/index.asp.

In these tremendously difficult economic times, I am certain that many in the public may not understand, or want to understand, the need to raise their electric rates, in part, for this reason but I can assure you, APS is competing for a talented workforce, particularly when it comes to linemen, substation electricians and those working in generation. Unlike most of the national and local economy, this is one portion of the job market where demand outpaces supply. Unless APS has the ability to provide a highly competitive employment package, you can be assured that APS and, in turn, the public will suffer. I hope that this Commission and the other parties, including most notably the Residential Utility Consumer Office, bear this is mind. For in my opinion, it is in the "the

interests of residential utility consumers"[1] to have a highly skilled workforce providing safe and reliable service even if that means that they are paying, what they believe to be at least, something more than rock-bottom prices for electric service. To this end, IBEW Locals 387, 640, and 769 believe that the rate relief proposed in this case will help ensure that APS will be able to meet its commitments to its employees and customers in the years to come.

Q10. DOES THIS CONCLUDE YOUR TESTIMONY?

A10. Yes.

F:\Nick\aaaNick'sMasterWorkingFiles.dir\PLEADING\IBEW.pld\L387.PLD\IBEW1445-074.HooverTestimony#1.pld.wpd

[1] *See* A.R.S. §40-462(A).

Exhibit A

To be added at a later date

Exhibit B

IBEW387.COM

Our Mission

Strengthen SOCIAL SECURITY for Working Families

IBEW For Worker Representation

ARIZONA STATE AFL - CIO

IBEW LOCAL 387'S MISSION

Our local stands for quality of life, protection of human rights, individual accountability, and promotion of employment and job stability for all workers.

We recognize that for our local to prosper and grow, so must our companies. Therefore, we will find ways to further the interests of our membership, other employees, our companies, and the public.

To do this, we will promote, support and where necessary demand:

- aggressive organizing
- needed work place changes of mutual advantage
- a safe work environment for all
- sensitivity to diversity
- a highly skilled and productive work force
- an understanding of labor's essential role in the workplace of the future.

SAFETY

The safety of our members, co-workers and the public is a paramount concern at IBEW Local 387, and will be evident by our commitment to safe work practices, training and tools.

We will promote safe and reasonable methods of work. We will continue to promote effective safety training and share innovative safety practice ideas throughout our membership.

DIVERSITY

The members of IBEW Local 387 are our greatest asset. Our success in the future will largely depend on our ability to recognize and respect our cultural differences.

We will recognize each brother and sister as being different, yet equal, and value the differences.

We will respect and be knowledgeable about these differences.

We will be committed, qualified, flexible and willing to educate and inform our members in order to ensure diversity.

ORGANIZING

To organize all workers in the electrical industry, within our jurisdiction, into IBEW Local 387.

We will by legal and proper means promote a higher standard of living through organized labor.

We will cultivate feelings of friendship and brotherhood/sisterhood among those of our industry.

We will seek to promote an understanding of our values, goals, direction and commitment regarding the work force in our industry and to the general public.

COMPETITIVE COMPANY

We recognize that the successful growth of our companies is beneficial to both IBEW Local 387 and our companies.

We believe a strong Union benefits our members' employers.

We will demand and aggressively demonstrate the need to maintain a qualified, knowledgeable and technically superior work force to ensure the production of a reliable high-quality product that enables our companies to be competitive in the rapidly changing and growing marketplace.

AGGRESSIVE ORGANIZING

To organize all workers in the electrical industry, within our jurisdiction, into IBEW Local 387.

We will by legal and proper means promote a higher standard of living through organized labor.

We will cultivate feelings of friendship and Brotherhood/Sisterhood among those of our industry.

We will seek to promote an understanding of our values, goals, direction, and commitment regarding the work force in our industry and to the general public.

MUTUAL ADVANTAGE

The Local Union agrees for its members that they will individually and collectively perform loyal and efficient work and service; that they will use their influence and best efforts to protect the property of our companies and its service to the public; and that they will cooperate in promoting and advancing the welfare of our companies and the company's growth as a strong competitor in the utility industry.

UNDERSTANDING OF LABOR'S ESSENTIAL ROLE IN THE WORK FORCE OF THE FUTURE

We, as IBEW Local 387 members, must recognize that labor's role in the future work force depends on our adaptability, flexibility, and everyone recognizing our diversity.

We will demand a safer work place and we will continue to protect employee rights.

We recognize that a strong union benefits the company ... a strong union means a strong company.

We will demand to be involved in all decision making processes that will create a more positive work environment.

QUALITY OF LIFE

We will continue to seek a higher and higher standard of living for the Brothers and Sisters of IBEW Local 387 by securing competitive wages, benefits, and reasonable working hours.

Our Brothers and Sisters continued employability will be a result of vigorous and aggressive training and skill development.

PROTECTION OF HUMAN RIGHTS

The leadership, officers and membership of IBEW Local 387 must demand that safe working conditions, organizing, fair and equitable treatment, and dignity on the job are note negotiable conditions.

The membership as a whole must seek the proper means to elevate the moral, intellectual and social conditions of our members, their families, dependents and the community toward a higher standard of citizenship.

PROMOTION OF EMPLOYMENT AND JOB STABILITY

Our goal is to increase employment at our companies through growth and production with the most qualified labor force in the electrical industry.

We will cooperate with our companies to train and promote skilled employees within the membership of IBEW Local 387 and through this effort our companies can grow and provide more job stability in the work place of the future.

INDIVIDUAL ACCOUNTABILITY

The Local Union agrees for its members, that they will individually and collectively perform loyal and high quality work and service; that they will use their influence and best efforts to protect the property of the companies and its service to the public; and that they will cooperate in promoting and advancing the welfare of the companies and the protection of its service to the public at all times.

EXHIBIT
IBEW-2
ADMITTED

LUBIN & ENOCH, P.C.
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Attorneys for Intervenors
IBEW Locals 387, 640 & 769

RECEIVED

2008 DEC 30 P 12: 50

AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA

CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-08-0172 **NOTICE OF FILING EXHIBIT A TO THE DIRECT TESTIMONY OF SAMUEL ELLIOTT HOOVER II**

To: Applicant Arizona Public Service Company, *et al.* and their attorneys.

NOTICE IS HEREBY GIVEN that on the date set forth below, Intervenors Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"), Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640"), and Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769"), by and through undersigned counsel, hereby provide notice of their filing Exhibit A to previously filed Direct Testimony of Samuel Elliott Hoover II in this docket.

///

RESPECTFULLY SUBMITTED this 30th day of December 2008.

LUBIN & ENOCH, P.C.

Nicholas J. Enoch, Esq.
Attorney for Intervenors
IBEW Locals 387, 640 & 769

Original and thirteen (13) copies
of Intervenors' Notice filed
this 30th day of December, 2008, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing
transmitted electronically or
via regular mail this same date to:

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Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

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Lyn Caglio

Exhibit A

1 BEFORE THE ARIZONA CORPORATION COMMISSION

2

3 IN THE MATTER OF THE APPLICATION OF) DOCKET NO.
ARIZONA PUBLIC SERVICE COMPANY FOR) E-01345A-08-0172
4 A HEARING TO DETERMINE THE FAIR)
VALUE OF THE UTILITY PROPERTY OF)
5 THE COMPANY FOR RATEMAKING PURPOSES,)
TO FIX A JUST AND REASONABLE RATE OF)
6 RETURN THEREON, AND TO APPROVE RATE)
SCHEDULES DESIGNED TO DEVELOP SUCH)
7 RETURN.)
) OPEN MEETING

8

9

10

At: Phoenix, Arizona

11

Date: December 17, 2008

12

Filed: DEC 22 2008

13

14

15 **REPORTER'S TRANSCRIPT OF PROCEEDINGS**

16 **AGENDA ITEM U-20**

17

EXCERPTS OF PROCEEDINGS

18 **(Pages 246 through 267, inclusive.)**

19

20 **ARIZONA REPORTING SERVICE, INC.**
Court Reporting
21 Suite 502
2200 North Central Avenue
22 Phoenix, Arizona 85004-1481

CERTIFIED COPY
23 (When in red)

By: Kate E. Baumgarth, RPR
Certified Reporter
24 Certificate No. 50582

Prepared for:
25 **IBEW Locals 387, 640, 739**

1 BE IT REMEMBERED that an Open Meeting was held at
2 the Arizona Corporation Commission, 1200 West Washington
3 Street, Phoenix, Arizona, commencing at 10:00 a.m., on the
4 17th day of December, 2008.
5
6
7 BEFORE: MIKE GLEASON, Chairman
WILLIAM MUNDELL, Commissioner
8 JEFF HATCH-MILLER, Commissioner
KRISTIN K. MAYES, Commissioner
9 GARY PIERCE, Commissioner
10 LINDA HOGAN, Secretary
11
12 APPEARANCES:
13 AGENDA ITEM NO. 20
14 For Arizona Corporation Commission Staff:
15 Ms. Janet Wagner
Mr. Charles Hains
16 Mr. Ernest Johnson
17
For Arizona Public Service Company:
18
Mr. Thomas L. Mumaw
19 Mr. William J. Maledon
20 The Arizona Investment Council:
21 Mr. Michael M. Grant
22
For the Residential Utility Consumer Office:
23
Mr. Daniel Pozefsky
24
25

1 APPEARANCES CONTINUED:

2
Freeport-McMoRan and Arizonans for Electric Choice &
3 Competition:

4 Mr. C. Webb Crockett

5
For Mesquite Power, LLC; Southwestern Power Group II, LLC;
6 and Bowie Power Station, LLC:

7 Mr. Lawrence V. Robertson, Jr.

8

9 For IBEW Locals 387, 640 and 769:

10 Mr. Nicholas J. Enoch

11

12

13 KATE E. BAUMGARTH, RPR
Certified Reporter
Certificate No. 50582

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1 that this Commission would take whatever appropriate
2 action that would be required.
3 COM. MAYES: Thank you.
4 CHMN. GLEASON: Okay. Board is clear. Thank
5 you.
6 MR. CROCKETT: Thank you.
7 CHMN. GLEASON: Next in line.
8 MR. ENOCH: Good afternoon. Chairman Gleason,
9 members of the Commission, again, my name is
10 Nicholas Enoch. I appear before you today on behalf of
11 three separate locals of the International Brotherhood of
12 Electrical Workers.
13 Local 640 is a construction local, which
14 provides, through contractors, services to APS.
15 Local 769 is a local, which represents, again,
16 contractors, but they do the basically power line
17 construction and maintenance.
18 The third local, which numerically actually is
19 the first, is Local 387. Local 387 is the certified
20 representative of approximately 2,300 APS employees.
21 And we, collectively the three, intervened, I
22 think it was granted in October. So we didn't even
23 participate earlier on in the September hearings.
24 I can tell that you all three locals vigorously
25 usually support APS's request for interim rate relief, and

1 much in the way that Mr. Maledon kind of passed it off to
2 Mr. Grant, with me today is Sam Hoover, who is the
3 president of Local 387, which is the one that represents
4 more than 2,000 APS employees.
5 Frankly, I think it would be a good opportunity
6 to hear from Mr. Hoover, instead of myself, regarding some
7 of the issues we heard about earlier today about cash
8 balance planning, pensions, layoffs and the like.
9 So if the Chair would be so inclined, I would
10 prefer to turn it over to Mr. Hoover to share his
11 sentiments and directly to respond to any questions from
12 the Commission.
13 CHMN. GLEASON: That's fine.
14 MR. ENOCH: Thank you.
15 MR. HOOVER: Mr. Chairman, members of the
16 Commission, my name is Sam Hoover. I work for Arizona
17 Public Service Company. I also am the president of IBEW
18 Local 387. We represent over 2,000 members under a
19 collective bargaining agreement with Arizona Public
20 Service Company.
21 And it's our position today that we support the
22 APS interim rate increase. We feel that if the Company's
23 bond rating goes to junk, that it's going to inevitably
24 cost our customers millions of dollars of interest, and
25 it's also going to take a long painful time for Arizona

1 Public Service Company to dig ourselves out of the junk
2 bond status.
3 We feel that APS needs to provide competitive
4 wage schedules, not only to the officers of the company,
5 but also to our bargaining members. We obviously have
6 very highly-skilled members out there, journeymen linemen,
7 journeymen electricians, substation electricians, and also
8 our generation side of the house.
9 As some of the Commissioners have mentioned
10 today, we are dealing with an aging work force, and that
11 is a big concern of ours, an aging work force. And with
12 the younger generation, you don't have them wanting to
13 step into the roles that we currently do today for Arizona
14 Public Service Company or with any utility company across
15 the nation. And I just feel that we will compound this
16 measure with -- by not granting an interim rate increase.
17 Due to a -- to allude on Mr. Brandt's comments,
18 the Company is doing a lot of cost cutting. Mr. Brandt
19 and Mr. Bennett came down to our executive board and told
20 us in depth that this was going to be a painful process.
21 We have eliminated jobs. We have eliminated hundreds of
22 jobs in the Union.
23 I think either Commissioner Mayes or Commissioner
24 Mundell talked about, you know, layoffs. That was one
25 thing that we together didn't want to have happen to

1 Arizona Public Service Company. Years ago those -- there
2 was layoffs. Those are a very painful process.
3 We did everything in our power to hopefully
4 prevent and ward off a potential layoff. I have to answer
5 to 2,000 members. We did some serious discussion,
6 consolidations that our membership isn't happy about, but
7 they understand the tough economic times that we are all
8 facing today.
9 So with that being said, you know, I just want to
10 leave you with one thought, that the Company has gone to
11 great extents to cut costs and take care of its customers.
12 During our growth period, as you are well aware,
13 these officers were under great stress to navigate a very
14 challenging climate to meet our customers' needs through
15 this growth period. The infrastructure needed to be
16 built. Arizona Public Service Company couldn't control
17 that growth -- the growth was out in places I never
18 thought I would see growth around in this state of
19 Arizona. We had to build that infrastructure, and we have
20 to maintain that infrastructure today. And that takes
21 highly-skilled competent workers to deliver a safe,
22 reliable product to our customers.
23 So that is what I would like to leave you, the
24 Commissioners, and also the Chairman with.
25 COM. MAYES: Thank you, Mr. Hoover, for being

1 here and sitting through the whole day.

2 MR. HOOVER: No problem.

3 COM. MAYES: Sometimes our meetings can be a

4 painful process.

5 MR. HOOVER: They are interesting, though.

6 COM. MAYES: And I know your meetings are, too.

7 I have been to some IBEW meetings and some other union

8 meetings.

9 You know, I think that the executives sitting

10 here are very lucky to have such a supportive union, but I

11 do want to ask you some tough questions, and recognizing,

12 you know, that the union has, obviously, already taken a

13 hit.

14 You heard what I said earlier when I was talking

15 to the executives. It seems to me that the folks who have

16 taken a hit in the company are the average workers but the

17 executives haven't done much to cut costs in their own

18 ranks.

19 Doesn't it strike you as odd that this company

20 has increased the number of officers and managers and

21 directors, has increased their salaries, has increased

22 their bonuses, and that there has been apparently no cuts

23 in any of those areas, at the same time they asked you

24 guys to take -- to cut back?

25 MR. HOOVER: To your question, Commissioner

1 Mayes, I have got a lot of respect for the officers of
2 this company and what they have guided this company
3 through. I'm very privileged and honored to work for such
4 a good company.
5 I have all the respect in the world and all of
6 our employees do in these officers, and personally I feel
7 that they earn every dime that they make.
8 And I am not going to question their salaries.
9 They do a tremendous job. And they have navigated us
10 through some very challenging times, and they are doing it
11 right now.
12 COM. MAYES: So you think it's okay to continue?
13 Do you think that the ratepayers of this company would
14 agree with you, that it's okay for this company, and in a
15 time of emergency, for the executive officers to be
16 increasing their bonuses, increasing their salaries,
17 increasing their numbers? Do you really think that that
18 is appropriate?
19 MR. HOOVER: I think that -- like Mr. Brandt
20 said, I think that all those need to be looked at in a
21 very prudent manner.
22 COM. MAYES: Well, with all due respect, sir, I
23 don't know what that means.
24 In the last two years they haven't cut costs in
25 any of those areas, and yet you're standing in front of us

1 asking us to increase rates and they're asking us to
2 increase rates. And it strikes me that that is a very odd
3 situation.
4 So it doesn't strike you as odd at all that no
5 cuts have been made in those areas, even in light of this
6 ongoing emergency at the company?
7 MR. HOOVER: Well, like I said before, I have got
8 a lot of respect for them and the adversarial
9 relationships that they have had out there and dealing
10 with the growth of this state and everything. I support
11 what they get, and I'm not here to question what they get.
12 You know, I understand that when this cycle turns
13 back around, you know, that we -- the union will get jobs
14 back. You know, this is one of the sacrifices. I'm not
15 up there on the 20th floor, but I'm telling you what, I
16 have got the utmost respect for the officers on the 20th
17 floor.
18 COM. MAYES: Thank you.
19 CHMN. GLEASON: Mr. Hatch-Miller.
20 COM. HATCH-MILLER: Thank you. I appreciate you
21 being here today. Thank you for stepping for,
22 Mr. President.
23 And I appreciate you mentioning that it's hard to
24 bring people into this industry now. They are not just
25 sitting out there and begging to come in. This is a hard

1 job, and some your jobs are damn dangerous. We lost a
2 good person just recently.
3 MR. HOOVER: We certainly did.
4 COM. HATCH-MILLER: And let me express my deep
5 sympathy for that.
6 You know, kind of to this point, do you feel or
7 are your men and women oversupervised or are there too
8 many people at the top?
9 MR. HOOVER: No. In the ranks of management
10 there has been consolidation. We consolidated our
11 departments, and we consolidated.
12 And when I talk about consolidation, basically
13 you are eliminating people and positions. So that
14 happened on the union front, and it also happened in
15 management side of the house.
16 COM. HATCH-MILLER: And at your level, do you see
17 a lot of excess equipment or money going out the door that
18 is not being used to get the task done.
19 MR. HOOVER: Absolutely not. Like Mr. Brandt
20 said, he had put a team together a while back, before this
21 financial mess that we are -- that this country and this
22 world is facing, to look at everything, to explore. And
23 this company is continuously looking at new ways to
24 explore, to be more efficient, more productive, safer, cut
25 costs. I mean, that is ingrained in us.

1 I have been with the company 29 years, and that
2 is basically the culture I have grown up in this company.
3 COM. HATCH-MILLER: Okay. So you are not seeing
4 a -- how do I put it the best way?
5 You are seeing -- you are seeing out there in the
6 real world of APS the effects of the cost-cutting
7 measures. You are seeing them actually out there?
8 MR. HOOVER: Absolutely. I'm a front-line
9 employee. I'm a journeymen lineman by trade. I work on
10 all the high voltage electricity. Absolutely.
11 COM. HATCH-MILLER: Okay. And assuming from what
12 you say that you don't have a lot of lax time. It's not
13 like a real kickback schedule you guys are all on. You
14 are not driving around all access and all that?
15 MR. HOOVER: No.
16 COM. HATCH-MILLER: You are working hard for your
17 money?
18 MR. HOOVER: Yes.
19 COM. HATCH-MILLER: And you feel they are as
20 well?
21 MR. HOOVER: Absolutely.
22 COM. HATCH-MILLER: Thank you.
23 CHMN. GLEASON: Commissioner Mundell.
24 COM. MUNDELL: Thank you, Mr. Chairman.
25 Thank you, Mr. Hoover, for being here.

1 You know, I talked about -- earlier about joint
2 sacrifice, and I appreciate the sacrifice that you and
3 your members are making. And I guess all I'm asking for
4 is, like I said, sacrifice not only from the workers but
5 from everyone in the company, and I guess we will continue
6 to discuss that the rest of day today and tomorrow.
7 So just to be clear about it, I have respect
8 also, you know, for the officers of the company. I think
9 Mr. Post is salt-of-the-earth guy.
10 I have been around here nine years now, but we as
11 regulators have a job to do. And you heard me jokingly
12 talk about that earlier when I was talking about the SEC
13 and how they're investigating themselves about how they
14 didn't do their job as regulators and everything we have
15 seen on Wall Street. There is a place for regulation in
16 our society. The question is: How do you balance it?
17 So just to be clear, I have respect for them,
18 too. I disagree with them at times. I try to do it in a
19 professional manner, but I think it's important to say
20 that.
21 Having said that, we still need to delve into the
22 issues, and it's too bad that all, you know, the unions
23 around the United States don't have the same outlook that
24 you do. It seems like you have a good working
25 relationship with the management, and you are trying to

1 reach a common goal. I mean, we saw what happened with
2 the big three back in Washington.
3 So I guess what I would say is, these are not
4 easy decisions. You heard me talking about the Chamber
5 this morning. I mean, RUCO is against this rate increase.
6 RUCO is appointed by the governor. So the governor of
7 Arizona is saying we should not -- through their
8 spokesperson, is saying we should not grant this rate
9 increase. And so then we have -- and they are saying
10 that, based on their evidence and the testimony, that it
11 won't lead to a downgrade.
12 So we have this conflicting evidence that we have
13 to sort out. And so, just again, the same kind of
14 discussion that I gave this morning with Chambers, please
15 be cognizant there are two sides to every issue, and there
16 are conflicting pieces of evidence and facts in front of
17 this Commission trying to make this difficult decision.
18 But again, I'm glad you are here, and I
19 appreciate you said it's interesting. I know -- I guess
20 it's like beauty in the eyes of a beholder; right?
21 MR. HOOVER: You learn something new every day.
22 COM. MUNDELL: You do, and I appreciate that. I
23 appreciate all the hard work you are doing.
24 Again, we will wait to hear from RUCO and why
25 they oppose the rate increase, and then we will have to

1 sort that out. But --

2 And if you have suggestions about any other cost

3 cutting that this Commission, you know, can look at to try

4 to, you know, prevent layoffs but also provide affordable

5 reliable service to the customers, I'm sure that we would

6 love to hear about it.

7 MR. HOOVER: And I appreciate your comments,

8 Commissioner.

9 And to your point, you know, we have got probably

10 one the most unique relationships in the utility industry

11 across this country, a labor union and a company. Usually

12 labor unions are viewed as very adversarial. There are

13 certain things that we don't agree with the Company, but

14 there are a lot of things that are to the success of this

15 company and our shareholders and our customers and

16 creating jobs for us. You know, so if Arizona Public

17 Service Company doesn't survive, we don't survive. So --

18 But we have got a very unique relationship that I

19 would put our relationship up against any relationship in

20 a utility industry across this country. We have got

21 officers of our local -- of our company that come down to

22 our executive board, give us an update. Other local

23 unions across the country, say, "The officers of the

24 company coming down there?"

25 I said, "Absolutely. They come down all the

1 time. We invite them. They keep us up to date on the
2 challenges that we and the company are facing together."
3 So we do have a very unique relationship, and
4 it's one that I would put up against any utility in this
5 country.
6 To expand a little bit on Commissioner Mayes'
7 comment on the benefit -- defined benefit, as Mr. Brandt
8 told you, in 2003, that was one of the things that, you
9 know, we obviously were looking at, you know, and always
10 looking at is cost.
11 And so in our 2003 agreement we had our defined
12 pension, and we were given the option to go to a cash
13 balance. But then also the Union at that point in time
14 gave up and made that any new hires after 2003 would fall
15 under that cash balance and not put such a burden -- a
16 financial burden on the Company for that defined pension.
17 So, you know, we put teams together to look at
18 this. So we understand this, and we understand that you
19 have a difficult task ahead of you. But I'm here to tell
20 you our relationship is very unique.
21 COM. MUNDELL: Well, it is, and it's too bad that
22 it can't spread throughout the country, as I said, because
23 we need cooperation and joint sacrifice if we are going to
24 keep our -- this utility viable but in our homegrown
25 industry.

1 So it's really -- I'm glad you showed up and
2 spoke because it's fascinating to hear your perspective.
3 Thank you very much.
4 CHMN. GLEASON: Thank you.
5 You made a statement earlier that if APS -- if
6 their bonds go to junk bond capacity that they will be
7 there a long time.
8 On what basis did you make that?
9 MR. HOOVER: Mr. Chairman, I base that off of
10 looking at the rest of the country and looking at -- I am
11 an investor also in the mutual funds and everything. And
12 I track a lot of companies and I watch the performance of
13 companies, and like Mr. Brandt said and probably everybody
14 in this room, you know, if you watched a portfolio drop
15 30, 40, 50 percent.
16 But I also watch companies, too, that fall into
17 junk status. And a lot of them have a very difficult time
18 climbing out of that cellar of junk bond status to get
19 their credit ratings back up. It's a very painful
20 process.
21 CHMN. GLEASON: Did you read the record of this
22 case?
23 MR. HOOVER: Some of it.
24 CHMN. GLEASON: Did you read the record on junk
25 bonds? There was an expert here that said that they don't

1 necessarily stay in that category very long?
2 MR. HOOVER: I have heard a lot about --
3 CHMN. GLEASON: Did you read the record? We go
4 by the record in this case.
5 MR. HOOVER: Not that portion.
6 CHMN. GLEASON: Okay. Thank you.
7 You said you have an aging workforce.
8 There has been some layoffs; right?
9 MR. HOOVER: We have had a reduction in force,
10 correct.
11 CHMN. GLEASON: Okay. Who was reduced, the older
12 workers or the younger ones?
13 MR. HOOVER: The older workers were given an
14 opportunity with a severance package. We also -- like I
15 said earlier, we consolidated departments. We did not
16 fill jobs.
17 Based off Commissioner Mayes' remarks or
18 Commissioner Mundell's, you don't want to have a layoff.
19 The layoff, if we end up having a layoff in a union, it
20 affects the least-senior people in the company. That is
21 your future work force, you know.
22 So it doesn't make sense to go into a layoff and
23 affect your future work force that has those scars for the
24 rest of their lives about being laid off. If you can come
25 to a mutual agreement and understanding, a more proactive

1 way to allow people to leave the company, consolidate
2 departments and reduce jobs that way, it works out a whole
3 heck of a lot better for the union side of the house. And
4 that is what we collectively did with the company.
5 CHMN. GLEASON: Okay. Then, but the union has a
6 real bias to, for the rate increase; in other words, you
7 feel it will benefit the union?
8 MR. HOOVER: Absolutely.
9 CHMN. GLEASON: Okay. Thank you.
10 Mr. Pierce.
11 COM. PIERCE: Thank you. I would like to address
12 that bias just for a moment.
13 Unions ought to care about a company's
14 competitiveness, and I think that is part of the problem
15 with some of our friends in the Midwest, is that companies
16 are not competitive. They are losing money, and the
17 unions seem to be disconnected from that.
18 But in the regulated utility, such as APS, don't
19 you believe that the ability of the customers to pay,
20 their ability to pay, needs to be also a concern of the
21 union?
22 MR. HOOVER: Absolutely, that their ability to
23 pay their bills needs to be addressed.
24 You know, I'm out there every day. I hear. I
25 interact with our customers on a daily basis. You know, I

1 hear and I pay APS rates, just like probably a lot of
2 people in this room. And I interact with our public.
3 The public tells me, well, you know, APS, I pay
4 high utility rates in the summertime. Well, out here in
5 the southwest, you know, everybody pays high rates. You
6 go back east during the wintertime, you will pay high
7 rates back there.
8 So, you know, that is a concern. You know, but I
9 can honestly tell you through providing safe reliable
10 power to our customers, you don't -- like I say, I'm out
11 there. I don't get the negative feedback back from the
12 customers that are saying, you know, that their rates are
13 too high and all the grumblings and everything because we
14 are providing a safe reliable commodity to our customers.
15 COM. PIERCE: The relationship that employees
16 have with APS, that relationship, I think, on the whole is
17 unique. Because I think there are a lot of employees that
18 have been around as long as Mr. Post, and I mean, a lot of
19 them.
20 The rural communities that greater Arizona has, I
21 think local people have a closer connection to the people
22 that are employed by APS and know who they are; whereas in
23 Phoenix, that -- it's -- a lot of people may not know
24 anyone that works for APS. But many of the folks I knew,
25 I think, still work there -- I think some of them have

1 sons that now work for APS as well -- and have been there
2 longer than you have.
3 And so when there is discussion about longevity
4 and trying to, and you looked at early retirement, a lot
5 of folks have been in these positions a long, long time.
6 MR. HOOVER: Absolutely.
7 COM. PIERCE: Have you pretty much been in this
8 market here with APS in your tenure?
9 MR. HOOVER: Yes. I have been with the company
10 29 years. I started out in the mailroom delivering mail,
11 got into the garage and then got on out on the line crew
12 and I was a groundman. And then I ended up bidding an
13 apprenticeship. And then I served my apprenticeship and I
14 have been a journeymen lineman and a crew foreman for the
15 last 26 years with the company.
16 COM. PIERCE: And, I think, that's -- see that is
17 very commendable for the company. I think their ability
18 to retain valuable employees, but it also says something
19 for the regulatory environment that allows good-paying
20 jobs to continue.
21 And so it's a balancing act because all of this
22 is on the back of the ratepayers, as you well know. So
23 it's kind of a -- you know, you look at that link, that
24 unique relationship between the Company and the employees.
25 I think the next part of that is the ratepayers, that it's

1 really a three-legged stool. We are not really part of
2 that. You know, we are if we are the APS ratepayer, we
3 are part of that customer side of it.
4 And so it's one of those things that we have to
5 balance, appreciating everything you said and the value of
6 everything that you have said, I understand and have for a
7 long, long time, and I am appreciative of that, but I
8 balance that as I think about the effect on ratepayers.
9 But thank you for being here. It's great to hear
10 from you.
11 MR. HOOVER: My pleasure. Just a little comment
12 off that.
13 You know, I have -- my dad -- Bill Post worked
14 for my dad at Arizona Public Service Company, and I have
15 watched Bill Post grow up to where he is at today, too.
16 And my son now is working for Arizona Public Service
17 Company.
18 So you talk about the longevity, you know,
19 throughout the utility industry, APS has made a name for
20 itself out here, and there are people all across the
21 country that want to come out here and come to work for
22 Arizona Public Service Company because of Bill Post, the
23 officers' leadership and because of our unique
24 relationship. And that has to say something pretty
25 important about Arizona Public Service Company.

1 And the longevity of our employees, too, is
2 another asset to this company.
3 MR. PIERCE: Well, maybe they want to work out
4 here for less. I know Mr. Brandt was saying --
5 Commissioner Mundell went up there on the board. I think
6 he is going right to that point. I will back off and let
7 him go.
8 CHMN. GLEASON: Mundell.
9 COM. MUNDELL: I don't want to pick on
10 Mr. Hoover.
11 I was just going to say, Mr. Brandt, he made my
12 point, that people want to come to Arizona, you know, for
13 other than just purely dollars.
14 So thank you, Mr. Hoover. He will probably
15 listen to you more than he will listen to me.
16 MR. HOOVER: Let me expand a little bit on that.
17 COM. MUNDELL: Mr. Hoover, there is question in
18 front of you.
19 CHMN. GLEASON: We have got your point.
20 MR. HOOVER: Let me expand on my comment.
21 You know, I'm a journeymen linemen. You know,
22 and journeymen linemen want to come here for this unique
23 relationship. And I can tell you what, you know, if APS
24 isn't paying a competitive wage and benefit package to
25 your journeymen linemen, which is a highly-skilled worker,

1 guess where they are going. They are going right over
2 there to California where they are going to be paying
3 probably $50 an hour, double time and everything else,
4 something we don't have here at Arizona Public Service
5 Company.
6 So that is the mentality of a journeymen linemen.
7 They are going where the money is at or wherever they have
8 got some good sound job security.
9 COM. MUNDELL: I can see why you are president.
10 Thank you.
11 CHMN. GLEASON: Okay. Mr. Hatch-Miller.
12 COM. HATCH-MILLER: And that was the point we
13 have been discussing, as you know. I think it's an
14 important one.
15 Because as I try to see about moving people from
16 one point to another, what I'm finding is it's not as easy
17 to move a family as it was just two or three years ago.
18 They cannot sell their house. If they do sell their
19 house, they might sell it at a loss or looking at a new
20 job. Am I going to take a loss here if I can sell the
21 house? Where am I going to live when I get there?
22 It's become a much more complex picture. I don't
23 want to oversimplify it and just think that, well, people
24 want to come here. It's not that easy.
25 MR. HOOVER: Yes.

1 CHMN. GLEASON: Okay. Thank you very much.
2 MR. HOOVER: Thank you.
3 CHMN. GLEASON: Okay. I guess AIC.
4 I assume you are looking at the clock.
5 MR. GRANT: I will be quick.
6 COM. MUNDELL: Mr. Grant was here late yesterday
7 too.
8 MR. GRANT: Mr. Chairman, Commissioners, good
9 afternoon. Again, Mike Grant, Gallagher & Kennedy on
10 behalf of the Arizona Investment Council.
11 I wish Mr. Robertson could go next because that
12 is kind of a tough act to follow. And the other problem I
13 have got is I have restructured these darn opening
14 comments about nine times today as I have listened to what
15 is going on at the bench. So let me try to this way, and
16 we have heard this a lot today.
17 These are extraordinary and unprecedented times.
18 I think investors -- debt and equity, current and
19 prospective -- see these things standing out in an
20 especially dangerous mix of capital and credit markets
21 that are injured and unfortunately, so far, growing weaker
22 despite Herculean trillion-dollar efforts to revive them,
23 a company, which despite recent significant CAPX cuts,
24 needs about $2 billion of access to those capital markets
25 over the next five years.

1 STATE OF ARIZONA.)
) ss.
2 COUNTY OF MARICOPA)
3
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6
7 I, KATE E. BAUMGARTH, RPR, Certified Reporter
8 No. 50582, for the State of Arizona, do hereby certify
9 that the foregoing printed pages constitute a full, and
10 accurate transcript of the proceedings had in the
11 foregoing matter, all done to the best of my skill and
12 ability.
13
14 WITNESS my hand this 22nd day of
15 December, 2009.
16
17
18
19
20
21 Kate E. Baumgarth, RPR
Certified Reporter, No. 50582
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23
24
25

EXHIBIT
IBEW-3
ADMITTED

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2009 JUN 30 P 4: 14
AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA

CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-08-0172 **NOTICE OF FILING DIRECT TESTIMONY OF SAMUEL ELLIOTT HOOVER II**

Pursuant to the Chief Administrative Law Judge's Procedural Order (p. 2) dated May 11, 2009, Intervenors Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"), Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640"), and Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769"), by and through undersigned counsel, hereby provide notice of its filing of the attached Direct Testimony of Samuel Elliott Hoover II in this docket.

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RESPECTFULLY SUBMITTED this 30th day of June 2009.

LUBIN & ENOCH, P.C.

Janett J. Hashore (for NE)

Nicholas J. Enoch, Esq.
Attorney for Interveners
IBEW Locals 387, 640 & 769

Original and thirteen (13) copies of Interveners' Notice filed this 30th day of June, 2009, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing transmitted electronically or via regular mail this same date to:

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F:\Michael\IBEW1445-074.NoF#3.pld.wpd

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Samuel Elliott Hoover II. My business address is 5818 North 7th Street, Suite 201, Phoenix, Arizona 85014.

Q2. ARE YOU THE SAME SAMUEL ELLIOTT HOOVER II WHOSE DIRECT TESTIMONY WAS FILED IN THIS MATTER ON DECEMBER 19, 2008?

A2. Yes.

Q3. DO YOU HAVE ANY REVISIONS THAT YOU WOULD LIKE TO MAKE TO YOUR PREVIOUS TESTIMONY?

A3. The word "hate" on page 5, line 16 of my testimony should, instead, read "rate."

Q4. DID YOU ALSO TESTIFY BEFORE THE COMMISSION ON DECEMBER 17, 2008?

A4. Yes. On December 17, 2008, I addressed and answered questions from this Commission regarding Arizona Public Service Company's ("APS") request for interim rate relief and the IBEW Locals' support thereof. A copy of the transcript of my previous testimony was filed with the Commission on December 30, 2008.[1]

Q5. DO INTERVENORS LOCAL UNION 387, 640 AND 769, INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS, AFL-CIO, CLC (herein "IBEW Local 387," "IBEW Local 640," and "IBEW Local 769") SUPPORT THE ADOPTION OF THE JUNE 12, 2009 SETTLEMENT AGREEMENT?

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[1] *See* View Image No. 0000093009.

A5. Yes. On behalf of the more than two-thousand one-hundred (2,100) non-managerial workers at APS who are represented by IBEW Local 387, I would like to express the Union's unqualified support for the proposed Settlement Agreement. In addition, I know that our two sister locals, IBEW Locals 640 and 769, are also fully supportive of the Settlement Agreement as their members, who also number in the hundreds, and their associated contractors are likely to benefit greatly from the various large-scale construction projects contemplated in the Agreement.

Q6. ARE THERE SPECIFIC PORTIONS OF THE SETTLEMENT AGREEMENT THAT IBEW LOCALS 387, 640 AND 769 ARE PARTICULARLY INTERESTED IN?

A6. Yes. While IBEW Locals 387, 640 and 769 support the adoption of proposed Settlement Agreement in its entirety, we took a particularly active role in negotiating and/or otherwise considering the following specific paragraphs of the proposed Settlement Agreement: ¶¶1.15, 7.4 and 13.4(a)(vi).

Q7. PLEASE EXPLAIN WHY IBEW LOCAL 387 IS PARTICULARLY INTERESTED IN ¶1.15.

A7. Paragraph 1.15 was derived, in relevant part, from ¶1.14(ii) of the most recent settlement agreement involving the Tucson Electric Power Company ("TEP"). In it, the parties simply acknowledge the fact that Article XV, §3 of the Arizona Constitution places the interests of public service employees on par with those

of patrons. The interests of both constituencies, in turn, are of more importance than those of the corporation's shareholders.

Q8. ARE YOU AWARE OF ANY LEGAL AUTHORITY SUPPORTING THIS PROPOSITION?

A8. Certainly. In its 1984 decision in *Cogent Pub. Serv. v. Arizona Corp. Comm'n*, 142 Ariz. 52, 56-57, 688 P.2d 698, 702-03, Division One expressly, and in my opinion, correctly, held that "the jurisprudence of our State made it plain long ago that the interests of public-service corporation stockholders must not be permitted to overshadow those of the public served." In support of this quite unremarkable proposition, our Court of Appeals relied upon a series of U.S. and Arizona Supreme Court decisions dating back to 1896.[2] Beyond that, I would also point out that while Article XV, §3 of the Arizona Constitution mentions "employees and patrons" as key stakeholders, it does not mention shareholders as such.

Q9. PLEASE EXPLAIN WHY IBEW LOCALS 387, 640 AND 769 ARE PARTICULARLY INTERESTED IN ¶7.4.

A9. It goes without saying that no one, including the employees, contractors and patrons of APS, benefits from any cost savings which comes at the expense of providing safe and reliable electric service. This

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[2] *See Salt River Valley Canal Co. v. Nelssen*, 10 Ariz. 9, 13, 85 P. 117, 119 (1906) [*citing Covington & Lexington Turnpike Road Co. v. Sanford*, 164 U.S. 578, 596 (1896)].

paragraph clearly serves the greater public interest.

Q10. PLEASE EXPLAIN WHY IBEW LOCAL 387 IS PARTICULARLY INTERESTED IN ¶13.4(a)(vi).

A10. In recent years, much has been written and said about Arizona becoming the so-called Persian Gulf of green energy or, in the words of APS, "the solar energy capital of the world" and how this transformation will, in turn, inevitably lead to an abundance of highly skilled, high-paying "green collar" jobs in the "new economy." While much has been done by Arizona policy makers, most prominently by this Commission, and our large public service corporations, including APS, to move the ball forward with respect to renewable energy development, I believe that we members of the Arizona labor movement, in the first instance, and Arizona policy makers, in the second instance, need to make sure that we are affirmatively moving the ball forward *vis-á-vis* the development of the often referenced highly skilled, highly paid "green collar" jobs of the so-called the new economy. While I tend to think that there is little doubt that Arizona will, within the next twenty-five (25) to fifty (50) years, become a - if not "the" - world leader when it comes to the generation and, hopefully, out-of-state transmission of green energy, I do not believe that this will, in and of itself, mean that the

workers of our State will dramatically benefit from this new industry. It is for this reason that in conjunction with the measuring of APS's performance, we would like the Commission to monitor APS's headcount formally moving forward. I am confident that the last thing that any of us would want is for Arizona to become the maquiladora of green energy. We, including this Commission and APS, need to be vigilant in the years to come to make certain that does not happen.

Q11. WHICH PORTIONS OF THE SETTLEMENT AGREEMENT IS IBEW LOCAL 640 MOST INTERESTED IN?

A11. While I am not a member of IBEW Local 640, I know for a fact that, as northern Arizona's inside construction local, IBEW Local 640 and its associated contractors are uniquely positioned to benefit from the proposed renewable construction projects set forth in ¶¶1.16(a), 13.2(a), 15.1, 15.2, 15.3, 15.5, and 15.6. In conjunction with the Phoenix Electrical Joint Apprenticeship and Training Committee for the Electrical Industry ("JATC"), IBEW Local 640 is at the forefront of recruiting and training electricians specifically in the area of solar installation and maintenance. A copy of the syllabus for the new JATC solar program is attached hereto as Exhibit A. As such, I would hope and expect that the membership of

IBEW Local 640 will have the inside track when it comes time to build all of these renewable resources.

Q12. WHICH PORTIONS OF THE SETTLEMENT AGREEMENT IS IBEW LOCAL 769 MOST INTERESTED IN?

A12. IBEW Local 769, as the exclusive bargaining agent for all IBEW outside line workers in the State of Arizona, is also uniquely positioned to benefit from the proposed transmission and construction projects set forth in ¶¶1.16(a), 15.2, and 15.4. For example, IBEW Local 769, along with IBEW Local 640, are at the forefront of the fledgling in-state wind generation business here in the State of Arizona. In this connection, attached hereto as Exhibit B is a copy of the form IBEW International Wind Turbine Agreement which, hopefully, will become the template under which all of the construction work addressed in ¶15.2 will take place.

Q13. ARE THERE ANY PORTIONS OF THE PROPOSED SETTLEMENT AGREEMENT WITH WHICH IBEW LOCALS 387, 640 AND 769 ARE LESS PLEASED?

A13. Sure. As explained in ¶1.10 of the Settlement Agreement, we would have preferred that APS receive even more - potentially far more - rate relief than what is set forth herein. Notwithstanding these reservations, however, IBEW Local 387, 640 and 769 recognize that the

consummation of a comprehensive Settlement Agreement amongst nearly two dozen different parties with often disparate and competing interests is no so small feat. It is for that reason that we fully and strongly support the Commission's adoption of the proposed Settlement Agreement *in toto*.

Q14. IN HER JUNE 9, 2009 LETTER TO THE PARTIES TO THE DOCKET, CHAIRMAN KRISTIN K. MAYES POSES A NUMBER OF POINTED QUESTIONS TO THE SETTLING PARTIES. ARE YOU PREPARED TO ANSWER CHAIRMAN MAYES' QUESTIONS ON BEHALF OF IBEW LOCALS 387, 640 AND 769?

A14. Certainly. Before doing so, however, I would like to point out that a number of the questions posed by Chairman Mayes pertain to topics and issues of only marginal concern to IBEW Locals 387, 640 and 769. In those instances, I believe that APS's letter to the docket dated June 25, 2009 provides a fair overview of the positions held by IBEW Locals 387, 640 and 769. Thus, I have limited my testimony to only those issues and topics of which the three IBEW locals are truly concerned and informed.

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Q15. FAIR ENOUGH. ON PAGE ONE (1) OF HER LETTER, CHAIRMAN MAYES ASKS IF "THE STAY OUT PROVISION ... CAN FAIRLY BE CONSIDERED AS A TRUE BENEFIT TO CONSUMERS" AND SHE WANTS TO KNOW "WHAT WEIGHT IT WAS GIVEN BY THE SETTLING PARTIES IN ARRIVING AT THE PROPOSED AGREEMENT[.]" WHAT IS YOUR RESPONSE TO HER QUESTIONS?

A15. Mr. Hatfield's commentary notwithstanding, I do not know when APS would have planned on coming back with another general rate case and, as such, I believe the so-called "Stay Out" provision does provide consumers a certain amount of clarity and gradualism moving forward. This particular topic was not of major concern to the three IBEW locals in arriving at the proposed Agreement.

Q16. ON PAGES ONE (1) TO TWO (2) OF HER LETTER, CHAIRMAN MAYES INQUIRES "WHETHER THE COMMISSION COULD ACHIEVE THE 12 MONTH TIME CLOCK PROVISION CALLED FOR IN THE TERM SHEET IF THE LEGISLATURE'S CUTS ARE ENACTED." WHAT IS YOUR RESPONSE TO THIS QUESTION?

A16. I share Chairman Mayes' concern about the state of the Commission's budget moving forward. I believe that her well-founded practical concerns were implicitly addressed by the "good faith efforts" language set forth in ¶2.3 of the Settlement Agreement.

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Q17. ON PAGES TWO (2) TO THREE (3) OF HER LETTER, CHAIRMAN MAYES INQUIRES ABOUT THE TIME FRAME AND PROCESS FOR SELECTING THE PROPOSED WIND PROJECT AND WHETHER THE SETTLEMENT AGREEMENT WOULD REQUIRE THE WIND PROJECT TO BE IN ARIZONA. DO YOU BELIEVE THAT ¶15.2 OF THE SETTLEMENT AGREEMENT ADEQUATELY RESPONDS TO CHAIRMAN MAYES' QUESTIONS?

A17. Essentially, "yes." You can be assured, however, that all three IBEW Locals will be watching this particular topic very closely in the weeks and months to come. We each have a keen and vested interest in making certain that any in-state wind generation is built, maintained and operated by IBEW members.

Q18. ON PAGE THREE (3) OF HER LETTER, CHAIRMAN MAYES ASKS "WHETHER THE PARTIES WOULD OBJECT TO THE COMMISSION REQUIRING APS TO EXCEED THE RES ['RENEWABLE ENERGY STANDARD']" IN THE CONTEXT OF THE INSTANT RATE CASE. WHAT IS YOUR RESPONSE TO THIS QUESTION?

A18. Whether such a move on the part of the Commission is justified by the record in this case or not, or whether it is sound public policy or not, I am reasonably confident that this Settlement Agreement would not have been possible had the parties chosen to tackle this extremely complex, important and, indeed, thorny topic in the context of the instant rate case. While I am not certain,

I would guess that the inclusion of any such provision in the final order in this case will, almost inevitably, lead to one or more of the Settling Parties opting out of the settlement in accordance with ¶23.5 of the Settlement Agreement. That being the case, IBEW Locals 387, 640 and 769 respectfully submit that this particular topic is best left for another case, perhaps for a generic docket, in which all interested parties, including other public service corporations (such as TEP) and their respective labor unions, could voice their positions. Given the tremendous up-front expense associated with the development of renewable generation and transmission, I believe that is by far the better procedural method by which this issue ought to be handled.

Procedural concerns notwithstanding, I can tell you that IBEW Locals 387, 640 and 769 have absolutely no problem with the idea of increasing the RES at some point in the future provided that, *inter alia*, it is economically feasible for APS to do so and the envisioned renewable generation is built, maintained and operated by members of the IBEW in the State of Arizona.

Q19. DO YOU HAVE ANY OTHER COMMENTS YOU WOULD LIKE TO SHARE WITH THE COMMISSION REGARDING THE INSTANT SETTLEMENT?

A19. Yes. I want to make it abundantly clear to the Commission and APS that, by agreeing to this Settlement Agreement, IBEW Local 387 has not, and does not, agree to any modification, express or implied, to the terms and conditions of its collective bargaining agreement with APS. That is not to say that I believe this will ever become a problem *vis-á-vis* IBEW Local 387's relationship with APS; in fact, I do not believe that is the case. Nevertheless, I just want to make certain that there is no confusion in this regard moving forward.

Q20. DOES THIS CONCLUDE YOUR TESTIMONY?

A20. Yes.

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EXHIBIT A

Photovoltaic Systems

All materials are copyrighted by the National Joint Apprenticeship and Training Committee.
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Lesson	Title	Page	Reference 1	Reference 2	Reference 3
1	Introduction to Photovoltaic Systems	1	*Photovoltaic Systems* Textbook		
2	Fundamentals of Solar Radiation	7	*Photovoltaic Systems* Textbook		
3	Sun-Earth Relationships	13	*Photovoltaic Systems* Textbook		
4	Solar Radiation Data and Measurements	19	*Photovoltaic Systems* Textbook		
5	Site Surveys and Planning	25	*Photovoltaic Systems* Textbook	*OSHA Standards for the Construction Industry*	
6	Photovoltaic Systems and Components	31	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
7	Fundamentals of Photovoltaic Devices	35	*Photovoltaic Systems* Textbook		
8	Photovoltaic Modules and Arrays	41	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
9	Batteries	51	*Photovoltaic Systems* Textbook	*National Electrical Code®*	*OSHA Standards for the Construction Industry*
10	Charge Controllers	59	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
11	Inverters	67	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
12	System Sizing	75	*Photovoltaic Systems* Textbook		
13	Mechanical Integration	85	*Photovoltaic Systems* Textbook		
14	Electrical Integration I	93	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
15	Electrical Integration II	101	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
16	Utility Interconnection	107	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
17	Permitting and Inspection	115	*Photovoltaic Systems* Textbook	*National Electrical Code®*	
18	Operations and Maintenance	121	*Photovoltaic Systems* Textbook	*National Electrical Code®*	*OSHA Standards for the Construction Industry*
19	Economic Analysis	129	*Photovoltaic Systems* Textbook		

EXHIBIT B

IBEW INTERNATIONAL WIND TURBINE AGREEMENT

ARTICLE I

Section 1.01. This Agreement made and entered into by and between _____ and the INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS is applicable to and shall be utilized by _____ for all its work within the scope of this Agreement throughout the United States.

Section 1.02. The term "Employer" or "Company," as hereinafter used, shall mean _____.

Section 1.03. The term "IBEW" or "Union," as hereinafter used, shall mean the International Brotherhood of Electrical Workers.

Section 1.04. The term "Local Union," as hereinafter used, shall mean an IBEW Local Union.

Section 1.05. The term "Employee" or "Worker," as hereinafter used, shall mean the worker or workers listed and classified in Article XI of this Agreement.

ARTICLE II

Scope of Agreement

Section 2.01. This Agreement covers all work involved in the construction, erection, maintenance, repair and service of wind turbines, including all electrical work within the confines of the wind turbine itself, up to the secondary side of the transformer at the base of the wind turbine, including the setting of the generator. All electrical work from the transformer (base located transformers), including the installation of the transformer itself, to and including the substation, setting of the wind turbine tower and all work related to the construction of the base is also

covered by this Agreement when performed by employees covered by this Agreement in the United States by the Employer or by any person, firm or corporation owned or controlled by the Employer. This Agreement shall be granted on a project-by-project basis and shall have application only to the project agreed upon between the IBEW and the Employer.

ARTICLE III

Duration and Special Provisions

Section 3.01 (a). This Agreement shall take effect for any jobs bid after _____ and remain in effect through _____ unless otherwise specifically provided for herein. It shall continue in effect from year to year thereafter, from January through December of each year, unless changed or terminated in the manner later provided herein.

(b). Either party desiring to terminate this Agreement must notify the other, in writing, at least ninety (90) days prior to the anniversary date.

(c). This Agreement shall be subject to change or supplement at any time by mutual consent of the parties hereto. Any such change or supplement agreed upon shall be reduced to writing, and signed by the parties hereto.

ARTICLE IV

Grievances and Disputes

Section 4.01. During the term of this Agreement, there shall be no stoppage of work either by strike or lockout because of any proposed changes in this Agreement or dispute over matters relating to this Agreement. All such matters must be handled as stated herein.

Section 4.02. All grievances shall be filed within ten (10) calendar days after the complained-of event arose. Grievances shall be appealed to the next higher step within ten (10) calendar days after the meeting in the lower step. Settlement of grievances may be arrived at in any step of the grievance procedure, which will be final and binding on the Union and Employer.

Grievances, other than those pertaining to jurisdiction or general wages, on any work covered by this Agreement, shall be handed in the following manner:

Step 1. Between the Employer's Supervisor and the Local Union Representative at the job site.

Step 2. Between the Business Representative and the Employer's Supervisor at the job site.

Step 3. Between the International Union Representative and the Supervisor or Labor Relations Manager.

Step 4. If the parties are unable to effect an amicable settlement or adjustment of any grievance or controversy, it shall be submitted to the Council of Industrial Relations for the Electrical Contracting Industry for adjudication. The Council's decision shall be final and binding.

Section 4.03. When any matter in dispute has been referred to the Council for adjustment, the provisions and conditions prevailing prior to the time such matters arose shall not be changed or abrogated until agreement has been reached or a ruling has been made.

Section 4.04. Each party shall bear the expense of preparing and presenting its own case.

ARTICLE V

Subcontracting – Work Preservation

Section 5.01. Local Unions are a part of the IBEW and any violation or annulment by the Employer of this Agreement or an approved Agreement of any Local Union of the IBEW, other than violations of Paragraph 2 of this Section, will be sufficient cause for cancellation of this Agreement by the Union after a finding has been made that such a violation or annulment has occurred.

The subletting, assigning or transfer by the Employer of any work in connection with electrical work to any person, firm or corporation not recognizing the IBEW or one of its Local Unions as the collective bargaining representative of his employees on any electrical work in the trade jurisdiction of the Union to be performed at the site where construction, alteration, painting or repair of a building, structure or other work is ongoing, will be deemed a material breach of this Agreement.

All charges of violations of this Section shall be considered as a dispute and shall be processed in accordance with the provisions of this Agreement covering the procedures for the handling of grievances and the final and binding resolution of disputes.

Section 5.02(a). In order to protect and preserve, for the employees covered by this Agreement, all work heretofore performed by them, and in order to prevent any device or subterfuge to avoid the protection and preservation of such work, it is hereby agreed as follows: If and when the Employer shall perform any on-site construction work of the type covered by this Agreement, under its own name or under the name of another, as a Corporation, Company, Partnership, or any other business entity, including joint venture, wherein the Employer, through its officers, directors, partners or stockholders, exercises either directly or indirectly, management, control or majority ownership, the terms and conditions of this Agreement shall be applicable to all such work. All charges of violations of this Section shall

be considered as a dispute and shall be processed in accordance with the provisions of this Agreement covering the procedure for the handling of grievances and the final and binding resolution of disputes.

(b). As a remedy for violations of this Section, the Labor-Management Committee, the Council on Industrial Relations for the Electrical Contracting Industry and/or an independent arbitrator, as the case may be, are empowered, in their discretion and at the request of the Union, to require an Employer to (1) pay to affected employees covered by this Agreement, including registered applicants for employment, the equivalent of wages lost by such employees as a result of the violations; and (2) pay into affected joint trust funds established under this Agreement any delinquent contributions to such funds which have resulted from violations. Provision for this remedy herein does not make such remedy the exclusive remedy available to the Union for violation of this Section; nor does it make the same or other remedies unavailable to the Union for violations of other Sections or other Articles of this Agreement.

(c). If, as a result of violations of this Section, it is necessary for the Union and/or the trustees of the joint trust funds to institute court action to enforce an award rendered in accordance with subsection (b) above, or to defend an action which seeks to vacate such award, the Employer shall pay any accountants' and attorneys' fees incurred by the Union and/or fund trustees, plus costs of the litigation, which have resulted from the bringing of such court action.

ARTICLE VI

National Electrical Benefit Fund

Section 6.01. It is agreed that, in accord with the Employees Benefit Agreement of the National Electrical Benefit Fund ("NEBF"), as entered into between the National Electrical Contractors Association and the International Brotherhood of Electrical Workers on September 3, 1946, as amended, and now delineated as the Restated Employees Benefit

Agreement and Trust, unless authorized otherwise by the NEBF, the individual Employer will forward monthly to the NEBF's designated local collection agent an amount equal to 3% of the gross monthly labor payroll paid to, or accrued by, the employees in this bargaining unit, and a completed payroll report prescribed by the NEBF. The payment shall be made by check or draft and shall constitute a debt due and owing to the NEBF on the last day of each calendar month, which may be recovered by suit initiated by the NEBF or its assignee. The payment and the payroll report shall be mailed to reach the office of the appropriate local collection agent not later than fifteen (15) calendar days following the end of each calendar month.

The individual Employer hereby accepts, and agrees to be bound by, the Restated Employees Benefit Agreement and Trust.

An individual Employer who fails to remit as provided above shall be additionally subject to having his Agreement terminated upon seventy-two (72) hours' notice, in writing, being served by the Union, provided the individual Employer fails to show satisfactory proof that the required payments have been paid to the appropriate local collection agent.

The failure of an individual Employer to comply with the applicable provisions of the Restated Employees Benefit Agreement and Trust shall also constitute a breach of his labor Agreement.

ARTICLE VII

Referral Procedure

Section 7.01. In the interest of maintaining an efficient system of production in the Industry, providing for an orderly procedure of referral of applicants for employment, preserving the legitimate interests of employees in their employment status within the area and of eliminating discrimination in employment because of membership or non-membership in the Union,

the parties hereto agree to the following system of referral of applicants for employment.

Section 7.02. The Employer shall be allowed to use and to send employees into the jurisdiction of any Local Union(s) on any job or project where work is being performed under this Agreement under the following schedule:

For each job or project, the Employer may use any employee referred by a Local Union(s) Collective Bargaining Referral Procedure and employed by the Employer on the date of the Pre-Bid Conference. Employees who have been referred from a Local Union Referral and are subsequently transferred to a job or project covered under this Agreement shall be allowed to return to that jurisdiction with the Employer. Employees who have been referred from a Local Union Collective Bargaining Referral Procedure can be transferred by the Employer to any job or project covered by this Agreement. When any complaint or dispute arises dealing with this question, any ruling made by the International President of the Union shall be accepted and put into effect.

Section 7.03. The Employer shall have the right to call foremen by name for projects covered by this Agreement provided:

(1) The employee has not quit his previous employer within the past two weeks.

(2) The Employer shall notify the Business Manager, in writing, of the name of the individual who is to be requested for employment as a foreman. Upon such request, the Business Manager shall refer said foreman provided the name appears on the highest priority group.

(3) When an employee is called as a foreman, he must remain as a foreman for 1,000 hours, or he must receive a reduction in force.

Section 7.04(a). In order to fill needs for additional workers, the Employer shall request the number and classifications of the workers required from the Local Union Referral in whose jurisdiction the work is located.

(b). The Local Union having jurisdiction where the work is being performed shall have the right to refer one applicant to each project within the jurisdiction of the Local Union.

Section 7.05. The Local Union(s) shall be the sole and exclusive source of referral of applicants for employment.

Section 7.06. The Employer shall have the right to reject any applicant for employment. The reason for rejection shall be provided to the Union in writing.

Section 7.07. The Local Union(s) shall select and refer applicants for employment without discrimination against such applicants by reason of membership or non-membership in the Union, and such selection and referral shall not be affected in any way by rules, regulations, bylaws, constitutional provisions or any other aspect or obligation of Union membership policies or requirements. All such selection and referral shall be in accord with the following procedure.

Section 7.08. The Local Union(s) shall maintain a register of applicants for employment. Each applicant for employment shall be registered in the highest priority group in the classification or classifications for which the applicant qualifies.

Section 7.09. If the registration list in a given classification is exhausted, and the Local Union is unable to refer applicants for employment to the Employer within 48 hours from the time of receiving the Employer's request, Saturdays, Sundays and Holidays excepted, the Employer shall be free to secure applicants without using the Referral Procedure.

Section 7.10. Any employees transferred or employed for any job or project in accordance with this Agreement will not be displaced by a Local Union under any Referral Procedure of that Local Union.

Section 7.11. In all cases, the Employer shall notify the Inside/Outside IBEW Local Union(s) having jurisdiction where the work is to be performed of the names and Social Security Numbers of all employees before starting work.

Section 7.12. The current approved Inside Training Agreement and/or Outside Area Training Agreement between the various IBEW Local Unions shall govern all matters of apprenticeship and training and the financing thereof. Apprentices' wages and the ratio of Apprentices to Journeymen are specified in the Area Training Agreements in the area where the work is being performed.

Section 7.13. Apprentices shall be hired and transferred in accordance with the Apprenticeship provisions of the Inside/Outside Area Training Agreements.

Section 7.14 The Employer shall make every effort to assign the work as follows; however, the Employer may assign work contrary to this breakdown of jurisdiction for up to fourteen (14) days in an effort to avoid short-term crew layoffs.

(A). Wind Turbines

Inside: All electrical work within the confines of the wind turbine itself up to the secondary side of the transformer at the base of the wind turbine, including the setting of the generator. In designs where the transformer is mounted within the confines of the wind turbine (i.e., mounted internally at the top of the structure), the Inside will have jurisdiction to the first connect location outside the confines of the wind turbine (splice point, top location, etc.).

Outside: All electrical work from the transformer (base located transformers), including the installation of the transformer itself, to and including the substation. When the wind turbine is designed with the transformer mounted within the structure (mounted at the top of the wind turbine), the Outside will have jurisdiction from the first connect location outside the confines of the wind turbine, to and including the substation. The Outside will set the wind turbine tower and do all work related to the construction of the base.

(B). The Employer understands that the Local Union's jurisdiction -- both trade and territorial -- is not a subject for negotiations but rather is determined solely within the IBEW by the International President and, therefore, agrees to recognize and be bound by such determinations.

ARTICLE VIII

Membership Provision

Section 8.01. All employees covered by the terms of this Agreement shall be required to become and remain members of the Union as a condition of employment from and after the eighth day following the date of their employment, or the effective date of this Agreement, whichever is later.

Section 8.02. The provisions of Section 8.01 shall be inoperative in any state in which such provision is contrary to State Law.

Section 8.03. The Employer shall deduct and forward to the Financial Secretary of the Local Union(s) where the work is being performed, upon receipt of a voluntary written authorization, working dues from the pay of each IBEW member. The amount to be deducted shall be the amount specified in the approved Local Union Bylaws of the Local Union in whose jurisdiction the work is to be performed. Such amount shall be certified to the Employer by the Local Union upon request by the Employer.

ARTICLE IX

Employer Rights

Section 9.01. The Union understands the Employer is responsible to perform the work required by the Owner. The Employer shall, therefore, have no restrictions, except those specifically provided for in this Agreement, in planning, directing and controlling the operation of all his work, in deciding the number and kind of employees to properly perform the work, in hiring and laying off employees, in transferring employees from job to job, in determining the need and number as well as the person who will act as foreman, in requiring all employees to observe the Employer's and/or Owner's rules and regulations not inconsistent with this Agreement, in requiring all employees to observe all safety regulations, and in discharging employees for proper cause.

ARTICLE X

Hours and Working Conditions

Section 10.01. Eight (8) hours' work between the hours of 6:00 a.m. and 6:00 p.m., with thirty (30) minutes for an unpaid lunch period four (4) hours after the designated starting time, shall constitute the workday. Five (5) such days, Monday through Friday, shall constitute the workweek.

Section 10.02. The Business Manager(s) and the Employer must agree that the application of the four ten-hour workweek would provide mutual benefit to the employees, the Employer and the Client. If the parties agree to work the four ten-hour workweek, the following apply and shall modify Article X, Section 10.01.

(A). Ten (10) consecutive hours shall constitute a day's work between the hours of 6:00 a.m. and 6:00 p.m., Monday through Thursday inclusive, unless otherwise changed by mutual consent in writing between

the Business Manager(s) and the Employer. One-half (1/2) hour shall be set aside for an unpaid lunch period five (5) hours after the normal starting time.

(B). ONLY due to inclement weather or time lost as a result of customer requirements may Friday be used as a make up day if the normal scheduled workweek was interrupted and time lost of five (5) hours or more was incurred by employees covered under the terms of this Agreement.

(C). In the event that Friday qualifies as a make up day, the parties hereby agree that said Friday will be scheduled as the make-up day, and the Employer agrees to schedule work to fulfill at least the lost time incurred by inclement weather during the workweek.

(D). Shift work as defined in Article X; Section 10.07, shall not be applicable to this work schedule.

Section 10.03. All work performed outside of the stated hours and on Saturdays will be paid at one and one-half (1½) times the regular straight-time rate; Sundays and the following holidays shall be paid at two (2) times the straight-time rate: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Day after Thanksgiving, Christmas Day or days celebrated as such.

Section 10.04. No work shall be performed on Labor Day except in case of an emergency.

Section 10.05(a). Employees shall report to the job-site or shop ready for work at the designated starting time. The Employer agrees to pay employees for time elapsed between the designated starting time and the time at which they are returned to headquarters not including the intermission for lunch.

(b). The Employer shall set up headquarters in the nearest suitable location to the job. A suitable place to eat and change clothes shall

be provided by the Employer. It shall be heated in the winter and large enough to accommodate employees and their tools.

Section 10.06. Employees reporting for work who have not been notified at least two (2) hours prior to the normal scheduled starting time of the same day, and adverse weather or ground conditions prevent them from working, shall be compensated a minimum of two (2) hours at their regular rate of pay. The employees shall remain at the reporting point and are to perform such tasks as assigned. The Employer has the right to suspend work for other reasons beyond his control after giving timely notice to employees.

Section 10.07. Shift Work. When so selected by the Employer, multiple shifts of at least five (5) days' duration may be worked. When two (2) or three (3) shifts are worked:

The first shift (day shift) shall be worked between the hours of 8:00 a.m. and 4:30 p.m. Workers on the day shift shall receive eight (8) hours' pay at the regular rate for eight (8) hours' work.

The second shift (swing shift) shall be worked between the hours of 4:30 p.m. and 12:30 a.m. Workers on the swing shift shall receive eight (8) hours' pay at the regular hourly rate plus 10% for seven and one-half (7-1/2) hours' work.

The third shift (graveyard shift) shall be worked between the hours of 12:30 a.m. and 8:00 a.m. Workers on the "graveyard shift" shall receive eight (8) hours' pay at the regular hourly rate plus 15% for seven (7) hours' work.

A lunch period of thirty (30) minutes shall be allowed on each shift. All overtime work required after the completion of a regular shift shall be paid at one and one-half (1½) times the "shift" hourly rate.

There shall be no pyramiding of overtime rates and two (2) times the straight-time rate shall be the maximum compensation for any hour worked. There shall be no requirement for a day shift when either the second or third shift is worked.

Section 10.08. The Employer shall furnish all tools and equipment (except those tools required by Local Union Agreement(s), which the employee must have on the job) required to perform work covered by this Agreement. Such tools, equipment, ropes and safety devices shall be of suitable types and size, in good working condition and in sufficient quantity to properly and safely perform work covered by this Agreement.

Section 10.09. It is the Employer's exclusive responsibility to ensure the safety of its employees and their compliance with safety rules and standards.

Section 10.10. Employees shall install all work in a safe and workmanlike manner and in accordance with applicable code and contract specifications.

ARTICLE XI

Wages, Pay Provisions, Benefits and Pre-Bid Conference

Section 11.01. Wages shall be paid to employees weekly before quitting time on payday. If payday is a holiday, they shall be paid before quitting time on the previous day. Any employee laid off or discharged shall be paid all his wages immediately. In the event he is not paid off, as provided above, waiting time at the appropriate rate shall be charged until payment is made. A payday shall be established which is mutually agreeable to the Employer and the Union.

Section 11.02. Employees who terminate their employment may be made to wait until the regular payday for their wages. Unless otherwise arranged, such wages may be mailed to the permanent address of such employee.

Section 11.03. Deductions from wages shall be only those provided or authorized by law and/or those authorized, in writing, by the individual employee.

Section 11.04. The minimum hourly rate of wages shall be determined at a Pre-Bid Conference held in the jurisdiction of the Local Union(s) in whose jurisdiction wind turbines will be erected. The respective IBEW International Vice President(s) and the affected Local Union(s) shall establish the wage rate for Outside and Inside employees.

Section 11.05. A Groundman, when directed, shall assist a Journeyman Lineman or Lineman in the performance of his work on the ground, including the use of hand tools furnished by the contractor. Under no circumstances shall employees in this classification climb poles, towers, ladders, or work from an elevated platform or bucket truck. However, employees in this classification may perform tower assembly on the ground. There shall be no established ratio of Groundmen to Linemen.

Section 11.06. The Employer adopts and agrees to be bound by the written terms of legally established trust agreements specifying the detailed basis on which payments are to be made into, and benefits paid out of, such trust funds. The Employer authorizes the parties to such trust agreements to appoint trustees and successor trustees to administer the trust funds and hereby ratifies and accepts the trustees so appointed as if made by the Employer. The Employer agrees to be bound by and will sign all legally constituted trusts which have been established by the Local Union Agreement(s).

Section 11.08. Pre-Bid Conference. A Pre-Bid Conference is required for each job on which the Employer wishes to utilize this Agreement. It shall be set up by the Employer(s) requesting use of the Agreement. The Pre-Bid Conference shall include the Employer(s), the respective IBEW International Vice President(s) and the affected Local Union(s).

The Employer is required, at the Pre-Bid Conference, to provide the affected Local Union(s) with a list of employees who may be used, pursuant to Section 7.02, during the job or project being considered.

ARTICLE XII

NLMCC

Section 12.01. The parties agree to participate in the NECA-IBEW National Labor-Management Cooperative Fund, under the authority of Section 6(b) of the Labor Management Cooperation Act of 1978, 29 U.S.C. § 175(a), and Section 302(c)(9) of the Labor-Management Regulations Act, 29 U.S.C. § 186(c)(9). The purposes of this Fund include the following:

(A). To improve communication between representatives of labor and management.

(B). To provide workers and employers with opportunities to study and explore new and innovative joint approaches to achieving organizational effectiveness.

(C). To assist workers and employers in solving problems of mutual concern not susceptible to resolution within the collective bargaining process.

(D). To study and explore ways of eliminating potential problems which reduce the competitiveness and inhibit the economic development of the electrical construction industry.

(E). To sponsor programs which improve job security, enhance economic and community development, and promote the general welfare of the community and the industry.

(F). To encourage and support the initiation and operation of similarly constituted local labor-management cooperation committees.

(G). To engage in research and development programs concerning various aspects of the industry, including, but not limited to, new technologies, occupational safety and health, labor relations, and new methods of improved production.

(H). To engage in public education and other programs to expand the economic development of the electrical construction industry.

(I). To enhance the involvement of workers in making decisions that affects their working lives.

(J). To engage in any other lawful activities incidental or related to the accomplishment of these purposes and goals.

Section 12.02. The Fund shall function in accordance with, and as provided in its Agreement and Declaration of Trust, and any amendments thereto and any other of its governing documents. Each Employer hereby agrees to be bound by, and shall be entitled to participate in the NLMCC, as provided in said Agreement and Declaration of Trust.

Section 12.03. Each Employer shall contribute one cent (1¢) per hour worked, up to a maximum of 150,000 hours per year, for work performed under the terms of this Agreement. Payment shall be forwarded monthly, in a form and manner prescribed by the trustees, no later than fifteen (15) calendar days following the last day of the month in which the labor was performed. The _____ Chapter, NECA or its designee, shall be the collection agent for this Fund.

Section 12.04. If an Employer fails to make the required contributions to the Fund, the trustees shall have the right to take whatever steps are necessary to secure compliance. In the event the Employer is in default, the Employer shall be liable for the sum equal to fifteen percent (15%) of the delinquent payment, but not less than the sum of twenty ($20), for each month payment of contributions is delinquent to the Fund, such amount

being liquidated damages, and not a penalty, reflecting the reasonable damages incurred by the Fund due to the delinquency of the payments. Such amount shall be added to and become a part of the contributions due and payable, and the whole amount due shall bear interest at the rate of ten percent (10%) per annum until paid. The Employer shall also be liable for all costs of collecting the payment, together with attorney's fees.

ARTICLE XIII

Insurance Benefits

Section 13.01. For all employees covered by this Agreement, the Employer shall carry Workers' Compensation Insurance with an authorized company in each state where he employs workers under the terms of this Agreement, and such other protective insurance as may be required by the laws of the States in which workers are employed under this Agreement. Satisfactory proof of compliance with such laws shall be furnished to the Union upon demand. The Employer shall also make payments to the Unemployment Compensation Commission in each State where he employs workers under the terms of this Agreement.

ARTICLE XIV

Fringe Benefit Payments

Section 14.01. Any Employer who fails to make fringe benefit payments as required shall be subject to having this Agreement terminated upon seventy-two (72) hours' notice, in writing, being served by the Union, provided the individual Employer fails to show satisfactory proof that the required payments have been made. In addition, if suit is instituted to collect any delinquent payment, the Employer shall also be liable for such interest, damages, attorney's fees and costs as provided for by law.

ARTICLE XV

Wage and Fringe Benefit Bond

Section 15.01. The Employer shall furnish to the Union a surety bond in the amount of $50,000 written on a form provided by the Union to secure payment of all amounts due on account of payroll and fund deduction contribution and reporting obligations of the Employer required by this Agreement. The bond shall provide that it may not be terminated without thirty (30) days' prior written notice to the Employer and the Union.

ARTICLE XVI

Legality

Section 16.01. Should any provision of this Agreement be declared illegal by any court of competent jurisdiction, such provision shall immediately become null and void, leaving the remainder of the Agreement in full force and effect, and the parties shall thereupon seek to negotiate substitute provisions which are in conformity with the applicable laws.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed by their duly authorized representatives this _____ day of _____, 20___.

_____	_____
International Brotherhood of Electrical Workers	For the Employer

Procedures for Employers to become Signatory to the IBEW Wind Turbine Agreement (IBEW WTA).

1. All requests to become signatory to the IBEW WTA and/or requests for the use of the IBEW WTA shall be accompanied by information describing the location and scope of the project for which it is being requested and sent to the International President in writing.

2. The IBEW Construction and Maintenance Department will investigate the appropriateness of the request with the assistance of the International Vice President in whose district the Employer is headquartered, and the International Vice President in whose district the project is located. These International Vice Presidents will provide a recommendation for the consideration of the International President.

3. For requests to become signatory. If the decision to become signatory is favorable, the International President will provide the Employer with three (3) copies of the Agreement to be signed and returned.

4. The International President will provide one (1) signed copy of the Agreement to the Employer for the Employer's records, one (1) to the respective International Vice President, and one (1) copy will be retained at the International Office.

5. Requests for use of the IBEW WTA by signatory Employers. Once an Employer is signatory to the IBEW WTA, approval for use on a project must be requested for each and every individual project in accordance with Sections 1 and 2 above.

6. If the decision for requested use is favorable, the Employer will receive Conditional Approval to allow for a Pre-Bid Conference to be held in accordance with Section 11.08 of the IBEW WTA.

7. Once advised by the International Vice President for the district in which the project is located that all necessary Pre-Bid items have been agreed to, the IBEW Construction and Maintenance Department will send the Employer and the International Vice President the Approval for Use.

INTERNATIONAL BROTHERHOOD OF
ELECTRICAL WORKERS, AFL-CIO
For Submission of Reports and Payment of Payroll and Fund
Contributions and Deductions as described in the Collective Bargaining Agreement

Bond # _____

KNOW ALL PERSONS BY THESE PRESENTS, that we

_____
(Name and Address of Principal)

as Principal and _____
(Name of Surety)

are held and firmly bound unto the International Brotherhood of Electrical Workers, AFL-CIO (hereinafter "IBEW"), located at 1125 15th Street, N.W., Washington, D.C. 20005, as Obligee, in the sum of Fifty Thousand ($50,000.00) Dollars, lawful money of the United States of America, for the payment of which sum, well and truly to be made, we bind ourselves, and heirs, administrators, executors, successors and assigns, jointly and severally, firmly by these presents.

SIGNED, SEALED and dated this _____ day of _____, 2004.

WHEREAS, the above Obligee has required the Principal to furnish reports and to pay the payroll due the employees of the Principal who are represented by the IBEW and/or the applicable IBEW Local Union(s), and to pay fund contributions and deductions to the applicable trust funds and/or IBEW Local Union(s), which Principal is obligated by such collective bargaining agreement to pay for a period from acceptance by it or on its behalf to its expiration, during which this bond remains in force, subject to the following conditions:

(1) That the Surety may cancel its liability as to future assessments under this bond (including renewal thereof) at any time by giving written notice to the Principal and Obligee at least thirty days in advance of the date of such expiration or cancellation; failure of the Principal to maintain such bond (by renewal) in full force and effect until the expiration date of the appropriate collective bargaining agreement shall not cancel the Surety's liability hereunder except as provided hereinabove by the fifteen days advance notice provision.

(2) That liability of the surety under this bond to the Obligee for one or more defaults of the Principal shall not exceed in the aggregate the sum of this bond.

(3) That no suit, action or proceeding shall be maintained against the Surety hereunder, unless the same be instituted within twelve months after date of expiration or cancellation of the bond (including renewal thereof).

(4) That payments shall be fully made as required by the applicable collective bargaining agreement at which time, if not then fully paid, shall be delinquent. The full sum of $50,000.00 shall then be paid the Surety to the IBEW upon notice by the President of the IBEW that the Principal is delinquent, and the Surety shall be entitled to a refund, if any, only when the Principal has filed the necessary reports and the precise obligation thereunder determined, and fulfilled its payroll and fund contribution and deduction obligations less liquidated damages, if applicable, all attorney's costs, all accountant's costs, and all other costs and expenses in the matter.

ATTACHMENT:

Power of Attorney and Certificate of Authority of Attorney(s)-in-Fact of Bonding Company.

_____

_____
(Principal)

_____
(Surety)

BY: _____

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

EXHIBIT
Interwest
admitted

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-08-0172

Direct Testimony of

Amanda Ormond

on behalf of Interwest Energy Alliance

Docket No. E-01345A-08-0172

July 1, 2009

Direct Testimony of Amanda Ormond
Docket No. E-01345A-08-0172

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Direct Testimony of Amanda Ormond
on behalf of Interwest Energy Alliance
Docket No. E-01345A-050816

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS?

A. My name is Amanda Ormond. My business address is 7650 S. McClintock Drive, Suite 103-282, Tempe, Arizona 85284.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a consultant to Interwest Energy Alliance (Interwest) and serve as their Southwest Representative. I assist Interwest on issues related to electrical utilities and utility regulation.

Q. PLEASE DESCRIBE INTERWEST ENERGY ALLIANCE.

Interwest Energy Alliance (Interwest) is a 510(c)(6) trade association representing the interests of non-governmental organizations and renewable energy developers and product manufacturers; primarily wind and solar. Interwest works through education and advocacy to create state-level policies supporting renewable energy development. The organization concentrates its work in the states of Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.

A. WHAT IS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE RELATED TO YOUR TESTIMONY.

I have worked in the energy and environmental field for 20 years in Arizona. In the mid '80s I was a quality control specialist for an environmental consulting firm and focused on groundwater contamination evaluation and remediation projects. From 1987 to 2001 I was employed by the State Energy Office, a division of the Arizona Department of Commerce. I was appointed director in 1994 were I served for seven years. In 2001 I started the Ormond Group, LLC a consulting firm specializing in energy and environmental policy development, strategy and education. I hold a BS degree in Environmental Earth Science. I have participated extensively in regional and local stakeholder processes and policy forums as an expert in renewable and energy efficiency and have spent 10 years writing and lobbying for energy legislation. I have also represented the wind industry for four years.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides an overview of the reasons that Interwest signed on to and supports the Arizona Public Service Company Proposed Settlement Agreement dated June 12, 2009. My testimony provides comments on the renewable energy portions of the settlement, various other sections of the settlement, and some of the issues raised in Chairman Mayes' June 9 letter to Parties to the Docket.

Q. WHEN DID INTERWEST BECOME AN INTERVENOR IN THE CASE?

A. Interwest applied to intervene on January 30, 2009. The Arizona Corporation Commission (ACC) granted Interwest permission to intervene on February 10, 2009. Interwest participated actively from the start of settlement negotiations. Interwest decided to participate in this case because renewable energy and energy efficiency issues were added into the negotiations mix.

Q. DID INTERWEST CONSIDER THE SETTLEMENT PROCESS FAIR?

Interwest was able to participate fully in settlement negotiations. We believe that the settlement process was fair and that Interwest was allowed the opportunity to present and have considered our view and priorities related to clean energy and energy efficiency. Interwest supports the proposed settlement and believes that the settlement represents a reasonable compromise among divergent parties and interests. We believe it will also provide long-term benefits for Arizona Public Service Company ("the Company") and its customers.

Renewable Energy Provisions

Q. IN THE SETTLEMENT THE COMPANY WILL BE REQUIRED TO OBTAIN RENEWABLE ENERGY BEYOND THE REQUIREMENTS OF THE RENEWABLE ENERGY STANDARD AND TARIFF (REST). WHY DO YOU SUPPORT THIS PROVISION?

A. First, the REST rule (Decision No. 69127) establishes a standard for regulated utilities to obtain renewable energy for a minimum of 15% of retail energy sales. The standard was designed as a minimum in the recognition that if, renewable energy resources were of benefit to customers, the utility should not be precluded from obtaining more than the set 15% of retail energy sales. The Company is exercising the option, granted by the ACC in the REST rules, to exceed the standard.

Second, the amount of renewable energy, to be obtained by the Company, (1.7 million megawatt hours by December 31, 2015) was chosen as a result of an extensive internal evaluation process and subsequent vetting with interested parties . The amount proposed is consistent with the voluntary Resource Plan Report filed by APS with the ACC on January 29, 2009[1]. To develop this plan the company hosted six months of workshops for stakeholders to understand the energy landscape and resources choices, and be able to provide input to the company on a wide-range of energy issues. The workshops included topics such as load growth and resource needs, polices and trends, resource availability and costs, and risks factors and risk mitigation strategies.

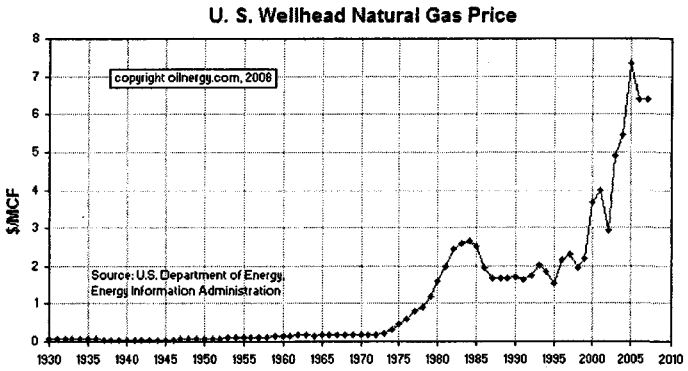
The Resource Plan states the following factors, among others, are to be considered in choosing the type and amount of resources to meet load growth that is outlined in the Plan: cost, diversity of resources, financial stability, resource self-sufficiency, and positioning for climate change policy.[2]

[1] APS Resource Plan Report, January 29, 2009, Appendix 1, Table 1 – Loads and Resources Table – Docket No. E-01345A-09-0037

[2] APS Resource Plan Report, January 29, 2009, page 5

Third, wind and solar resources are carbon-free resources. Pending congressional legislation will require carbon dioxide to be a heavily regulated pollutant. As such APS, and other utilities, will be subject to new rules, regulations and costs to mitigate C02 and related emissions. Arizona routinely experiences one of the highest growth rates of electricity in the county. If APS chooses to add new carbon-based resources to meet load growth it will increase the amount of carbon that will need to be mitigated. By adding 1.7 million MWhs of carbon-free renewable energy, the Company is reducing its future carbon risk and cost of carbon mitigation; a cost that consumers will have to bear.

Fourth, the renewable energy resources which would be obtained under this Settlement, if approved, will increase the amount of price-stable resources in the Company's resource mix. The cost of energy from natural gas, coal and nuclear power plants is subject to change based, in large measure, to the cost of fuel to run the power plant. As fuel prices fluctuate and increase over time the price of electricity changes. In the past decade the price of natural gas has risen substantially which has had a dramatic effect on the cost of electricity generated from natural gas facilities.



http://www.oilnergy.com/1gnymex.htm

OILNERGY.COM, Post Office 80456 Austin, Texas 78708

Because renewable energy facilities (with the exception of biomass plants) do not require a long-term purchased fuel source, the price of energy from a solar, wind or geothermal power plant remains stable for the life of the facility or energy purchase contract.[3] In 2015, with 1.7 million MWh of renewable energy generation, the Company will have approximately 1/10 of the utility's energy generated by energy sources that are not subject to variable or increasing fuel costs.

Q. THE SETTLEMENT OUTLINES A NUMBER OF SPECIFIC RENEWABLE ENERGY PROJECTS. DOES INTERWEST SUPPORT THESE PROJECTS?

[3] Twenty to thirty years is typical for a Purchase Power Agreement (PPA). A PPA may include a price escalator for inflation but this rate is known at the time the contract is signed.

Yes. We support the projects because they represent a diversity of technologies and applications, and will demonstrate proven technology. The proposed projects include a possible in-state utility-scale wind project (Section 15.2), a utility-scale photovoltaic project (Section 15.3), distributed solar generation projects at K-12 schools (Section 15.5), and distributed solar generation projects for government institutions (Section 15.6). The technology types could include flat plate or silicon based photovoltaics, commercial-scale hot water systems, utility-scale wind turbines and tracking or fixed commercial day lighting systems. These systems will be deployed in large increments (considered utility-scale) and as distributed systems. The technologies will be applied in K-12 schools and commercial government facilities.

Wind and photovoltaic technology, the youngest technologies, are proven and widely deployed. According to the Arizona Economic Resource Organization (AERO), Solar Task Force Report, "Photovoltaic industry revenues will exceed $20 billion in 2008, and have grown at a compound annual rate in excess of 45% over the past five years. Nearly 5GW of photovoltaic solar power will be produced in 2008." [4]

The American Wind Energy Association reports that the U.S. wind energy industry broke records in "2008 by installing over 8,500 megawatts (MW) of new generating capacity (enough to serve over two million homes), increasing the nation's total wind power generating capacity by 50% to over 25,300 MW and channeling an investment of some $17 billion into the economy. For the fourth year, wind power was second only to natural gas in terms in new capacity added."[5]

Q. ARE THERE OTHER BENEFITS OF THESE PROJECTS?

A. Yes. The projects outlined in the settlement will have educational benefits for customers. As designed, projects will be installed at public schools and government facilities. Students, parents and teachers at the schools and employees and visitors to government institutions, can be educated about photovoltaic, solar hot water and solar day lighting applications. It is anticipated that these demonstrations will lead to increased interest in distributed energy systems by APS customers and help the utility meet its distributed energy requirement under the REST.

Q. ARE THERE OTHER ELEMENTS OF THE SETTLEMENT THAT WILL FACILITATE DEVELOPMENT OF RENEWABLE ENERGY RESOURCES?

A. Yes, the immediate planning of transmission for renewable energy resources is critical to help the Company meet the established goals. Section 15.4 specifies that the Company will "commence permitting, design, engineering, right of way acquisition, regulation authorization (which may include a request to FERC for applicable transmission incentives and other cost recovery provisions), and line siting for one or more new transmission lines or upgrades designed to facilitate delivery of solar and other renewable resources to the APS system"

---

[4] Arizona Economic Resource Organization (AERO), Solar Task Force Report, November 12, 2008, Page 4

[5] American Wind Energy Association, Market Update Fact Sheet, 2008, Page 1, http://www.awea.org/pubs/factsheets/Market_Update_Factsheet.pdf

Historically, the lead time for developing new fossil power plants is similar to, and can be coordinated with, the construction of new transmission lines. However, renewable energy generation resources can be sited, developed and constructed in much less time than is needed to build new transmission lines (Appendix 1). Thus, a timing mismatch is created (often referred to as a chicken and egg problem). If transmission service is going to be available for renewable energy generators at the time the plants come on line, then transmission planning must precede renewable energy project development.

As directed by the ACC in the 2009 Biennial Transmission Assessment (Decision No. 70635), the Company has been working to identify transmission that is needed to transmit renewable energy resources to the load center. The transmission commitment in the settlement will help ensure that transmission capacity is available when needed.

Other Settlement Provisions

Q. HOW ARE CUSTOMERS TO BE ENSURED THAT THE RENEWABLE ENERGY STANDARD AND ENERGY EFFICIENCY STANDARDS ARE BEING MET?

A. The settlement includes performance measures for the company to meet. These include, but are not limited to, meeting the current Renewable Energy Standard and Tariff and the energy efficiency goals set forth in the settlement. Progress toward the performance measures will be submitted by the company annually and the report will allow for the periodic review of program activity and progress. In addition entities such as Interwest will also monitor the Company's compliance.

Q. DO YOU HAVE AN OPINION ON THE RETENTION OF $10 MILLION IN BASE RATES FOR DEMAND SIDE MANAGEMENT (DSM) AS STIPULATED IN SECTION 3.11 OF THE SETTLEMENT AGREEMENT?

A. Yes, we believe it is appropriate that $10 million is retained in based rates and not shifted to the DSM Adjuster Mechanism (DSMAC).

The capital cost for traditional, mainstream resources, such a natural gas or coal, is funded in base rates. As DSM, energy efficiency and renewable energy resources continue to become more mainstream it is appropriate they these resources receive similar rate treatment. Since the total costs for the DSM or renewable resources may not be known at the time of a rate case, it is reasonable that a portion of the costs be placed in base rates and the remainder be allowed to flow though a more flexible funding mechanism, such as an adjuster.

A primary reason to support clean energy resources in base rates is to provide stability for the Company and certainty for regulators. Inserting the costs of DSM and renewable energy in base rates ensures a fixed amount of funds for the Company for projects. For the regulator, having a set amount in base rates provides transparency for the costs of clean energy resources. In the future, Interwest recommends that, to the extent possible, capital for clean energy projects be recovered in base rates and minimized in adjuster mechanisms.

Q. CAN YOU COMMENT ON THE PURPOSE OF SECTION 15.8 RELATED TO SUPPORT FOR THE REST RULES?

A. Section 15.8 is intended to create stability in policy for the Company to pursue renewable energy resources. Sections 15.1 – 15.7 require actions that are spurred, in part, by the REST. The Company will be making substantial, long-term investments in energy from renewable energy resources to meet the REST and the commitments of Sections 15.1-15.7. Section 15.8 provides the Company with assurance that the projects in this settlement are appropriate to pursue even if the REST is challenged.

Chairman Mayes' June 9 letter to Parties to the Docket

Q. CAN YOU PLEASE ADDRESS BULLET EIGHT OF CHAIRMAN MAYES' LETTER RELATED TO THE ADOPTION OF THE REST RULES IN THIS SETTLEMENT?

A. Interwest supports the adoption of the REST rules in this settlement. The majority of Interwest members are businesses that develop renewable energy projects and/or manufacture renewable energy equipment. Our businesses find that market stability is a critical factor driving investment decisions. Our member companies prefer to work and invest in markets that have stable business climates, clear and certain market rules, and long term commitments in renewable energy. Arizona is an attractive market to developers and manufactures because of the high historic growth rate in energy demand. However, current legal challenges to the REST rules create a level of uncertainly in the market place. Interwest believes that it is beneficial for our members, APS and its consumers to create market stability, by ensuring that the goals made in the REST are supported in this Settlement, so as to survive any legal challenge.

Q. CHAIRMAN MAYES ASKS IF PARTIES (INTERWEST) "WOULD <u>OBJECT</u> TO THE COMMISSION REQUIRING THAT APS EXCEED THE RES, SUCH THAT THE COMPANY WOULD SECURE 8.813 MILLION MWH OF RENEWABLE ENERGY BY THE YEAR 2025."

Interwest supports the Settlement as written. Interwest would not object if the Commission chose to impose a higher renewable energy standard in this, or another forum or process.

Q. DOES INTERWEST BELIEVE IT IS IN THE PUBLIC INTEREST TO ADOPT A FEED-IN TARIFF PILOT PROGRAM FOR BUSINESSES OR IN AREAS OF THE STATE THAT WILL SEE SIGNIFICANT GROWTH?

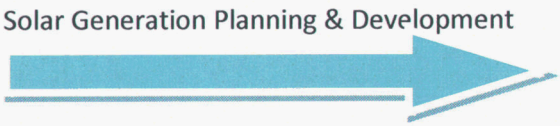
A. Feed-in Tariffs (FIT) are in use in the counties of Spain and German and in several states; California and Florida. Each program is targeted for a specific outcome. Interwest believes that to develop an effective FIT an evaluation process should take place to analyze the pros and cons of various systems and determine if a FIT would be more effective than the current incentives offered by Arizona's electric utilities.

Q. Does this conclude your testimony?

A. Yes, and I thank the ACC for authorizing Interwest's intervention and participation in the proceeding.

Appendix I.

Scenario One



Solar generation must wait for transmission

Scenario Two

Transmission development must begin before solar projects are planned and developed.

Solar energy generation can be built much faster than transmission, thus transmission planning and development needs to start well before the planning and development for solar energy projects.

BOEHM, KURTZ & LOWRY
ATTORNEYS AT LAW
36 EAST SEVENTH STREET
SUITE 1510
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255

TELECOPIER (513) 421-2764

EXHIBIT
Kroger-1
ADMITTED

FILE COPY

Via Overnight Mail

June 29, 2009

Arizona Corporation Commission
Attn: Docket Filing Window
1200 Washington Street
Phoenix, AZ 85007

Re: Docket No. E-01345A-08-0172

Dear Sir or Madam:

Please find enclosed the original and thirteen (13) copies of the *SUPPLEMENTAL DIRECT* TESTIMONY OF STEPHEN J. BARON on behalf of THE KROGER CO. filed in the above-referenced matter.

All parties of record have been served. Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

John William Moore, Jr.,
Arizona Bar No. 021942

MLKkew
Attachments

G:\WORK\MLK\KROGER\ARIZONA\E-01345A-08-0172 (Arizona Public Service Co.)\Commission ltr.doc

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by regular U.S. mail (unless otherwise noted), this 29TH day of June, 2009 on the parties listed on the attached service list.

Company	Contact	Address
	Nicholas Enoch	349 N. Fourth Ave. Phoenix, Arizona 85003
	Cynthia Zwick	1940 E. Luke Avenue Phoenix, Arizona 85016
	Scott Canty	The Hopi Tribe Kykotsmovi, Arizona 86039
	Jeffrey Woner	K.R. SALINE & ASSOC., PLC Mesa, Arizona 85201
	Daniel Pozefsky	1110 West Washington, Suite 220 Phoenix, Arizona 85007
	Jason Moyes	1405 W. 16th Street Yuma, Arizona 85364
	Arizona Reporting Service, Inc.	2200 N. Central Ave. -502 Phoenix, Arizona 85004-1481
	Janice Alward	1200 W. Washington Phoenix, Arizona 85007
	Timothy Hogan	202 E. McDowell Rd. - 153 Phoenix, Arizona 85004
	David Berry	P.O. Box 1064 Scottsdale, Arizona 85252-1064
	Jeff Schlegel	1167 W. Samalayuca Dr. Tucson, Arizona 85704-3224
	Michael Curtis	501 East Thomas Road Phoenix, Arizona 85012-3205
	Michael Grant	2575 E. Camelback Rd. Phoenix, Arizona 85016-9225
	Gary Yaquinto	Arizona Utiltiy Investors Association Phoenix, Arizona 85004
	Lawrence Robertson, Jr.	2247 E. Frontree Rd., Suite 1 Tubac, Arizona 85646
	C. Webb Crockett	3003 N. Central Ave. - 2600 Phoenix, Arizona 85012-2913
Arizona Corporation Commission	Lyn Farmer	1200 W. Washington Phoenix, Arizona 85007-2927
Arizona Corporation Commission	Ernest Johnson	1200 W. Washington Phoenix, Arizona 85007-2927
Arizona Public Service Company	Thomas Mumaw	PO Box 53999 Phoenix, Arizona 85072-3999

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.

BEFORE THE

ARIZONA CORPORATION COMMISSION

Kristin K. Mayes, Chairman
Gary Pierce
Paul Newman
Sandra D. Kennedy
Bob Stump

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	**) Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	**)**
AND REASONABLE RATE OF RETURN	**)**
THEREON, TO APPROVE RATE SCHEDULES	**)**
DESIGNED TO DEVELOP SUCH RETURN	**)**

SUPPLEMENTAL DIRECT TESTIMONY OF STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA
July 2009

BEFORE THE

ARIZONA CORPORATION COMMISSION

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	)	**Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	)	
AND REASONABLE RATE OF RETURN	)	
THEREON, TO APPROVE RATE SCHEDULES	)	
DESIGNED TO DEVELOP SUCH RETURN	)	

SUPPLEMENTAL DIRECT TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Have you previously submitted testimony in the proceeding?

A. Yes. I submitted Direct Testimony.

Q. What is the purpose of your Supplemental Direct Testimony?

1 A. I will be presenting brief testimony in support of the Proposed Rate Settlement
2 Agreement of June 12, 2009 ("Settlement Agreement"). Kroger Company is a
3 signatory to this agreement and fully supports the settlement for the reasons that I
4 will discuss below. Kroger did not present testimony on the overall level of APS'
5 revenue requirement increase. Our testimony was limited to the allocation of the
6 overall approved revenue increase to rate classes ("revenue spread") and to specific
7 rate design issues affecting general service rates. Consistent with this prior
8 testimony, my Supplemental Direct testimony will only address these issues within
9 the context of the Settlement Agreement. Notwithstanding this, Kroger supports the
10 entire settlement and believes that it will result in reasonable rates.

11 **Q. Have you specifically reviewed the provisions of the Settlement Agreement**
12 **regarding revenue spread?**

13 A. Yes. The Settlement Agreement requires a uniform percentage revenue increase to
14 each retail rate schedule. Based on my review of the Company's filed class cost of
15 service study, I believe that this is a reasonable settlement result. There are also
16 specific provisions that govern the increases within the E-32 rate schedule, which is
17 delineated by kW demand into four sub-groups. These provisions of the settlement
18 are reasonable and consistent with the class cost of service study results presented by
19 the Company in this case.

1 **Q. Have you reviewed the proposed settlement rate design for general service Rate**
2 **E-32?**

3 A. Yes. The settlement requires that the demand and energy charges for the
4 largest sub-group of Rate E-32 ("401 + kW") receive equal percentage
5 increases in the demand and energy charges, coupled with APS' proposed
6 customer charge. I support this proposal and believe that it is reasonable and
7 appropriate. I therefore fully support and recommend approval of the
8 Settlement Agreement.

9 **Q. Are there additional reasons why you believe that the Commission**
10 **should approve the Settlement Agreement?**

11 A. Yes. The rate case moratorium provision, preventing APS from filing a new
12 base rate case prior to June 1, 2011 is likely to be of significant benefit to all
13 of the Company's ratepayers.

14 **Q. Does that complete your testimony?**

15 A. Yes.

5050-120

BOEHM, KURTZ & LOWRY

ATTORNEYS AT LAW
36 EAST SEVENTH STREET
SUITE 1510
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255

TELECOPIER (513) 421-2764

EXHIBIT
Kroger - 2
ADMITTED

Via Overnight Mail

January 8, 2009

Arizona Corporation Commission
Attn: Docket Filing Window
1200 Washington Street
Phoenix, AZ 85007

Re: Docket No. E-01345A-08-0172

Dear Sir or Madam:

Please find enclosed the original and thirteen (13) copies of the DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON on behalf of THE KROGER CO. filed in the above-referenced matter.

All parties of record have been served. Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

John William Moore, Jr.,
Arizona Bar No. 021942

MLKkew
Attachments

G:\WORK\MLK\KROGER\ARIZONA\E-01345A-08-0172 (Arizona Public Service Co.)\Commission ltr.doc

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by regular U.S. mail (unless otherwise noted), this 8TH day of January, 2009 on the parties listed on the attached service list.

Company	Contact	Address
	Nicholas Enoch	349 N. Fourth Ave. Phoenix, Arizona 85003
	Cynthia Zwick	1940 E. Luke Avenue Phoenix, Arizona 85016
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Arizona Public Service Company	Thomas Mumaw	PO Box 53999 Phoenix, Arizona 85072-3999

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.

BEFORE THE

ARIZONA CORPORATION COMMISSION

Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

IN THE MATTER OF THE APPLICATION OF	**)**
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THEREON, TO APPROVE RATE SCHEDULES	**)**
DESIGNED TO DEVELOP SUCH RETURN	**)**

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

January 2009

BEFORE THE

ARIZONA CORPORATION COMMISSION

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	)	**Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	)	
AND REASONABLE RATE OF RETURN	)	
THEREON, TO APPROVE RATE SCHEDULES	)	
DESIGNED TO DEVELOP SUCH RETURN	)	

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida.

In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

1

2 I have presented testimony as an expert witness in Arizona, Arkansas, Colorado,
3 Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan,
4 Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North
5 Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Wisconsin; before the
6 Federal Energy Regulatory Commission and in United States Bankruptcy Court. A
7 list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-
8 1).

9

10 **Q. Have you previously presented testimony before the Arizona Corporation**
11 **Commission?**

12

13 A. Yes. I presented testimony in two previous Arizona Public Service Company rate
14 cases on behalf of Kroger Co. in 2004 and in 2006 (Docket Nos. E-01345-03-0437
15 and E-01345A-05-0816). I also presented testimony in two Tucson Electric Power
16 Company proceedings; in 1981 on behalf of the Commission (Docket No. U-1933I)
17 and in 2008 on behalf of Kroger Co. (Docket No. E-01933A-07-0402).

18

19 **Q. On whose behalf are you testifying in this proceeding?**

20

1 A. I am testifying on behalf of the Kroger Co. Kroger has approximately 36 stores in
2 the APS service territory operating under the names Fry's, Fred Meyer and Smith's.
3 These stores consume in excess of 100 million kWhs per year on the APS system.
4
5 **Q. What is the purpose of your testimony?**
6
7 A. I will be presenting testimony on the Company's class cost of service study, the
8 allocation of the proposed revenue increase to rate schedules and APS's proposal to
9 disaggregate the E-32 General Service rate into 4 separate rates.
10
11 In general, though I believe that the 4 Coincident Peak class cost of service
12 methodology used by APS in prior cases is more appropriate for allocating costs to
13 rate classes, I accept the Company's Average and Excess Demand method in this
14 case.[1] However, as I will discuss, the Company's cost study shows that there are
15 substantial differences between the rates paid by some customers and the cost to
16 provide service. In particular, residential customers are currently receiving very
17 substantial dollar subsidies from general service customers. Despite this finding, the
18 Company's proposed increases to its Residential and General Service rate classes do
19 not provide a material level of mitigation to this disparity between cost of service
20 and rates. I will address this issue and recommend that the Commission adopt a

[1] Kroger is not presenting testimony on the Company's requested revenue increase in this case. For purposes of my testimony, I have utilized the APS requested increase of $448 million. This should not be construed as an endorsement of the Company's requested increase.

specific level of subsidy reduction, based on the class cost of service results, in its determination of the increases to each rate schedule.

With regard to rate design, I will discuss the APS's proposed revisions to rate E-32; specifically the proposal to disaggregate the rate by kW demand levels. As I will discuss, Kroger supports the Company's proposed E-32 rate design and recommends that the Commission adopt it in this case.

Q. Would you please summarize your recommendations?

A. Yes.

- **For the purposes of assessing the reasonableness of the Company's proposed allocation of the revenue increase to rate schedule in this case, APS' proposal to use an Average and Excess Demand ("AED") class cost of service method is reasonable. The AED method is a traditional cost of service method that recognizes the role of both customer kW demand and energy in cost causation. Unlike other weighted demand and energy methodologies, the AED method gives a reasonable weighting to the importance of class demands in the allocation of the system's fixed production costs to rate classes.**

- **Though APS has given some recognition to the cost of service results in its proposed rate schedule increases in this case, it is appropriate to make some additional progress towards eliminating the subsidies contained in present rates in this case. A reasonable and balanced approach would be to reduce class subsidies by 25% as a means of moving towards the objective of setting rates based on cost of service. Eliminating 25% of the subsidy would result in an increase to residential customers of $259.9 million (19.3%), while producing a $180.0 million increase (14.5%) to the general service class if the full increase proposed by APS were adopted.**

- **APS is proposing to disaggregate its Rate E-32 into four separate rates delineated by kW demand levels. The Company's proposal is reasonable and should be adopted by the Commission. Because load characteristics are different for these General Service customers, the Company's proposal provides a more reasonable rate design that reflects cost of service and reduces intra-class subsidies among General Service customers.**

II. REVENUE ALLOCATION AND COST OF SERVICE

Q. Have you reviewed the Company's 12 month ending December 2007 test year cost of service study filed in this proceeding?

A. Yes. The Company is utilizing a traditional Average and Excess Demand ("AED") class cost of service study in this proceeding to allocate production related demand costs. In prior cases, APS has used a 4 CP allocation method because of the pronounced demands on the system during the summer months.[2] In the prior two APS base rate cases, I supported the Company's use of the 4 CP method and continue to do so in this case. The fact that the Company is continuing to rely on the 4 CP methodology to allocate jurisdictional costs indicates that it is an appropriate methodology for APS, given the load characteristics of the system and the significance of summer peak loads on generation costs.

Q. Do you believe that the Company's proposal to use the AED method for retail class cost of service allocation provides a reasonable basis to evaluate the relationship between the rates being charged each rate class and the underlying cost of providing service to these customers?

[2] APS is continuing to use a 4 CP methodology in its jurisdictional cost allocation study in this case.

A. Yes, it is appropriate to use for the purpose of assessing the reasonableness of the Company's proposed allocation of the revenue increase to rate schedule in this case. The AED method is a traditional cost of service method that recognizes the role of both customer kW demand and energy in cost causation. Unlike other weighted demand and energy methodologies, the AED method gives a reasonable weighting to the importance of class demands in the allocation of the system's fixed production costs to rate classes.

Q. How should the results of the Company's class cost of service study be used in this case?

A. The purpose of an embedded, fully allocated class cost of service study is to assess the reasonableness of a utility's rates, in relation to the underlying cost of providing service to the customers on each rate class. As a matter of policy, it is both efficient and equitable to establish rates on the basis of the cost of service and, to the extent feasible, to move rates towards cost of service in a rate case in which a utility is requesting a change in revenues. In other words, a rate case, such as the current APS proceeding, is an opportunity to evaluate the Company's rates and make incremental adjustments so that, over time, each class will pay rates reflecting cost of service. In so doing, rates paid by each customer will provide efficient "price signals" reflecting the resource cost of meeting customer demands. In addition, cost based rates provide an equitable basis to assign the Company's overall revenue

1 requirement to customers. In this manner, customers in one rate class do not pay or
2 receive unjustified monetary subsidies from other rate customers.
3
4 **Q. How do the Company's current rates compare to the underlying cost of**
5 **service?**
6
7 A. A good measure of this rate versus cost relationship is the relative class rates of
8 return at present rates. This measurement, which is the ratio of a class's rate of
9 return relative to the average retail earned rate of return, provides a good summary
10 of the rate versus cost relationship, based on the results of the Company's AED cost
11 of service study.
12
13 **Q. What are the relative class rate of return results produced by the Company's**
14 **test year AED cost of service study?**
15
16 A. The table below summarizes the rates of return and the relative rate of return indices
17 ("ROR Index") for each of the major rate classes using the results of the Company's
18 AED study.

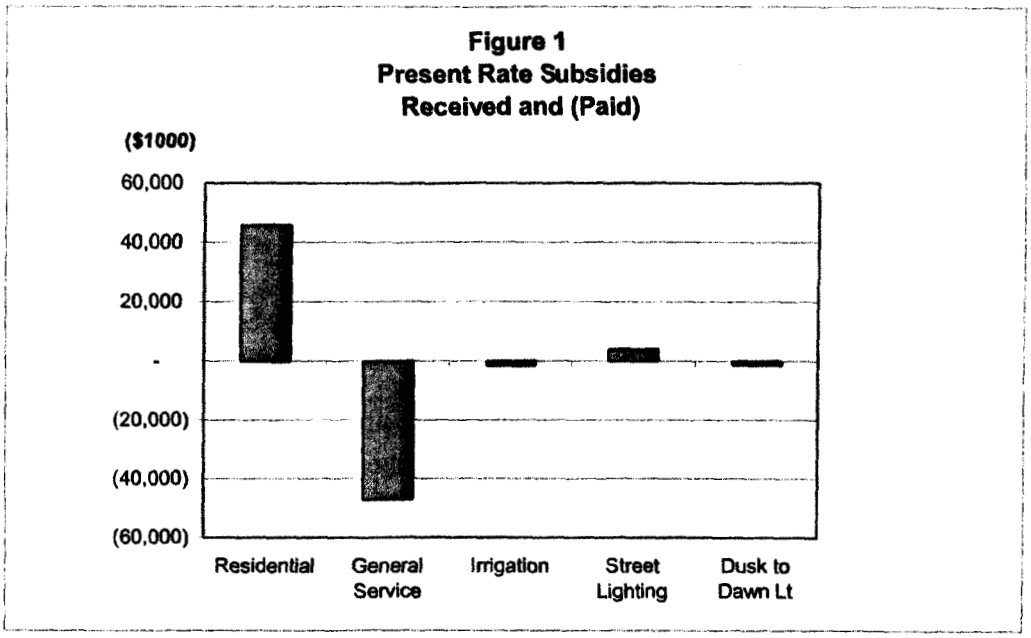
TABLE 1
Comparison of Relative Rates of Return
Average and Excess Demand Cost of Service Study
Present Rates

Class	Rate of Return	ROR Index
Residential	2.85%	0.75
General Svc	5.04%	1.33
E-20 (Church Rate)	-0.82%	(0.22)
E-32 TOU	5.93%	1.56
E-30, E-32 (0-20 kW)	3.53%	0.93
E-32 (21-100 kW)	5.67%	1.50
E-32 (101-400 kW)	5.87%	1.55
E-32 (401+ kW)	6.57%	1.73
E-34	3.48%	0.92
E-35	-0.50%	(0.13)
Irrigation	6.91%	1.82
Street Light	-0.03%	(0.01)
Dusk to Dawn	6.61%	1.74
Total Retail	3.79%	1.00

Based on these results, the residential class is paying only 75% of its allocated cost of service under present rates, while general service customers are paying a relative rate of return that is approximately 130% of the system average. This is a substantial difference and one that should be addressed in this rate proceeding. More significantly, within the General Service rate class, customers on rate schedules E-32 (M) and E-32 (L) are paying significantly higher subsidies than the General Service class as a whole. As can be seen, customers on E-32 M (101 to 400 kW demands) and E-32 L (greater than 400 kW demands) are paying relative rates of return at present rates of 155% and 173% of the system average.

Q. Have you computed the dollar subsidies being paid and received by each rate class at present rates, based on the results of the Company's cost of service study?

A. Yes. Figure 1 below shows the dollar subsidies paid and received at present rates. As can be seen, the residential class is receiving (shown as a positive value) over $45 million in subsidies at present rate from other rate classes. At the same time, general service customers pay annual subsidies of over $46 million. These results are based on the Company's filed AED class cost of service study, without any adjustments. These subsidies have actually grown over time, since the Company's last base rate case.



Q. Has APS made rate spread proposals in this case that adequately address the substantial disparities between present rates and cost of service?

A. Not in my opinion. APS is proposing to increase General Service rates at a ¼ of 1% lower percentage rate than the system average, while increasing the Residential class at a rate ¼ of 1% higher than the system average. This proposal does nothing to address the significant disparities between rates and cost of service. In fact, the Company's proposal makes matters worse. The Company is essentially proposing a uniform percentage increase for the residential and general service classes, which comprise about 98% of base revenues. This is despite the fact that the Company's

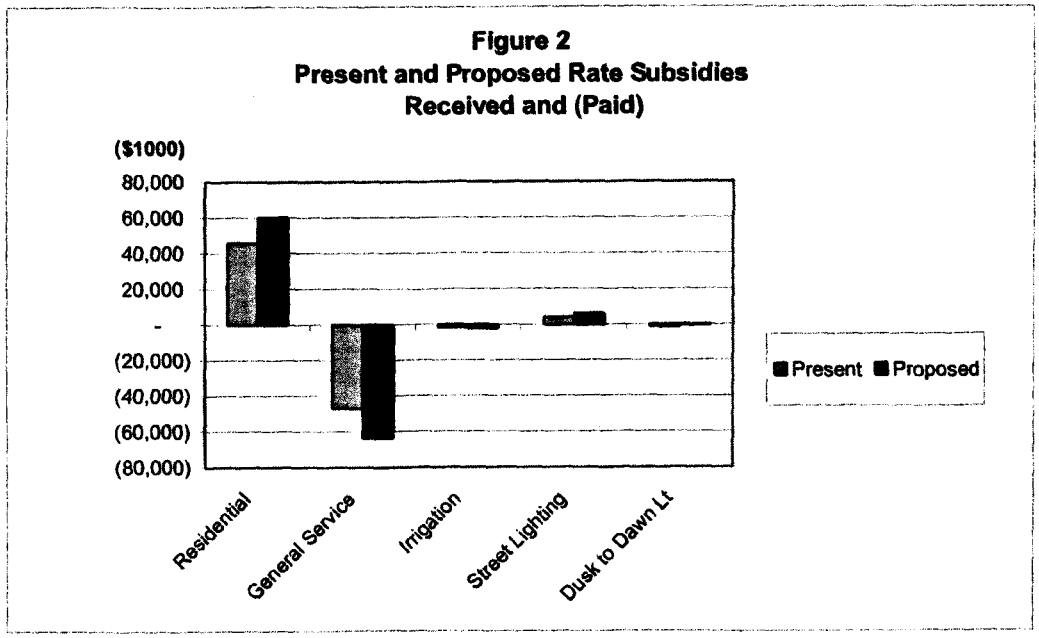
own cost of service study shows that residential customers are currently paying substantially less than cost of service. Table 2 shows the proposed percentage rate increases recommended by APS in this proceeding and the resulting dollar subsidies that will exist at proposed rates. Despite the substantial variation in relative rate of return and the concomitant subsidies being paid by general service customers, APS is recommending that the subsidies paid by general service customers be increased.

TABLE 2
Proposed Increases and Subsidies
Average and Excess Demand Cost of Service Study

Class	Proposed % Increase	Proposed Subsidy
Residential	17.27%	60,190
General Svc	16.74%	(63,713)
E-20 (Church Rate)	20.20%	1,115
E-32 TOU	16.71%	(1,380)
E-30, E-32 (0-20 kW)	18.67%	5,038
E-32 (21-100 kW)	16.58%	(15,599)
E-32 (101-400 kW)	16.22%	(21,513)
E-32 (401+ kW)	15.74%	(30,120)
E-34	16.50%	(2,836)
E-35	18.69%	1,582
Irrigation	12.30%	(2,150)
Street Light	19.41%	6,064
Dusk to Dawn	19.36%	(391)
Total Retail	16.99%	

Figure 2 below shows the present and proposed dollar subsidies being recommended by APS in this case. APS is proposing to increase the subsidies received by

residential customers by close to $15 million, and to increase the subsidies paid by general service customers by an equal amount.



Q. Are you recommending that proposed rates in this case be set at cost of service to eliminate all subsidies?

A. No. I recognize that this would not be realistic, given the impact on residential customers. It would also be inconsistent with the regulatory concept of gradualism. Though this would be an ideal result and one that should be recognized as a longer-term goal in future rate proceedings, I am not recommending the elimination of all subsidies in this proceeding. However, there is no justification for increasing the

disparities, given the existing situation. Some mitigation of the subsidies should be made in this case.

If the cost of service study is used directly to allocate the requested $450 million increase, residential customers would be assigned a $293 million increase (22%), while general service customers would receive a $144 million increase (12%). This is the result that would be obtained if 100% of the current subsidies were eliminated in this proceeding.

At the same time, it is unreasonable to completely ignore the results of the Company's cost of service study (and other cost of service analyses prepared by the Company in response to data requests).

Q. **In light of the impact on residential customers of completely eliminating the subsidies in this proceeding, do you have an alternative recommendation that would recognize the results of the Company's cost of service study in allocating the increase?**

A. Yes. I believe that it is appropriate to make some progress towards eliminating the subsidies contained in present rates in this case. A reasonable and balanced approach would be to reduce class subsidies by 25% as a means of moving towards the objective of setting rates based on cost of service. The analysis presented in

1 Exhibit ___(SJB-2) shows the results of a 25% subsidy reduction in the allocation of
2 the requested $448 million increase. As can be seen in the third "box" in Exhibit
3 ___(SJB-2), eliminating 25% of the subsidy would result in an increase to
4 residential customers of $259.9 million (19.3%), while producing a $180.0 million
5 increase (14.5%) to the general service class. A 25% subsidy reduction criterion for
6 allocating the approved revenue requirement increase in this case would still result
7 in proposed rates that contain substantial subsidies, though these subsidies will be
8 reduced going forward. Subsequent rate cases should be used to further reduce
9 subsidies in future periods.
10
11 **Q. Are you also proposing that this "25% subsidy reduction" methodology be**
12 **extended to include each of the General Service Rate schedules?**
13
14 A. Yes. Baron Exhibit__(SJB-3) contains the results for the individual General Service
15 rate schedules. The total for the General Service rate schedule increases equals the
16 amount for the General Service class shown in Exhibit__(SJB-2).
17
18 Table 3 summarizes the proposed increases for each major rate class and the
19 individual General Service Rate schedules that I am recommending (assuming that
20 the Company received its full rate request). Also shown are the remaining subsidies
21 that will be received and paid, after the 25% reduction at proposed rates.
22

1

TABLE 3
Kroger Proposed Increases and Subsidies
25% Subsidy Reduction

Class	Proposed Increase	Proposed % Increase
Residential	259,938	19.30%
General Svc	180,229	14.53%
E-20 (Church Rate)	660	20.21%
E-32 TOU	1,870	12.12%
E-30, E-32 (0-20 kW)	36,443	20.96%
E-32 (21-100 kW)	43,269	15.83%
E-32 (101-400 kW)	39,834	13.62%
E-32 (401+ kW)	35,168	11.46%
E-34	10,918	12.73%
E-35	12,068	13.53%
Irrigation	2,148	8.46%
Street Light	4,428	25.49%
Dusk to Dawn	1,451	19.36%
Total Retail	448,193	16.99%

2

3

4 **Q. Does your recommended methodology reflect any adjustments to mitigate**
5 **the impact on specific rate classes?**

6

7 A. Yes. The increases recommended in Exhibits__(SJB-3) and (SJB-3), as well as
8 Table 3 reflect a "capping" of the increase to the Street Light at 1.5 times the
9 system average percentage increase and setting the increase for the Dusk to Dawn
10 rate class at the level proposed by the Company, which already reflected a

1 substantial decrease in the subsidies paid by this rate class.[3] Finally, within the
2 General Service rate class, I have adopted the Company's proposed increase for
3 "Rate E-20 Church Rate."
4
5 **Q. Have you developed any alternative recommendation for the allocation of the**
6 **revenue increase, in the event that the Commission does not elect to reduce**
7 **intra-class subsidies by 25%, as you have proposed?**
8
9 A. Yes. My alternative recommendation is to adopt the Company's proposed intra-
10 class revenue increase allocation (rate spread), and apply a 25% subsidy reduction
11 allocation only within the General Service class. Effectively, under this
12 alternative recommendation, the increases to each major rate class would be the
13 APS proposed increases shown in my Table 2 (e.g., General Service as a whole
14 would receive an increase of 16.74%).
15 However, within the General Service rate class, the Company's proposed
16 increases to individual rate schedules would be adjusted so that dollar subsidies,
17 relative to the entire General Service class, are reduced by 25%.
18

[3] Without this adjustment, the Dusk to Dawn lighting class would have received a very large increase, even though it is paying subsidies at present rates. This occurs because of the relationship between revenues and rate base for this class (the ratio of revenues to rate base for this class is very low, compared to the retail average relationship). APS has proposed a substantial elimination of the current subsidy paid by this class.

Baron Exhibit__(SJB-4) shows the results on this analysis, while Table 4 presents the increases to each General Service rate. As can be seen, the overall General Service increase remains at the same level as proposed by APS.[4]

TABLE 4
Kroger Proposed Increases and Subsidies
General Service Class Only - 25% Subsidy Reduction

Class	Proposed Increase	Proposed % Increase
General Svc	207,600	16.74%
E-20 (Church Rate)	660	20.20%
E-32 TOU	2,169	14.06%
E-30, E-32 (0-20 kW)	41,586	23.92%
E-32 (21-100 kW)	50,078	18.32%
E-32 (101-400 kW)	46,172	15.79%
E-32 (401+ kW)	40,986	13.35%
E-34	12,456	14.53%
E-35	13,493	15.12%

Q. What is your recommendation for allocating the revenue increase if the Company is authorized a lower increase than it is requesting in this case?

A. The recommended dollar increases to each rate class shown in exhibit__(SJB-2) should be reduced on an equal percentage basis.

[4] I have also made no change to the Company's proposed increase to rate schedule E-20 (Church Rate).

III. RATE E-32 RATE DESIGN

Q. Have you reviewed APS' proposal to disaggregate Rate E-32 into four separate rates based on kW demand levels?

A. Yes. I have reviewed the Company's proposal and support the proposed separation in four new rates, delineated by kW demand levels. As noted in the testimony of Company witness DeLizio on page 28 of his testimony, the disaggregated rates provide a better matching of cost of service and rate design for General Service customers.

Q. Mr. Delizio states on page 29 of his testimony that the disaggregated E-32 rates were developed to moderate the impact of the redesign. Do you agree with the Company's proposal on this issue?

A. Though I agree that the disaggregated E-32 rate design should consider the impact on the individual new rates, as I discussed in the prior section of my testimony, the mitigation proposed by the Company in its design does not adequately reduce intra-General Service class subsidies. Such subsidies should be reduced by 25% in this case, as I discussed previously.

Q. Does that complete your testimony?

1

2 A. Yes.

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THEREON, TO APPROVE RATE SCHEDULES	)	
DESIGNED TO DEVELOP SUCH RETURN	)	

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

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10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

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1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

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4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

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6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

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			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
09/06	E-01345A- 05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No.	PA	West Penn Power	West Penn Power Co.	Default Service Plan issues.

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	P-00072342		Industrial Intervenors		
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
11/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge

BEFORE THE

ARIZONA CORPORATION COMMISSION

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	)	**Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	)	
AND REASONABLE RATE OF RETURN	)	
THEREON, TO APPROVE RATE SCHEDULES	)	
DESIGNED TO DEVELOP SUCH RETURN	)	

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessar y to Reduce Class S ubsidies by 25%
Adjusted to Cap Lighting at 1.5x System Average

	Total ACC Jurisdiction	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
COST OF SERVICE AT PRESENT RATES						
Revenues from Base Rates	2,637,447	1,347,035	1,240,168	25,376	17,372	7,496
Revenues from Surcharges	-	-	-	-	-	-
Other Electric Revenues	94,461	47,608	42,643	867	3,063	280
Total Revenue (Existing Rates)	2,731,908	1,394,643	1,282,811	26,243	20,435	7,776
Operating Expenses before Income Taxes	2,500,562	1,310,086	1,140,256	23,495	21,437	5,288
Income Taxes	28,234	368	27,578	666	(981)	603
Net Operating Income	203,112	84,189	114,977	2,082	(21)	1,885
Rate Base	5,359,964	2,954,460	2,282,488	30,142	64,347	28,527
Rate of Return	3.79%	2.85%	5.04%	6.91%	-0.03%	6.61%
Rate of Return Index	1.000	0.752	1.329	1.823	(0.009)	1.744
Subsidy at Present Rate of Return	(0)	45,792	(46,972)	(1,550)	4,056	(1,326)
Percentage Increase		3.28%	-3.66%	-5.91%	19.85%	-17.05%
Increase to Equalized Proposed Rate of Return	448,194	292,840	143,887	971	9,436	1,060
Percentage Increase	16.99%	21.74%	11.60%	3.83%	54.32%	14.13%
APS Proposed Percentage Increases	16.99%	17.27%	16.74%	12.30%	19.41%	19.36%
Proposed Class Rate Increase	448,194	232,850	207,600	3,121	3,372	1,451
Less: Incremental Income Taxes	(176,409)	(91,571)	(81,711)	(1,228)	(1,327)	(571)
Net Income @ proposed rates	474,897	225,268	240,866	3,975	2,024	2,765
Rate of Return @ proposed rates	8.86%	7.62%	10.55%	13.19%	3.15%	9.69%
Rate of Return Index	1.000	0.861	1.191	1.488	0.355	1.094
Subsidy at Company Proposed Rates	0	60,190	(63,713)	(2,150)	6,064	(391)
Kroger Proposed Subsidy (75% of Present)	(0)	34,344	(35,229)	(1,162)	3,042	(994)
Adjustment	-	1,441	1,113	15	(1,966)	(603)
Required Rate Increase	448,194	259,938	180,229	2,148	4,428	1,451
Percentage Increase	16.99%	19.30%	14.53%	8.46%	25.49%	19.36%
Net Income with Kroger Subsidy Reduction	474,897	241,815	224,268	3,384	2,664	2,765
Rate of Return	8.86%	8.18%	9.83%	11.23%	4.14%	9.69%
Rate of Return Index		0.924	1.109	1.267	0.467	1.094
Pro Forma PSA Impact	(169,977)	(79,859)	(87,217)	(1,989)	(758)	(154)
Net Increase	278,217	180,079	93,012	159	3,670	1,297
Net Percentage Increase	10.55%	13.37%	7.50%	0.63%	21.13%	17.30%

BEFORE THE

ARIZONA CORPORATION COMMISSION

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	**) Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	**)**
AND REASONABLE RATE OF RETURN	**)**
THEREON, TO APPROVE RATE SCHEDULES	**)**
DESIGNED TO DEVELOP SUCH RETURN	**)**

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessary to Reduce Class Subsidies by 25%

	Total ACC Jurisdiction	General Service	E-20 (Church Rate)	E-32 TOU	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
COST OF SERVICE AT PRESENT RATES										
Revenues from Base Rates	2,637,447	1,240,169	3,267	15,429	173,838	273,358	292,377	306,941	85,742	89,217
Revenues from Surcharges	-	-	-	-	-	-	-	-	-	-
Other Electric Revenues	94,461	42,643	140	570	5,502	8,912	10,049	10,722	3,195	3,553
Total Revenue (Existing Rates)	2,731,908	1,282,812	3,408	15,999	179,339	282,270	302,426	317,663	88,937	92,770
Operating Expenses before Income Taxes	2,500,562	1,140,256	3,718	14,113	162,580	241,372	262,770	276,075	84,073	95,575
Income Taxes	28,234	27,578	(219)	417	1,704	8,865	8,767	9,846	422	(2,214)
Net Operating Income	203,112	114,978	(91)	1,469	15,076	32,042	30,889	31,741	4,443	(591)
Rate Base	5,359,984	2,282,486	*11,122*	*24,772*	426,821	565,107	525,980	482,809	127,572	118,306
Rate of Return	3.79%	5.04%	-0.82%	5.93%	3.53%	5.67%	5.87%	6.57%	3.48%	-0.50%
Rate of Return Index	1.000	1.329	(0.215)	1.564	0.932	1.496	1.550	1.735	0.919	(0.132)
Subsidy at Present Rate of Return	-	(46,973)	845	(874)	1,811	(17,526)	(18,069)	(22,173)	846	8,368
Percentage Increase		-3.79%	25.85%	-5.66%	1.04%	-6.41%	-6.18%	-7.22%	0.75%	9.38%
Increase to Equalized Proposed Rate of Return	448,194	143,886	1,775	1,196	37,501	29,727	25,913	18,199	11,313	18,261
Percentage Increase	16.99%	11.60%	54.32%	7.76%	21.57%	10.87%	8.86%	5.93%	13.19%	20.47%
APS Proposed Percentage Increases	16.99%	16.74%	20.20%	16.71%	18.67%	16.58%	16.22%	15.74%	16.50%	18.69%
Proposed Class Rate Increase	**448,194**	**207,660**	**660**	**2,576**	**32,463**	**45,328**	**47,426**	**48,319**	**14,149**	**18,679**
Less: Incremental Income Taxes	(176,409)	(81,711)	(260)	(1,015)	(12,777)	(17,840)	(18,667)	(19,018)	(5,569)	(6,565)
Net Income @ proposed rates	474,897	240,866	309	3,032	34,761	59,528	59,648	61,042	13,023	9,523
Rate of Return @ proposed rates	8.86%	10.55%	2.78%	12.24%	8.14%	10.53%	11.34%	12.64%	10.21%	8.05%
Rate of Return Index	1.000	1.191	0.314	1.381	0.919	1.189	1.280	1.427	1.152	0.909
Subsidy at Company Proposed Rates	-	(83,714)	1,115	(1,380)	5,038	(15,599)	(21,513)	(30,120)	(2,836)	1,582
Kroger Proposed Subsidy (75% of Present)	-	(35,230)	634	(655)	1,358	(13,145)	(13,552)	(16,630)	484	6,276
Adjustment for E-20		-	481	(5)	(90)	*(120)*	*(111)*	(102)	(27)	(25)
Adjustment for "1.5" Times Rate Cap		1,113	-	12	209	277	258	237	63	58
Required Rate Increase	448,194	180,229	660	1,870	36,443	43,269	39,834	35,168	10,918	12,068
Kroger Percentage Increase	**16.99%**	**14.53%**	**20.21%**	**12.12%**	**20.96%**	**15.83%**	**13.62%**	**11.46%**	**12.73%**	**13.53%**
Net Income with Kroger Subsidy Reduction	474,897	224,268	310	2,603	37,175	58,260	55,044	53,087	11,064	8,727
Rate of Return	*8.86%*	9.83%	2.78%	10.51%	8.71%	10.31%	10.47%	10.99%	8.67%	5.69%
Rate of Return Index		1.109	0.314	1.186	0.983	1.164	1.181	1.241	0.979	0.642
Pro Forma PSA Impact	(169,977)	(87,217)	(203)	(1,246)	(8,490)	(16,122)	(20,433)	(23,959)	(7,605)	(9,160)
Net Increase	278,217	93,012	457	624	27,953	27,147	19,401	11,210	3,313	2,908
Net Percentage Increase	**10.56%**	**7.50%**	**13.90%**	**4.05%**	**16.08%**	**9.93%**	**6.64%**	**3.65%**	**3.86%**	**3.26%**

BEFORE THE

ARIZONA CORPORATION COMMISSION

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	**) Docket No. E-01345A-08-0172**
FOR RATEMAKING PURPOSES, TO FIX A JUST	**)**
AND REASONABLE RATE OF RETURN	**)**
THEREON, TO APPROVE RATE SCHEDULES	**)**
DESIGNED TO DEVELOP SUCH RETURN	**)**

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessary to Reduce General Service Class Only
Intra-Class Subsidies by 25%

	Total ACC Jurisdiction	General Service	E-20 (Church Rate)	E-32 TOU	E-30, E-32 (0 - 20 kW)	E-32 (21 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
COST OF SERVICE AT PRESENT RATES										
Revenues from Base Rates	2,637,447	1,240,169	3,267	15,429	173,838	273,356	292,377	306,941	85,742	89,217
Revenues from Surcharges	-	-	-	-	-	-	-	-	-	-
Other Electric Revenues	94,461	42,643	140	570	5,502	8,912	10,049	10,722	3,195	3,553
Total Revenue (Existing Rates)	2,731,908	1,282,812	3,406	15,999	179,339	282,270	302,426	317,663	88,937	92,770
Operating Expenses before Income Taxes	2,500,562	1,140,256	3,718	14,113	162,560	241,372	262,770	276,075	84,073	95,575
Income Taxes	28,234	27,578	(219)	417	1,704	8,855	8,767	9,846	422	(2,214)
Net Operating Income	203,112	114,978	(91)	1,468	15,076	32,042	30,889	31,741	4,443	(591)
Rate Base	5,359,964	2,282,488	11,122	24,772	426,821	565,107	525,980	482,809	127,572	118,306
Rate of Return	3.79%	5.04%	-0.82%	5.93%	3.53%	5.67%	5.87%	6.57%	3.48%	-0.50%
Rate of Return Index	1.000	1.329	(0.215)	1.564	0.932	1.496	1.550	1.735	0.919	(0.132)
Subsidy at Present Rate of Return	-	(0)	1,074	(384)	10,595	(5,897)	(7,245)	(12,237)	3,271	10,803
Percentage Increase		0.00%	32.86%	-2.36%	6.09%	-2.16%	-2.48%	-3.99%	3.82%	12.11%
Increase to Equalized Proposed Rate of Return	448,194	143,886	1,775	1,198	37,501	29,727	25,913	18,199	11,313	18,261
Percentage Increase	16.99%	11.60%	54.32%	7.76%	21.57%	10.87%	8.86%	5.93%	13.19%	20.47%
APS Proposed Percentage Increases	**16.99%**	**16.74%**	**20.20%**	**16.71%**	**16.67%**	**16.58%**	**16.22%**	**15.74%**	**16.60%**	**18.89%**
Proposed Class Rate Increase	448,194	207,600	660	2,578	32,463	45,326	47,428	48,319	14,149	16,679
Less: Incremental Income Taxes	(176,409)	(81,711)	(260)	(1,015)	(12,777)	(17,840)	(18,667)	(19,018)	(5,569)	(6,565)
Net Income @ proposed rates	474,897	240,866	309	3,032	34,761	59,528	59,648	61,042	13,023	9,523
Rate of Return @ proposed rates	8.86%	10.55%	2.78%	12.24%	8.14%	10.53%	11.34%	12.64%	10.21%	8.05%
Rate of Return Index	1.000	1.191	0.314	1.381	0.919	1.189	1.280	1.427	1.152	0.909
Subsidy at Company Proposed Rates	-	0	1,425	(689)	16,953	176	(6,631)	(16,643)	725	4,884
Kroger Proposed Subsidy (75% of Present)	-	(0)	805	(273)	7,946	(4,422)	(5,434)	(9,178)	2,453	8,102
Adjustment for E-20		(0)	(620)	7	116	154	144	132	35	32
Required Rate Increase	448,194	207,600	660	2,169	41,586	50,078	46,172	40,986	12,456	13,493
Kroger Percentage Increase	**16.99%**	**16.74%**	**20.20%**	**14.06%**	**23.92%**	**18.32%**	**15.79%**	**13.35%**	**14.53%**	**15.12%**
Net Income with Kroger Subsidy Reduction	474,897	240,866	309	2,784	40,294	62,410	58,888	56,596	11,998	7,591
Rate of Return	8.86%	10.55%	2.78%	11.24%	9.44%	11.04%	11.20%	11.72%	9.40%	6.42%
Rate of Return Index		1.191	0.314	1.268	1.065	1.246	1.264	1.323	1.061	0.724
Pro Forma PSA Impact	(169,977)	(87,217)	(203)	(1,246)	(8,490)	(16,122)	(20,433)	(23,958)	(7,605)	(9,160)
Net Increase	278,217	120,383	457	923	33,096	33,956	25,739	17,028	4,851	4,333
Net Percentage Increase	**10.55%**	**9.71%**	**13.99%**	**5.96%**	**19.04%**	**12.42%**	**8.80%**	**5.55%**	**5.66%**	**4.66%**

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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

EXHIBIT
Mesquite-1
ADMITTED

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-08-0172

DIRECT TESTIMONY OF LEESA NAYUDU ON BEHALF OF

MESQUITE POWER, L.L.C., SOUTHWESTERN POWER GROUP II, L.L.C.,

AND BOWIE POWER STATION, L.L.C. ("COLLECTIVELY "MESQUITE GROUP")

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DIRECT TESTIMONY
OF
LEESA NAYUDU

Q.1 Please state your name and business affiliation.

A.1 My name is Leesa Nayudu, and I am Director of Origination with Sempra Generation, which owns Mesquite Power, L.L.C. ("Mesquite").

Q.2 On whose behalf are you providing this testimony?

A.2 I am testifying on behalf of Mesquite, Southwestern Power Group II, L.L.C. ("SWPG") and Bowie Power Station, L.L.C. ("Bowie") (collectively "Mesquite Group"). The Mesquite Group was granted intervention in this proceeding by means of a Procedural Order issued on April 25, 2008. Thereafter, we were active participants throughout the settlement negotiations which resulted in the June 12, 2009 Settlement Agreement that has been filed with the Commission.

Q.3 Have the members of the Mesquite Group previously participated in proceedings before the Commission in which Arizona Public Service Company ("APS") was either the Applicant or a major participant?

A.3 Yes, we have actually participated in a number of proceedings of that nature before the Commission. Included among those proceedings were (i) the Track "A proceeding, (ii) the Track "B" proceeding, (iii) APS' $500 million financing proceeding, (iv) APS' acquisition of the Sundance Generating assets, (v) APS' 2003 rate case, (vi) APS' 2005 Power Supply Adjuster/Surcharge proceeding, (vii) APS' request for an emergency interim rate increase, (viii) APS' 2005 rate case, (ix) APS' Yuma RFP proceeding, (x) the APS "self-build" moratorium 40-252 proceeding and (xi) this rate proceeding.

Q.4 What is the purpose of your testimony at this time?

A.4 Each of the companies comprising the Mesquite Group has signed the Settlement Agreement. Pursuant to the Procedural Order issued by the Chief Administrative Law Judge Lyn Farmer on May 3, 2009, the Mesquite Group is providing this Direct Testimony in support of the Settlement Agreement as it relates to their collective interests.

Q.5 What is the nature of those "collective interests" as they pertain to this proceeding?

A.5 The members of the Mesquite Group participate as actual and prospective vendors in the competitive wholesale power supply market in Arizona. Originally, their participation relied upon conventional sources of electric generation, such as natural gas-fired combined cycle electric generation facilities. Examples of these are the 1,250 MW Mesquite generation facility, which has been in service since 2003; and, the 1,000 MW Bowie power station, which is currently under construction. In more recent years, the members of the Mesquite Group (or affiliated entities) have begun to include generation projects which utilize renewable technology in their respective business plans and marketing activities. In addition, SWPG is serving as Project Manager for the proposed Sun Zia renewables energy transmission project, which entails 460 miles of 500 kV double-circuit electric transmission facilities in Arizona and New Mexico.

Q.6 Have one or more members of the Mesquite Group participated in competitive power procurements conducted by APS?

A.6 Yes. It is my understanding that at various times since 2003 one or more members of the Mesquite Group (or affiliated entities) have participated in Request(s) For Proposal ("RFP") and other forms of competitive procurement conducted by APS, which have involved both conventional and renewable sources of generation.

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Q.7 Does the Mesquite Group believe that the Settlement Agreement adequately addresses its "collective interests"?

A.7 Yes, for reasons I will discuss in my testimony.

Q.8 Please identify those areas of the Settlement Agreement which you will address in your testimony.

A.8 I will be discussing portions of Sections I (Recitals), II (Rate Case Stability Provisions), VIII (Equity Infusions), XIII (Periodic Evaluation) and XV (Renewable Energy).

Q.9 Please begin your discussion with Section I (Recitals).

A.9 Typically, Recitals are used to provide background and context for the document in question. In this instance, the language of Paragraphs 1.4, 1.7 and 1.15 is very important to the Mesquite Group because it expressly recognizes that APS' credit ratings directly impact both (i) its ability to raise capital on favorable terms for capital expenditures, and (ii) its ability to obtain credit on favorable terms from vendors as a purchaser in the competitive wholesale electric market. In turn, this latter recognition is reflective of the Commission's previous policy determination that the ongoing existence of a viable competitive wholesale electric market in Arizona is in the best interest of both Arizona's electric utilities and their ratepayers. Given APS' status as the largest electric utility in the state of Arizona, and its role as a major purchaser in the competitive wholesale electric market, its financial stability and resulting creditworthiness is essential to the successful functioning and viability of that market.

As the Commission is aware, sometimes the most appropriate power resource choice for an electric utility is a long-term Purchased Power Agreement or the acquisition of a developer-build project. Other times, the most appropriate choice may be a self-build decision by the utility. Paragraphs 1.4, 1.7 and 1.15 of the Settlement Agreement recognize the importance of providing and preserving this operational flexibility for APS as a stated objective of the Settlement Agreement; and, that recognition enables the

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Mesquite Group to support the Settlement Agreement. Before concluding my remarks on this subject, I would note that Paragraph 3.4 of the Settlement Agreement also expressly acknowledges the importance of such operational flexibility.

Q.10 Please comment on Section II of the Settlement Agreement.

A.10 Section II is entitled "Rate Case Stability Provisions," and that is precisely the intended end result of the provisions contained in that portion of the Settlement Agreement. Recent years have been characterized by a pattern of back-to-back APS rate or rate-related proceedings before the Commission. In addition to the time and expense these proceedings have entailed for all concerned, including the Mesquite Group, this seemingly unbroken chain of proceedings has created uncertainty as to APS' financial circumstances and stability for its ratepayers, its investors, its vendors and lenders, and the financial community as a whole.

Against that background, the provisions of Section II are designed to provide a measure of predictability as to the timing of, and appropriate intervals between, APS' filing of rate cases for the next few years. In addition, in combination with the provisions of other sections in the Settlement Agreement, the provisions of Section II are designed to provide APS and the aforesaid stakeholders with a period of revenue stability during the next few years. The Mesquite Group believes that such stability clearly is in the best interests of all concerned.

Q.11 Please discuss why the Mesquite Group believes Section VIII is an important part of the Settlement Agreement.

A.11 In addition to APS' agreement to complete infusions of at least $700 million of additional equity between June 1, 2009 and December 31, 2014, this section of the Settlement Agreement contains several additional provisions which the Mesquite Group believes will contribute to the financial stability and strength of APS during the next few years.

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More specifically, Paragraph 8.2 contains an express acknowledgement by APS that the Company has a responsibility to exert its "best efforts" to both (i) maintain investment grade financial ratios and a balanced capital structure, and (ii) work to improve its existing ratings with the financial rating agencies. Each of these, in turn, will contribute towards improving the financial stability and creditworthiness of the Company.

In that regard, Paragraph 8.4 provides that APS will prepare and submit to the Commission and the signatory parties to the Settlement Agreement a "plan detailing steps it [APS] intends to take to maintain and improve its financial ratings." The Mesquite Group believes that this is a very important provision, because it will provide the signatory parties with an opportunity to file comments, and the Commission an opportunity to act, in advance of APS beginning to substantially implement its "plan," in the event that the Commission and/or a signatory party or parties believe(s) that APS' "plan" is poorly conceived or lacking in that detail to be desired. In the past, both the Commission and intervenors in APS' interim and permanent rate proceedings have found themselves in a reactive posture, where the options for ameliorative action were narrowly circumscribed by then existing circumstances.

Q.12 In the opinion of the Mesquite Group, is there a relationship between APS' responsibilities under Section VIII of the Settlement Agreement, and the $30 million annual average reduction in expenditures by APS provided for in Section V of the Settlement Agreement?

A.12 Yes. The Mesquite Group believes it is incumbent upon APS to exert its best efforts to reduce annual expenses, consistent with the ongoing provision of adequate and reliable electric service at reasonable costs, as a part of the company's concerted effort to stabilize its financial performance and improve its credit metrics. The $30 million average annual reduction in expenses provided for in the Settlement Agreement, and which has been agreed to by APS, is consistent with our philosophy in that regard. It also

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is our perception that APS intends to meet, if not exceed, that annual target as well as the five (5)-year aggregate target of $150 million. Achieving these targets should materially assist APS in discharging its responsibilities under Paragraph 8.2.

Q.13 Please comment on why the Mesquite Group believes that Section XIII is an important part of the Settlement Agreement.

A.13 Both the language and tone of Paragraph 13.1 establish a conceptual framework which the Mesquite Group believes is very important. That paragraph provides as follows:

> "13.1 The Signatories agree that the Company should exert its best efforts on an ongoing basis to maximize opportunities for financial soundness provided by virtue of this Agreement; and that such efforts by the Company should be subject to periodic evaluation through the use of the Performance Measurements and Reporting Requirements." [emphasis added]

As I have previously indicated, the Mesquite Group executed and supports the Settlement Agreement, because it believes that the provisions of the same provide APS with genuine opportunities to stabilize and improve its financial metrics and creditworthiness to the benefit of its ratepayers, its investors, its vendors and lenders and the financial community as a whole; and, the language of Paragraph 13.1 contains an express recognition to that effect. At the same time, the Mesquite Group believes that APS should be required to periodically report upon the activities it has undertaken to maximize those opportunities, and the results of those activities. Paragraph 13.1 and the provisions of Section XIII as a whole provide for such periodic reporting and evaluation, and thus warrant the Mesquite Group's support.

In that regard, and in addition to the general Financial Reporting provided for under Section XIII (B) (i) through (xii) of the Settlement Agreement, the Mesquite Group is also quite interested in the information to be reported under Paragraph 13.4 (b) (xii), which requires APS to periodically report

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"xii. Information regarding the Company's level of major capital expenditures, and its consideration of available alternatives in connection with such capital expenditures for generation facilities." [emphasis added]

The Mesquite Group believes that the periodic reporting of information of the nature contemplated by this provision should enable the Commission and other interested persons (such as the Mesquite Group) to determine (i) whether APS is giving appropriate consideration to power resource alternatives and arrangements available from the competitive market in connection with decisions APS makes to satisfy its power resource requirements; and, (ii) whether APS has complied with the Commission's Recommended Best Practices for Procurement, the Commission's RES regulations, and APS' Renewable Energy Competitive Procurement Procedure to the extent applicable.

Q.14 Please discuss those portions of Section XV of the Settlement Agreement which are of direct interest to the Mesquite Group.

A.14 There are two (2), namely, Paragraph 15.1 and Paragraph 15.3. In that regard, as indicated earlier in my testimony, in recent years the members of the Mesquite Group have begun to include generation projects which utilize renewable technology in their respective business plans and marketing activities.

Paragraph 15.1 provides that APS will exert its "best efforts" to significantly acquire additional new renewable energy resources with in-service dates by or before December 31, 2015. It is quite conceivable that some of these resources may offer potential business opportunities to one (1) or more members of the Mesquite Group (or affiliated entities).

Paragraph 15.3 expressly provides that APS shall file a "plan" with the Commission for a utility scale photovoltaic generation project (with the indicated commencement of construction date) within 120 days from a Commission decision approving the Settlement Agreement. In addition, this paragraph expressly requires that APS "shall initiate a competitive procurement" as the means for identifying and selecting the project which will be the subject of APS' "plan." The competitive procurement must

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comply with APS' Renewable Energy Competitive Procurement Procedure to which I previously referred; and, pursuant to Paragraph 15.3, any signatory to the Settlement Agreement may file comments on APS' "plan." Both the contemplated timing of this particular project, and the use of a "competitive procurement" project selection process are matters in which the members of the Mesquite Group (or affiliated entities) have an interest.

Q.15 Does this complete your discussion of those areas of the Settlement Agreement that you wished to address in your pre-filed Direct Testimony?

A.15 Yes, it does.

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ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-08-0172

DIRECT TESTIMONY
IN SUPPORT OF SETTLEMENT AGREEMENT

OF

JODI A. JERICH, DIRECTOR

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 1, 2009

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INTRODUCTION

Q. **Please state your name, occupation and business address for the record.**

A. My name is Jodi Jerich. I am the Director of the Arizona Residential Utility Consumer Office (RUCO). My business address is 1110 W. Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Governor Brewer appointed me to serve as the Director of the RUCO in February 2009. The State Senate found my qualifications met the statutory requirements found in Arizona Revised Statutes §40-462 and confirmed my appointment. As Director, I was the main negotiator for RUCO during the settlement process.

From 2003 through 2005, I was employed at the Arizona Corporation Commission as the Policy Advisor to Corporation Commissioner Mike Gleason. In that role, I advised the Commissioner on matters coming before the Commission. I was actively involved in the utility policy-making decisions of that Commissioner's office. During my tenure at the Commission, I advised the Commissioner on the 2005 APS rate case settlement that resulted in Decision No. 67744. Many of the issues in that

matter are once again before the Commission in the pending APS rate case and corresponding Settlement Agreement.

Except for the time I was employed by the Commission, from 1997 through 2008, I was employed at the Arizona House of Representatives. I held several positions during my tenure, eventually becoming Chief of Staff and Counsel to the Majority Caucus. Relevant to the question at hand, I advised Legislators on matters involving water, energy, Commission jurisdiction and utility security.

In 2006, when Governor Janet Napolitano appointed Barry Wong to fill the Commission seat vacated by Commissioner Marc Spitzer's appointment to the Federal Energy Regulatory Commission (FERC), I took a leave of absence from the Legislature for a short time in order to assist Commissioner Wong establish his office.

Finally, I am a Phi Beta Kappa graduate of Indiana University. I also have a law degree from Indiana University and am a member of the Arizona and Tennessee bars.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain RUCO's support of the Settlement Agreement.

THE SETTLEMENT PROCESS

Q. Was the negotiation process that resulted in the Settlement Agreement a proper and fair process?

A. Yes. The Settlement Agreement is the result of numerous hours of negotiation and a willingness among the parties to compromise. The negotiations were conducted in a fair and reasonable way that allowed each party the opportunity to participate. All intervenors had an opportunity to participate in every step of the negotiation and notice for each scheduled meeting was sent to all parties electronically. Persons were able to participate via teleconference if necessary. In total, the parties met 21 times from January 30, 2009 to June 11, 2009 before finalizing the Settlement Agreement. Each participant was able to engage in meaningful negotiations. All parties were allowed to express their positions fully.

Twenty entities signed the Settlement Agreement. These entities represent a wide range of interests from environmental advocate groups, agricultural interests, governmental entities, business and industrial interests, low income advocates, union representatives, Commission Staff and RUCO.

Q. Why is a negotiated settlement process an appropriate way to resolve this matter?

A. The Settlement Agreement results in clarity and regulatory certainty, without the risk of protracted litigation and appeals. The Settlement Agreement guarantees that RUCO will get what it believes is most important – a well thought out plan which should improve the Company's financial metrics over the short and long term, while at the same time keeping rates as low and stable as possible while providing benefits to ratepayers. Settlement negotiations began only after each party had the opportunity to analyze the Company's Application, file its Direct Testimony and read the Direct Testimony of other Intervenors. Of course, the Settlement Agreement in no way eliminates the Commission's constitutional right and duty to review this matter and to make its own determination whether the Settlement is truly balanced and the rates are just and reasonable.

Q. Please summarize your testimony.

A. The Settlement Agreement reflects an outcome that is fair to both the consumer and the Company. Furthermore, this is a comprehensive Settlement Agreement. Its terms settle a wide range of issues that were of significant interest to several of the Intervenors. RUCO supports this Agreement in its entirety because it contains numerous benefits to the

consumer as well as putting the Company on a true path to financial health.

SETTLEMENT PROVISIONS

Q. In summary, what are the main provisions of the Settlement?

A. The Settlement Agreement is a comprehensive document that resolves numerous and divergent issues. As detailed below, the Settlement Agreement provides a $196.3 million non-fuel base rate increase for the Company and $11.2 million associated with establishing new base fuel levels. The $196.3 million increase includes the $65 million already authorized by the Commission in interim rates. The Settlement Agreement also freezes rates for at least 2 ½ years (no earlier than July 1, 2012) and restricts APS from filing future general rate cases until certain dates listed in the Settlement Agreement. The Settlement Agreement also establishes a five year "roadmap" for the Company to regain its financial health. It must reduce its expenses by $150 million, make equity infusions of $700 million, strive to reduce its total debt from 57% to 52%, achieve specified performance measures, limit its executive cash incentive compensation in certain situations, meet identified energy efficiency goals and expand its renewable energy commitment so that 10% of its retail sales are from renewable energy by 2015. Furthermore, the Settlement Agreement addresses the needs of low income ratepayers as well as issues specific to large commercial and industrial users.

Q: In summary, what are the benefits to the residential consumer?

A. The benefits to the residential consumer are:

- Rates frozen for approximately 2 ½ years (no new rates before July 1, 2012).
- Accelerated reset of PSA to offset a portion of the rate increase.
- Maintain 90/10 sharing of PSA.
- APS will strive to achieve a capital structure with no more than 52% total debt by December 31, 2012.
- Equity infusions of $700 million which are designed to improve APS' financial metrics by strengthening APS' credit rating and reducing APS' future debt costs.
- $150 million reduction of APS expenses over the next five years forcing APS to operate more efficiently.
- Restrictions on executive cash incentive compensation.
- Periodic evaluation of APS through the use of Performance Measures with a meaningful consequence for failure to meet these Measures.
- Increased transparency in APS operations through annual and quarterly reporting on its financial health, credit ratings, earned ROE, FFO/debt ratio, management expenses, O&M expenses and dividend payout ratio.

- Benchmarking study comparing APS to other similarly situated utilities across the nation.
- Revenue spread agreement that requires all rate schedules to absorb equal amounts of the total rate increase even though the cost of service studies indicate the residential class's increase should be higher than the increase for commercial or industrial classes.
- Renewable energy projects at schools that serve to reduce school utility bills allowing schools to shift funds from utility bills into the classroom, or possibly resulting in lower property taxes.
- Energy efficiency program establishing efficiency goals through 2012, a new customer financing plan to encourage participation, and a prohibition to seek unrecovered fixed costs until APS' next general rate case.
- Time of Use, super peak and critical peak pricing demand response programs.
- Corresponding decreases to the PSA and SBC (Systems Benefits Charge) upon the granting of the Palo Verde Life Extension.
- More timely recovery of DSMAC program costs to eliminate interest expense paid by ratepayers under the delayed DSMAC recovery program.

Q. In summary, what are the benefits to the Company?

A. The benefits to the Company are:

- Non-fuel rate increase of $196.3 million (This *includes* the $65 million interim rate increase previously approved in Decision No. 70667.).[1]
- A roadmap to better financial health that should improve APS' credit ratings, make APS more attractive to investors, allow APS to borrow money on more favorable terms and stop the cycle of constant rate case litigation.
- A clear signal to investors and Wall Street that, in the Plan Term set forth in the Settlement Agreement, APS has a defined path toward reduced expenses, a meaningful rate of return, increased equity and a plan for renewable energy projects.
- Continuation of the PSA.
- An authorized return on equity of 11.0%.
- Adoption of APS' proposed depreciation rates.
- Adjustment of depreciation rates for Palo Verde License Extension.
- Deferral of a portion of APS pension and OPEB costs up to $42.5 million.
- Ability to treat Schedule 3 proceeds as revenue.
- Tiered incentives to meet energy efficiency goals.

[1] The Settlement Agreement also increases the amount of fuel costs recovered in base rates, shifting these revenues currently recovered through the PSA. Since the PSA has a 90/10 sharing mechanism that is not recognized when fuel costs are recovered in base rates, an additional $11.2 million is retained by the Company. This is the amount that would have gone to the ratepayers had those fuel costs been recovered through the PSA.

- More timely recovery of DSMAC program costs.
- Recovery of capital carrying costs for renewable energy projects to encourage utility-owned renewable energy generation instead of merely purchasing renewable energy from other – possibly out of state – sources (this also serves to encourage least cost renewable resources for the benefit of the customer).
- A commitment of a good faith effort to process future rate cases within 12 months of a sufficiency finding.

PUBLIC INTEREST

Q. How is the public interest satisfied by the Settlement Agreement?

A. At the most fundamental level, the settlement satisfies the public interest from RUCO's perspective in that it provides a framework that should improve APS' financial metrics and credit ratings. As APS noted, out of a total of 139 rated utilities, only five companies are rated lower than APS. (Brant Direct, p. 39)

RUCO is deeply concerned with APS' continuous marginal credit rating and constant claims that a downgrade to "junk bond" status is imminent. This strategy has been successful in the past to receive rate and other forms of relief from the Commission based on these claims. Yet, despite the relief, APS' financial metrics have not improved and its credit rating still threatens to put the Company below investment grade categories. If

APS' credit rating is downgraded and it loses its investment grade rating, its cost to borrow money will increase significantly and ratepayers will ultimately pay more in the form of higher rates for the entire term of the debt issuance – typically 20 years. As RUCO witness, Dr. Ben Johnson noted in his Direct Testimony, "In this regard, it is important to note that issuance of additional debt bearing a high interest rate will weaken the firm's credit metrics, particularly its FFO to interest ratio, increasing the firm's financial risk, and potentially leading to a further bond downgrading." (Johnson Direct, p. 17) This downward spiral is not in the ratepayers' best interest. Additionally, as Dr. Johnson noted, it is entirely possible that a downgrade would prevent APS from finding financing under any terms. "The market for newly issued junk-rated debt is limited." (Johnson Direct, p. 16)

RUCO understands that for APS to improve its financial health, it will require more than just increasing APS' revenues. It will require a short and long term strategy that is likely to place the Company in a better financial posture. RUCO further understands that improving the Company's financial condition will not happen overnight. It will take years. For that reason, the Settlement Agreement establishes a five year "Plan Term" that creates a roadmap to rate stability and an improved financial condition. This goal is necessary to ensure that APS, the state's largest

energy provider, will continue to provide reliable service at reasonable and affordable rates.

The Settlement Agreement is a comprehensive strategy that provides a guiding hand for the utility to improve its financial condition in both the short and long term. It is far more than an Agreement that merely increases the Company's revenues. The revenue increase is one aspect, but the $700 million equity infusion, the reduction of total debt to capital, the performance requirements and the other provisions in the Settlement Agreement provide ratepayers assurance that this is not just a short sighted attempt to solve a more systemic problem. The Settlement Agreement helps to align the interests of stockholders and ratepayers, and it sets forth a reasonable and rational strategy that is likely to improve APS' financial metrics and, in the long run, stem the constant flow of rate increases that would be likely to occur if the Commission were simply to continue to increase rates incrementally without addressing the root of the Company's weak financial position. The Settlement Agreement is in the public interest.

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RATE INCREASE/RATE STABILITY

Q Why is rate stability an important element in this Settlement Agreement?

A. The Settlement Agreement provides there will be no new base rate increases prior to July 1, 2012. Ratepayers will know their base rates will not change for at least the next 2 ½ years.

The Settlement Agreement also informs ratepayers that the Company will not file its next two rate cases prior to June 1, 2011 and June 1, 2013. There is value in knowing that rates will remain the same for an extended period. Rate stability is a benefit to ratepayers and is in the public interest.

RATE IMPACT

Q. What will be the impact on the average residential customer's bill if the Commission approves the Settlement Agreement?

A. I would call the Commission's attention to the Bill Impact Statement filed May 15, 2009. That Statement provides the rate impact for two types of residential customers: 1) the average residential customer for all residential rates; and 2) the average E-12 customer.

For the reader's convenience, I have attached a copy of the filed Bill Impact Statement as Attachment A to my testimony.

The Bill Impact Statement shows that the residential rates will experience a 12.82% increase in base rates. Once the rates go into effect, the average residential customer will see a $6.32 (4.83%) increase in their monthly bill. The average E-12 customer's monthly bill will increase $4.88 (5.28%).

Q. How can there be a 12.82% rate increase with only a 4.83% increase in the average residential monthly bill?

A. As described on page 2 of the Bill Impact Statement, there is a 12.82% increase in the residential ***base*** rate. This increase in the base rate rolls in several charges that customers are already paying as separate line items on their monthly bill. 2.27% of the 12.82% base rate increase reflects the $65.2 million interim rate surcharge that the Commission approved in December 2008 in Decision No. 70667. 5.11% of the 12.82% base rate increase shifts fuel costs currently captured in the PSA into the base rate. The remaining 5.44% of the 12.82% base rate increase reflects the additional increase in non-fuel costs to the customer associated with this rate case.[2]

It may be simpler to reference Section 3.3 of the Settlement Agreement which states that the total non-fuel base rate increase represents an

[2] In the 2007 APS rate case, the Commission awarded a 12.33% increase over test year revenues. As in this matter, a significant portion of that increase moved fuel costs from the PSA into base rates.

approximate 7.9% increase in base rate revenue. The 7.9% consists of the 1) $65.2 million in interim rates already granted by the Commission; 2) $11.2 million associated with establishing new base fuel levels[3]; and 3) $131.1 million of additional revenue negotiated through this Settlement Agreement.

Q. So then residential customers can expect that they will only see on average a $6.32 increase in their total monthly bill?

A. Not quite. As noted below the charts showing the proposed bill impact for all residential customers and E-12 customers, this $6.32 increase does not include increases to the DSMAC and RES adjustors for projects contemplated by the Settlement Agreement. Changes in the rate of these two adjusters are made annually and reflect the added costs for the DSM and renewable energy projects contemplated by this Settlement Agreement. In 2010, the Bill Impact Statement projects that the DSMAC would increase by an additional $0.51 (39%) for a total DSMAC cost of $1.22 and the RES adjustor would increase by an additional $0.86 (66%) for a total cost of $4.03. Section 3.9 of the Settlement Agreement points out:

> "The presently estimated impact of this Agreement on the amount to be collected from the DSMAC and RES in 2010 is approximately an additional $15 million and $2 million respectively. Although the Signatories agree that

[3] As explained in footnote 1, the Settlement Agreement shifts recovery of fuel costs from the PSA to base rates. Since the PSA has a 90/10 sharing mechanism that is not recognized when fuel costs are recovered in base rates, an additional $11.2 million is retained by the Company.

> the amounts collected under the DSMAC and RES will likely increase after 2010, there is no consensus as to the level of such increase."

Q. Why should customers accept a 39% increase in their DSMAC charge and a 66% increase in their RES charge?

A. RUCO believes it is in the customers' interest to support DSM / energy efficiency measures and the accelerated promotion of renewable energy generation. The DSM / energy efficiency measures found in Section XIV serve an important purpose. These measures have the effect of reducing energy consumption. A reduction in energy consumption delays the need to build additional plant and purchase additional fuel. In many ways, paying for energy efficiency can be actually less expensive than paying to build and operate new power plants or purchase energy on the wholesale market.

The Settlement Agreement provides for an expanded and comprehensive energy efficiency program including: 1) energy efficiency goals through 2012 with a tiered performance incentive program; 2) a commitment to install DSM elements in at least 100 schools by 2010; 3) a goal to serve 1,000 homes through a "Residential Existing Homes Program" by 2010; 4) additional incentives for increased efficiency construction in new homes; 5) a fully integrated non-residential customers repayment/financing

program to encourage greater participation; and 6) second tier high performance new construction elements.

RUCO believes that there are numerous benefits to the renewable energy projects listed in the Settlement Agreement. The Settlement outlines important investments in Arizona's renewable energy future including: 1) renewable energy generation of 1.7 million megawatts in service by 2015 which equates to 10% of retail sales; 2) renewable energy projects for schools; 3) an in-state wind generation project and 4) a utility scale photovoltaic generation project. Without discounting the numerous environmental benefits of renewable energy, there are strong financial reasons for promotion of these renewable energy projects. There is a possibility that Congress may impose a "cap and trade" program or a carbon tax that would significantly increase the cost of coal-fired generation. If so, APS' baseload plants such as Four Corners and Cholla may face significantly increased costs. Then, the renewable energy projects envisioned in this Settlement may serve, *in part*, to replace coal-fired generation instead of relying more on APS' expensive natural gas peaking plants. A diverse fuel portfolio with more renewable energy components will help shield APS from any federal legislation that adversely impacts the price of coal-fired generation. The Settlement Agreement envisions approximately 10% of APS' retail sales to be from renewable energy by 2015 which exceeds the goals established by the Commission's REST rules. Furthermore, Governor Brewer has

announced that $20 million from federal stimulus funds will be available through the School Facilities Board for energy efficiency and renewable energy projects at Arizona's schools. Money collected from the RES adjuster can be used to leverage these stimulus funds to maximize renewable energy project dollars. An additional $0.86 per month may be a wise investment in Arizona's energy future.

Q. What was RUCO's position in its direct case?

A. Page 13 of the Settlement Agreement details the revenue requirement positions of APS, Staff, RUCO and AECC in its respective direct cases. Originally, RUCO did not recommend any increase to non-fuel base rates. RUCO's direct testimony made a concerted effort to illustrate the effects of a pure application of a historical test year to this rate case application. RUCO held to a firm cut-off date of December 31, 2007 and rejected ***all*** post test year plant – even $92 million of plant placed in service on January 19, 2008 (Palo Verde Unit 3 steam generator).

Q. What made RUCO diverge from its original position and agree to a $196.3 million non-fuel base rate increase in the Settlement Agreement? ($131.1 million in addition to the already-approved $65.2 million interim rate)

A. Even at the time of filing its Direct Testimony, RUCO noted that the Commission may wish to veer from a hard-line, pure historical test year

analysis. RUCO witness Dr. Johnson stated, "I realize the Commission might conclude that some deviation from a strict historical test year is warranted...Accordingly, I have provided an appendix to my testimony in which I discuss the attrition issue in more depth, and I describe an alternative approach to attrition compensation which is not based on a series of arbitrary adjustments to the historical test year." (Johnson Direct, p. 33) On the very first page of the filed testimony, former Director Stephen Ahearn noted, "I strongly urge the reader...to also pay attention to the Appendix."

In Appendix B, Dr. Johnson addressed the issue of attrition. "Attrition" refers to a utility's profitability eroding over time. As Dr. Johnson noted, there is reason to accept APS' contention that the Company is suffering from attrition and may be a factor in the Company's earnings shortfall of $321 million between 2003 and 2007 and a projected shortfall of $384 million to $454 million through 2010. Dr. Johnson explained, "Assuming the utility is allowed to pass fuel and purchased power cost increases through to consumers, the most likely circumstance in which a utility might experience continued erosion of its profitability (attrition) is when the utility is investing substantial amounts in additional plant and equipment with higher unit costs than its existing facilities – assuming the adverse impact of inflation on these new investments outweighs the beneficial impact of increased economies of scale that often accompanies such growth." APS

construction costs were $808 million in 2005, $660 million in 2006 and $897 million in 2007. APS projects construction expenditures totaling approximately $1 billion per year from 2008 to 2010. (Johnson, Appendix B, pp. 2-3).

While RUCO takes note of APS' attrition argument, it also recognizes that the cause of APS' strained financial condition may also be the result of poor business practices and management decisions. RUCO finds that the Settlement Agreement addresses these possible causes of lost profitability as well. The Settlement Agreement requires APS to reduce its expenses by $150 million over the next five years, meet specified performance goals, limit its executive cash incentive compensation if it fails to meet these performance goals, improve its capital structure by reducing its total debt from 57% to 52%, and make equity infusions of at least $700 million.

The Settlement Agreement also requires APS to conduct a benchmarking study. This study will identify how APS compares to other similarly situated utilities regarding debt/equity ratios, FFO/debt ratios and debt ratings. This study can show how APS' financial condition has improved under the terms of the Settlement Agreement and how much farther it has to go toward complete financial health.

Under these circumstances, RUCO finds that the $196.3 million increase (which includes the $65 million the Commission already authorized through interim rates) is reasonable. Furthermore, RUCO finds that the revenue requirements in the Settlement Agreement appropriately address RUCO's concerns that failure to address attrition will result in a utility filing a series of back-to-back rate cases in an effort to "catch up" with attrition. Furthermore, this non-fuel base rate increase is only a single aspect of the Settlement Agreement. Placed with all of the other components listed above, the Settlement Agreement provides APS the tools needed to regain its financial strength and become attractive to investors, improve its credit rating and lower its cost of debt.

Q. Why would RUCO agree to non-traditional ratemaking elements to enhance APS' financial viability?

A. As discussed above, RUCO is deeply troubled by APS' financial condition. RUCO believes that it is not in the best interest of the consumers to have APS facing a credit rating downgrade, having trouble attracting investors and acquiring debt at less than attractive interest rates. Strict adherence to a historical test year would not solve the problem. The Settlement Agreement recognizes post test year plant 18 months beyond the test year. Furthermore, the Settlement Agreement contains provisions that allow APS to increase its earnings such as 1) defer pension and OPEB expenses; 2) treat Schedule 3 as revenue; and 3) adjust depreciation

rates for Palo Verde license extension. While not traditional ratemaking elements, RUCO accepted these provisions because their treatment allows APS to improve its revenues ***without having to increase rates at this time***.

EQUITY INFUSIONS/TOTAL DEBT TO CAPITAL

Q. Explain why RUCO believes it's important that APS "strive to achieve a capital structure with no more than 52% total debt" as indicated in the Settlement Agreement?

A. RUCO finds this provision to be critical to improving APS' financial condition. As Dr. Johnson noted, "The debt to capital ratio computed by S&P is significantly worse than the analogous debt ratio which was approved by the Commission in the last rate case. This 57% debt ratio places APS near the unfavorable end of the range for the "Aggressive" financial risk category." (Johnson Direct at p. 15)[4] The higher the total debt percentage the more a company is leveraged. The more a company must focus on a disproportionate debt repayment obligations, the less likely it will be to attract equity investors seeking dividends.

Reducing APS' total debt will improve the Company's financial position and increase the likelihood of improved credit ratings. Improved credit

[4] Section 4.1 adopts a capital structure of 46.21% debt and 53.79% equity for ratemaking purposes. However, this is for ratemaking purposes only and does not reflect APS' imputed debt levels.

ratings allow APS to borrow (or refinance debt) on more favorable terms. Since ratepayers must pay these costs, it is definitely in the best interests of the ratepayers that APS be able to issue debt on favorable terms.

Q. Why is the requirement that APS make $700 million of equity infusions an important consumer benefit?

A. Section VIII of the Settlement Agreement requires APS to complete equity infusions of at least $700 million by December 31, 2014. Increasing the amount of equity in APS is an important element in improving the Company's financial metrics. In fact, the Commission recognized its importance in Decision No. 70454 when is authorized APS to increase its equity by up to $400 million. Increased equity and the reduction in total debt to capital are intertwined. As Dr. Johnson mentions in his testimony, they "reinforce" one another.

APS LINE EXTENSION POLICY

Q. What is RUCO's position regarding the "free footage" line extension issue for single residential customers as discussed in letters to the docket filed by Commissioners Kennedy, Mayes, Newman and Stump?

A. As RUCO articulated in its May 15, 2009 letter filed in this docket, there is no such thing as a "free" line extension. Costs that are not paid by the party receiving the extension are paid by all other ratepayers.

The previous "free footage" policy allowed single residential landowners to receive the first 1,000 feet of line without cost as long as that cost did not exceed $25,000. (Business and commercial properties, and those residential landowners who needed connections as part of a planned subdivision were not eligible for this 1,000 feet/$25,000 "free footage" allotment.) If the cost exceeded $25,000, the single residential landowner had to pay the entire cost of the extension – not just the incremental cost over $25,000. This policy had been in place for several decades before being changed in the Company's last rate case to remove the subsidy in base rates paid by all ratepayers and place the cost on the person receiving the benefit of the line extension.

RUCO understands that the Commission has received several complaints regarding this policy change. Opponents of the current policy contend that it hinders development and economic growth and suppresses property values. The Commission has received letters from County Supervisors, County Assessors and a State Senator expressing these concerns.

RUCO supports Section 10.3 of the Settlement Agreement to maintain the current line extension policy that requires a residential landowner to pay the entire cost of a line extension to his or her property. RUCO believes this is an appropriate policy decision of the Commission that applies not only to APS but to line extensions in the TEP service territory as well. Any

change in this docket would have the two largest electric service territories treating line extensions differently for their single, residential customers. Furthermore, RUCO believes that the clarifications to the line extension policy found in Section 10.7 may help customers understand the policy, its costs and options and can reduce the number of complaints.

In light of the revenue requirements of the Settlement Agreement any change to allow some degree of "free footage" would increase all customers' bills and exacerbate the rate increase. However, since four of the five Commissioners have filed letters in the docket on this issue, it appears to RUCO that there is an interest in re-examining the line extension policy. Therefore, if the Commission finds it appropriate to return to some version of the previous free line extension policy, RUCO would not object to the following:

1. That the policy change only be in effect for a temporary period of time to recognize the unique economic times the State and its residents currently face. A temporary departure from the current policy may ameliorate the economic hardships residential landowners are facing during this recession. Furthermore, a temporary change will give the Commission information to determine whether the elimination of the free footage allotment truly affected property values or hindered development.

2. Adopt a modified and limited "free footage" policy that allows a sizeable portion of single residential landowners to extend power to their property while minimizing the rate increase to the rest of the customers. Any change certainly should not be more generous than the previous 1,000 feet/$25,000 policy.[5]

Q. Does your silence on issues not addressed in your testimony imply any disfavor or reluctance of RUCO's support?

A. No. RUCO supports the Settlement Agreement and urges the Commission to adopt it in its entirety. RUCO understands that other parties will address other provisions in greater detail.

Q. Does this conclude your testimony?

A. Yes.

[5] For illustrative purposes, if the Commission were to adopt a temporary line extension policy of no more than 500 feet/$10,000, according to information filed on June 25, 2009 by APS, ratepayers would pay an additional $2.76 million in 2010, $3.14 million in 2011 and $4.55 million in 2012. Also according to APS, for every $5 million paid by other ratepayers to provide some sort of "free footage" the average residential ratepayer bill would increase by $0.20. Therefore a 500 feet/$10,000 policy would increase the average residential ratepayer's bill by $0.11 in 2010, $0.13 in 2011 and $0.18 in 2012.

ATTACHMENT A

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RULEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-08-0172 **STAFF'S NOTICE OF FILING CUSTOMER BILL IMPACT STATEMENT**

Staff of the Arizona Corporation Commission ("Staff"), on behalf of the Settling Parties in this case, hereby files the Customer Bill Impact Analysis referred to in Item O of the Term Sheet filed by the Settling Parties on May 4, 2009. The Analysis was prepared with the input of all Settling Parties using the agreements in principle reached between the Settling Parties as set forth in the Term Sheet. The narrative explanation that precedes the actual bill comparison is intended to provide clarity and additional detail on the development of the rates and percentage increases for each customer class.

RESPECTFULLY SUBMITTED this 15th day of May, 2009.

Arizona Corporation Commission
DOCKETED
MAY 15 2009
DOCKETED BY

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Kaye Christensen

APS Rate Case Settlement Proposal
Bill Impact Analysis

May 15, 2009

PURPOSE AND SCOPE: An important consideration in any proposal to change rates is how the change impacts customer bills. Key factors to be considered in allocating revenue responsibility and designing rates include: the cost of providing service, rate stability, encouraging conservation, and other public policy objectives. The Settling Parties considered such factors in their pre-filed testimony and in reaching a comprehensive settlement.

A bill impact analysis is intended to provide policymakers and customers with a general sense of how rate changes will affect typical bills for different classes of customers. When only one bill element is changed, such as the basic service charge, a bill impact analysis is relatively straightforward. However, when multiple billing elements are involved in a change to rates, the bill impact analysis is necessarily more complex. This is because the multiple billing elements comprising an overall base rate change affect customer classes differently, depending on things such as load factor (average energy used by a customer expressed as a percentage of their maximum usage) and overall electric consumption levels. This is true even when the overall base rate percentage increase is the same for all customer classes. A typical bill analysis for residential customers is set forth on page 3 of this document.

THE PROPOSED SETTLEMENT: The Settling Parties propose that all customer classes bear roughly the same increase to the 2007 Test Year base rates—which on a percentage basis is 13.07%.[1] In addition, the parties propose to spread the impact of holding low income E-3 and E-4 customers harmless from the base rate increase across all other customers. As a result, there are four elements that affect the base rate increase and the bill impact analysis in this case:

- Designing rates such that E-3 and E-4 low income customers are held harmless, by spreading those costs across customer classes on a per kWh basis;
- Moving a portion of fuel and purchased power costs from the PSA to base rates;
- Eliminating the separate interim base rate surcharge and incorporating that charge into base rates; and

[1] In APS's 2005 Settlement Agreement, Commercial and Industrial customer classes were allocated proportionally less of the base rate increase and the Residential class was allocated proportionally more of the base rate increase to move rate design closer to the results of the cost of service study. Although the cost of service study in the current rate case continues to show that Commercial and Industrial classes are paying proportionally more than their cost of service relative to Residential customers, the parties agreed that no further rate design changes towards cost of service would be performed in this case. Such a change would have required Residential customers to pay more than the average base rate increase.

- Including the non-fuel increase necessary to bring base rates to the agreed upon 13.07% customer class average increase.

THE IMPACT BY CLASS: Some of these bill elements, such as fuel and purchased power, affect classes of customers differently. Commercial and industrial customers, for example, will pay a higher proportion of fuel and purchased power costs in their 13.07% base rate increase because as a class they consume more energy as a proportion of their overall bill. Although the Settling Parties did not strictly follow the cost of service in designing rates, this result is consistent with the cost of service study, which shows that the cost of service for commercial and industrial customers includes a higher percentage of fuel-related costs than the cost of service study for residential customers. Similarly, the interim base surcharge was established earlier this year as a kWh-based surcharge, which means that it currently represents a higher proportion of a typical commercial and industrial customer's bill, than that of a residential customer. Thus, the effect of an equal percentage increase in base rates will result in each class of customers paying a different proportion of each element in order to reach the overall 13.07% increase on a class basis.

A summary of the average cost (expressed on a percentage basis) for customers of each class associated with each element of the base rate increase, after accounting for the rate design effect of holding E-3 and E-4 customers harmless,[2] is shown in the following table:

	Beginning Base Rate Revenue Increase	Class Impact of E-3/E-4 Hold Harmless Rate Design	Increase in Base Rates After E-3/E-4 Rate Design (A)+(B)+(C)	Fuel-Related Increase (A)	Non-Fuel Related Increase (B)	Increase Related to Interim (C)
Residential (All Rates)	13.07%	-0.25%	12.82%	5.11%	5.44%	2.27%
Commercial (E-32)	13.07%	0.24%	13.31%	5.69%	5.09%	2.53%
Industrial	13.07%	0.24%	13.31%	5.67%	5.12%	2.52%

As the table shows, commercial and industrial customers will typically pay a higher proportion of the base rate increase for fuel-related costs, as these customers consume proportionally more fuel than residential customers. In turn, residential customers will pay less of the base rate increase in fuel-related costs and more in non-fuel related costs, reflecting the class average cost of service.

THE IMPACT ON TYPICAL BILLS: Finally, the bill impact analysis involves comparing a change in base rate (and associated billing elements) to a total monthly bill. The total monthly bill includes not just base rates, but also different charges such as the RES Adjustor and the DSM Adjustment Clause, which also represent a larger or smaller

[2] From a customer class standpoint, E-3 and E-4 customers are part of the Residential class. Thus, the column entitled "Increase in Base Rates After E-3/E-4 Rate Design" reflects the fact that customers in the Commercial and Industrial classes are contributing rate design revenues associated with the hold harmless provision for these low income rates to the Residential class.

overall component of the bill for a given customer class. For example, residential and industrial customers pay proportionately less than commercial customers for the RES, while industrial and commercial customers pay proportionately more for the DSM Adjustment Clause. Thus, the percentage of total bill impact depends not only on the level of the overall base rate increase, but also the relative levels of other line items on the bill.

Attached are bill impact analyses for each major customer class. To provide for better comparability of percentage bill impacts, the commercial and industrial analysis presented reflect an E-32 and E-34/35 customer with a similar load factor to that of the residential class. Also, a bill impact analysis for a typical E-12 residential customer, which is the non time-of-use rate, with 763 kWh of average monthly consumption is included.

For example, for a typical residential customer, with average monthly consumption of 1,408 kWh during summer months and 930 kWh for winter months, the increase would be $8.98 per month in the summer and $3.67 per month in the winter or an annual average of $6.32 per month. In the case of a residential customer on rate E-12 with average monthly consumption of 880 kWh during summer months and 645 kWh for winter months, the increase would be $6.67 per month in the summer and $3.11 per month in the winter, or an annual average of $4.88 per month. For an E-12 customer with median monthly usage of 664 kWh during summer months and 499 kWh for winter months, the increase would be $3.19 per month during the summer and $3.26 per month during the winter for an annual average of $3.22 per month.

The settlement also proposes approval of new demand response programs and increased energy efficiency programs. *These new programs, as well as existing programs* (such as TOU rates) provide customers with the opportunity to mitigate all or a portion of the proposed rate increase by managing their energy usage.

Additionally, some provisions of the settlement involve costs recovered through adjustment mechanisms. Thus, estimates of 2010 DSM Adjustment Clause and the 2010 RES are provided for illustrative purposes, but would not be implemented at the same time as base rates increase.

Monthly Bill
Rate Case Settlement Proposal
May 14, 2009

ARIZONA PUBLIC SERVICE COMPANY
Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 5/4/09

Residential (Average - All Rates)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)		Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	1,169	1,169		1,408	1,408	930	930
Base Rates	$ 116.20	$ 131.10		$ 150.41	$ 169.72	$ 81.99	$ 92.48
PSA- Forward Component	5.94	-		7.15	-	4.72	-
PSA - Historical Component	0.30	0.30		0.36	0.36	0.24	0.24
Interim Rate Adjustor (January 2009)	2.64	-		3.18	-	2.10	-
TCA (July 1, 2008)	1.42	1.42		1.70	1.70	1.13	1.13
CRCC (April 2005)	0.40	0.40		0.48	0.48	0.31	0.31
EIS (July 2007)	0.19	0.19		0.23	0.23	0.15	0.15
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.71	0.71		0.85	0.85	0.56	0.56
Total	$ 130.97	$ 137.29		$ 167.53	$ 176.51	$ 94.37	$ 98.04
Bill Impact (3)		$ 6.32			$ 8.98		$ 3.67
Percent Bill Impact		4.83%					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC		$ 0.51	0.39%		$ 0.61		$ 0.40
Increase from Projected 2010 RES (4)		$ 0.86	0.66%		$ 0.86		$ 0.86

Residential (Rate E-12)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	763	763		880	880	645	645
Base Rates	$ 81.71	$ 92.20		$ 102.11	$ 115.24	$ 61.30	$ 69.15
PSA- Forward Component	3.88	-		4.47	-	3.28	-
PSA - Historical Component	0.20	0.20		0.23	0.23	0.17	0.17
Interim Rate Adjustor (January 2009)	1.73	-		1.99	-	1.46	-
TCA (July 1, 2008)	0.92	0.92		1.06	1.06	0.78	0.78
CRCC (April 2005)	0.26	0.26		0.30	0.30	0.22	0.22
EIS (July 2007)	0.12	0.12		0.14	0.14	0.10	0.10
RES (Jan 1, 2009)	3.17	3.17		3.17	3.17	3.17	3.17
DSMAC (April 2009)	0.46	0.46		0.53	0.53	0.39	0.39
Total	$ 92.45	$ 97.33		$ 114.00	$ 120.67	$ 70.87	$ 73.98
Bill Impact (3)		$ 4.88			$ 6.67		$ 3.11
Percent Bill Impact		5.28%					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Increase from Projected 2010 DSMAC		$ 0.33	0.36%		$ 0.38		$ 0.28
Increase from Projected 2010 RES (4)		$ 0.86	0.93%		$ 0.86		$ 0.86

ARIZONA PUBLIC SERVICE COMPANY

Preliminary Estimated Monthly Bill Impacts of Proposed Settlement Rates 5/4/09

Commercial (Rate E-32)	Current Rates Annual Average Monthly Bill (1)	Proposed Rates Annual Average Monthly Bill (2)		Current Rates Summer Monthly Bill	Proposed Rates Summer Monthly Bill	Current Rates Winter Monthly Bill	Proposed Rates Winter Monthly Bill
Average kWh per Month	8,663	8,663		9,628	9,628	7,698	7,698
Base Rates	$ 773.63	$ 876.58		$ 912.51	$ 1,033.82	$ 634.75	$ 719.34
PSA- Forward Component	44.01	-		48.91	-	39.11	-
PSA - Historical Component	2.24	2.24		2.48	2.48	1.99	1.99
Interim Rate Adjustor (January 2009)	19.58	-		21.76	-	17.40	-
TCA (July 1, 2008)	15.03	15.03		16.72	16.72	13.33	13.33
CRCC (April 2005)	2.93	2.93		3.25	3.25	2.60	2.60
EIS (July 2007)	1.39	1.39		1.54	1.54	1.23	1.23
RES (Jan 1, 2009)	68.76	68.76		76.42	76.42	61.10	61.10
DSMAC (April 2009)	6.44	6.44		7.16	7.16	5.71	5.71
Total	$ 934.01	$ 973.37		$ 1,090.75	$ 1,141.39	$ 777.22	$ 805.30
Bill Impact (3)		**$ 39.36**			$ 50.64		$ 28.08
Percent Bill Impact		**4.21%**					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Impact from Projected 2010 DSMAC		$ 3.75	0.40%		$ 4.17		$ 3.33
Impact from Projected 2010 RES		$ 18.63	1.99%		20.70		16.55

Industrial (Rate E34/35 Medium Load Factor)	Annual Average Monthly Bill (1)	Annual Average Monthly Bill (2)		Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill	Winter Monthly Bill
Average kWh per Month	2,250,284	2,250,284		2,344,877	2,344,877	2,155,690	2,155,690
Base Rates	$ 201,730.06	$ 228,573.49		$ 210,208.60	$ 238,180.24	$ 193,251.52	$ 218,966.74
PSA- Forward Component	11,431.45	-		11,911.98	-	10,950.91	-
PSA - Historical Component	580.58	580.58		604.98	604.98	556.17	556.17
Interim Rate Adjustor (January 2009)	5,085.64	-		5,299.42	-	4,871.88	-
TCA (July 1, 2008)	2,666.44	2,666.44		2,778.52	2,778.52	2,554.35	2,554.35
CRCC (April 2005)	760.60	760.60		792.57	792.57	728.62	728.62
EIS (July 2007)	360.05	360.05		375.18	375.18	344.91	344.91
RES (Jan 1, 2009)	353.78	353.78		353.78	353.78	353.78	353.78
DSMAC (April 2009)	2,106.39	2,106.39		2,194.93	2,194.93	2,017.84	2,017.84
Total	$ 225,074.99	$ 235,401.33		$ 234,519.96	$ 245,280.20	$ 215,629.96	$ 225,522.41
Bill Impact (3)		**$ 10,326.34**			$ 10,760.25		$ 9,892.45
Percent Bill Impact		**4.59%**					
Reduction from accelerated reset of PSA Historical Component		TBD	TBD		TBD		TBD
Impact from Projected 2010 DSMAC		$ 1,507.55	0.67%		$ 1,570.92		$ 1,444.18
Impact from Projected 2010 RES		$ 95.83	0.04%		95.83		95.83

Notes:

(1) Bill excludes regulatory assessment charge, taxes and fees. Adjustor levels and interim base rate surcharge in effect as of May 1, 2009.

(2) Bill impacts reflect the proposed increase in base rates, reset of interim adjustor to zero, and reset of PSA Forward Component charge to zero.

(3) Bill impacts for commercial and industrial customers are less than residential on a percentage basis because these customer classes were assessed proportionally more for the interim adjustor and the PSA. The base rates reflect approximately the same percentage increase as residential.

(4) RES impacts are based on a preliminary estimate. *Actual bill impacts will be filed with the 2010 implementation plan to be filed in July 2009.* Of the projected increase in the RES budget for 2010, only about $1 to $2 million is attributable to the settlement.

Increase Over Base Rates for Representative Customers

	Beginning Base Rate Revenue Increase	Impact of E-3, E-4 Hold Harmless Rate Design	Increase in Base Rates After E-3, E-4 Rate Design (A) + (B) + (C)	Fuel Related Increase (A)	Non-Fuel Related Increase (B)	Increase Related To Interim (C)
Residential (All Rates)	13.07%	-0.25%	12.82%	5.11%	5.44%	2.27%
Residential (Rate E-12)	13.07%	-0.23%	12.84%	4.75%	5.97%	2.12%
Commercial (Rate E-32)	13.07%	0.24%	13.31%	5.69%	5.09%	2.53%
Industrial (Medium Load Factor)	13.07%	0.24%	13.31%	5.67%	5.12%	2.52%

Monthly Bill
Rate Case Settlement Proposal
May 14, 2009

INPUT TO BILL COMPS
Proposed Increase - GRC Settlement Proposal

	Increase ($000)	%
Base Rate	196,300	7.44%
Fuel - base rates	11,203	0.42%
Total base rate increase	207,503	7.87%
Adjusted base cost of fuel increase	137,235	5.20%
Total base rate increase	344,738	13.07%
Adjusted Present Revenue - base rates ($000)	2,637,447	

Adjusted TY MWh	28,855,123
TY E-3, E-4 MWh	460,909
net	28,394,214

Revenue Requirement E-3, E-4 hold harmless	$	6,000,000	
rev requirement $/kwh	$	0.0002113	
Residential TY adjusted kWh		13,556,815,396	
TY E-3, E-4 MWh		460,909,000	
net		13,095,906,396	
residential benefit $/kWh	$	0.0004582	
		(0.0002468)	net residential impact $/kwh
		(0.0002468)	check from class average assessment

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ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-08-0172

REPLY TESTIMONY
IN SUPPORT OF SETTLEMENT AGREEMENT

OF

JODI A. JERICH, DIRECTOR

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 13, 2009

1 TABLE OF CONTENTS

2

3 INTRODUCTION 1

INTRODUCTION

Q. Did you file testimony in support of the proposed APS Settlement?

A. Yes.

Q. What is the purpose of your reply testimony?

A. The purpose of my testimony is to reaffirm RUCO's position regarding the APS line extension policy established by the Corporation Commission and to address the Direct Testimony in Opposition to the Proposed Settlement.

Q. Have you read the testimony opposing the settlement including the Fiscal Impact Study completed by Elliot Pollack & Company?

A. Yes, I have read the testimony. I also attended the depositions of Rick Merritt and Daniel Court who conducted the Study on behalf of the Company. Additionally, I reviewed the transcripts of those depositions. Members of RUCO staff attended the public comment sessions held in Flagstaff and Prescott where a number of residents voiced their opinions regarding the line extension policy.

Q. Briefly summarize RUCO's position on the line extension policy proposed in the Settlement Agreement.

A. As I mentioned in my Direct Testimony in Support of the Proposed Settlement Agreement, 20 parties, including RUCO, have committed their support for the proposed Settlement Agreement. That Settlement Agreement preserves the

line extension policy established by the Commission in the 2007 APS rate case. Since that previous APS rate case, the Commission has also instituted that same line extension policy to other electric utilities, such as TEP. In an effort to address concerns and confusion about this change in policy, the Settlement requires APS to do a better job in informing its customers about the itemized costs of line extensions. Furthermore, the Settlement requires APS to inform customers that they have the option of "sub-contracting" some non-electrical work (such as trenching) to a vendor other than APS.

Four of the five Commissioners have filed letters in this docket on this issue. Clearly, there is an interest in re-examining the line extension policy. As stated in my direct testimony, RUCO recognizes that the Commission may find it appropriate to return to some version of the previous free footage allocation for individual landowners. In that direct testimony (pp. 24-25), I noted that any change should not go beyond the previous 1,000 feet/$25,000 policy and that any change should have as little of an impact on ratepayers as possible. There is nothing free about a "free footage" allowance. Furthermore, if the Commission finds a reversal of policy compelling due to current economic conditions, then it would be appropriate for this change in policy to remain in effect only for a temporary period of time in recognition of the unique economic times the State and its residents currently face. At the conclusion of that period of time, there will be sufficient evidence to see if the change has had a positive, quantifiable impact on property values and land

development compared to the 2007-2009 time period when there was no free footage allowance in the APS service territory.[1]

Q. Are you aware of the Commission's decisions to hold a series of workshops on the issue of free footage allowances in line extension policies?

A. Yes. RUCO understands that in a recent staff meeting the Commissioners directed Commission Staff to set up a series of workshops to reexamine this issue. RUCO supports the Commission's action and believes ***if a new policy is adopted, it should be fair not only to landowners, but also to the ratepayers who will pay for any "free" footage.***

Q. Briefly summarize the testimony in opposition to the proposed settlement agreement.

A. Several real estate agents and land developers filed testimony in opposition to the current line extension policy. The witnesses provided examples of situations where landowners cannot afford to pay for the line extension to their undeveloped parcel of land. For at least two of the examples, it is apparent that their line extensions would have fallen within the 1,000 foot/$25,000 feet limit (Testimony of Ian Campbell, p. 1 and Debra Morrow, p.

[1] In footnote 5 of my direct testimony, I noted that according to information filed by APS on June 25, 2009, if the Commission were to adopt a modified 500 feet/$10,000 free footage allowance, the financial impact is estimated to be $2.76 million in 2010, $3.14 million in 2011 and $4.55 million in 2012. If the Commission were to shift the cost burden from the individual landowner to other ratepayers, the average residential ratepayer would see an increase in their monthly bill of approximately $0.11 in 2010, $0.13 in 2011 and $0.18 in 2012 as a result of this policy change.

1). It is unclear whether the other examples provided would have benefitted from the previous policy since the previous policy held that if an extension exceeded $25,000 then the landowner paid the entire cost of the extension – not merely the costs that exceed $25,000.

The testimony filed in opposition to the current policy as well as the comments expressed at the public comment meetings make it obviously clear that the 2007 change in the policy has resulted in certain individual landowners not being able to afford to bear the costs of providing electricity to their land. RUCO recognizes that this anecdotal testimony may provide some indication of the impact of the change in the policy. However, consideration of any negative impact that this policy may have for certain individual landowners should not be the only factor considered in evaluating the public interest. It is important to weigh the impact on landowners against the benefit of maintaining lower electric rates for the vast majority of ratepayers.

The sentiment of all those who filed testimony in opposition to the current line extension policy can best be summed up through the testimony of Chad Fisher:

> "I support a free footage allowance of 1,000 ft with a $25,000 cap, which is the same line extension policy that was in place prior to July 2007. It is my understanding that any changes to service schedule 3 must remain revenue neutral. The testimony of David Rumolo states that estimated impact of returning to the prior service agreement of 1,000 ft free (if under $25,000) to be

> $5,950,000 in 2010 and increased to $10,000,000 in 2012. Also in his testimony he stated that in order to remain revenue neutral, APS estimates that each $5,000,000 of reduced schedule 3 revenues would require an additional rate increase of roughly $.20 per month." (Fisher at p. 1)

Q. Does the Impact Study that was filed with the testimony alter RUCO's position?

A. No. For the most part, the Study is not focused on the critical issues that need to be evaluated in deciding who should pay for a line extension.

- Is it in the broad public interest for all APS ratepayers to pay for the costs to individual parcels for a small number of landowners?
- Alternatively, is it a better policy to keep rates as low as possible for all ratepayers and have these costs borne by those who directly benefit from the line extension?
- Do the consequential benefits of developed land--arguably higher property values and better resale prices for undeveloped land--provide enough of a general, societal benefit to warrant the subsidization of individual line extensions by having all ratepayers pick up the costs for qualifying extensions?

The Study provides little consideration to these important public policy considerations. While RUCO sympathizes with the individual landowners who are affected by the 2007 elimination of the free footage allowance, RUCO believes that the benefit of maintaining lower electric rates for the majority of the ratepayers outweighs the interests of a few. For this reason, RUCO supports the provision in the Settlement Agreement that maintains the current line extension policy.

While the Study comes to the conclusion that the change in the line extension policy may negatively impact land values (Study at p. i), there is no quantifiable data presented to show the amount of the impact. Furthermore, there is nothing in the Study that distinguishes the impact the economic recession and the fallout of the real estate market have had on property values in comparison to the change in the line extension policy.

The Study itself states:

> "It is unclear the extent that any increase in the cost of energy and electrical infrastructure will impact builders' and businesses' perceptions about Arizona. It is also not clear the extent to which these perceptions will result in slower economic growth, fewer business expansions, or less homebuilding activity in the State...There is no way of knowing with complete certainty the extent to which the increased capital costs of extending power to a given site will result in fewer homes being built over the long run. Therefore, it is not possible to provide specific estimates of economic losses as a result of this new policy." (pp. 23-24)

Rick Merritt's deposition further illuminated the lack of correlation between the line extension policy and land values.

> "A. ...We did not conduct any analysis of land values or the potential impact of the service schedule, the changed Service Schedule 3 on the value of land.
>
> Q. You did not analyze the potential impact of Service Schedule 3 on the value of land?
> A. Correct.
>
> Q. Your study is thus not intended to present evidence that the change in line extension policies actually caused the economic impact you described in section 5 of your report?
> A. Correct...

> Q. Do I take it then that your study is not intended to present evidence that the change in line extension policies actually caused the impacts described in section 5?
> A. Our analysis says that there is not enough information available to determine what the impact would be of Service Schedule 3. But for every 100 homes that may not be built in this, in the APS service area or other service areas, there is a particular impact on jobs and revenue that would be developed and generated to cities, state, counties.
>
> Q. Do you have any evidence that 100 homes will not be built as a result of the changes to Service Schedule 3?
> A. No, we do not.
>
> Q. Do you have any evidence that 10 homes will not be built as a result of the change to Service Schedule 3?
> A. No, we do not."

While the Study does not provide concrete and quantifiable data on the financial impact of the change to the line extension policy, it does reflect the same sentiment expressed by those who filed testimony, the authors of several letters filed in this docket and the ratepayers who have attended the public comment meetings.

> "More than anything, the elimination of the no cost extension and other policies that helped to subsidize growth by these electric utility providers is an issue of *fairness*." (Study at p. 35).

As discussed in the Study and voiced at the public comment meetings, some landowners feel trapped in their undeveloped lots due to increased costs of construction that resulted with the 2007 policy change. Realtors and developers whose ability to earn a living has been severely restricted due to the economy feel that their troubles have only been magnified by the 2007 policy. Homebuilders who are looking for any advantage they can find to

keep their business doors open are seeking every opportunity to make it more affordable to build homes. The statistical data might be lacking, but the emotional tug of this issue is clear.

Q. Is there more to be considered in deciding whether the line extension policy should be changed again?

A. This Settlement Agreement is just like any other settlement in that it consists of numerous concessions, compromises and negotiated positions. For example, one provision of the Settlement may be directly linked to another provision and amending that one provision impacts the other. Such is the case with the issue of the line extension policy. In an effort to minimize the amount of the rate increase but still give APS sufficient operating revenues to construct a healthy ROE, improve its credit ratings and enhance its FFO/Debt ratio, the parties to the Settlement agreed that proceeds from Schedule 3 (line extensions) would be treated as revenue for the next few years (Section X). Currently, Schedule 3 proceeds are treated as Contributions in Aid of Construction.

...

...

Q. If the Commission decides to revise the line extension policy in this rate case to include some sort of equipment allowance or free footage allowance, how would that decision impact other components of the Settlement Agreement?

A. Treatment of Schedule 3 proceeds as revenue is a material provision of the Settlement Agreement. APS estimates Schedule 3 revenues to be $23 million in 2010, $25 million in 2011 and $49 million in 2012. These sums were a significant consideration in reaching an agreement on the revenue requirement and overall magnitude of the rate increase. Without this treatment of Schedule 3 proceeds, there was very little chance that the parties could have come to a mutually acceptable agreement on the size of the revenue increase. To further complicate the consideration of altering the existing line extension policy, Section X of the Settlement Agreement is directly linked to Section II. Section II prevents new base rates until at least July 1, 2012. Section II is particularly important to RUCO. Without sufficient revenue in years 2010, 2011 and 2012, APS would not be able to "stay out" for 2 ½ years without another rate case application. After a continuous string a rate cases, RUCO believes that the ratepayer deserves a break from increasing utility bills.

If the Commission does decide to alter the line extension policy to allow for some form of free footage or equipment allowance, it should recognize economic realities and find a viable alternative way to pay for these costs. If

the Commission does not allow the Company to recover the costs associated with a free footage allowance, the results will not be in the best interests of the residential ratepayer for three closely related, very important reasons.

First, if the Commission does not allow the Company to recover the expenses associated with line extensions in base rates or some other form of recovery, then the Company will pay for the costs of these line extensions from investor-provided capital. Typically, capital assets that are paid for in this manner will enter the rate base and the Company will receive a rate of return on these capital assets as well as reimbursement of the cost through the depreciation process. Over the long haul, this treatment will burden other ratepayers by substantially more than $0.20 per month (as mentioned earlier in my testimony) which is calculated based on immediate cost recovery.

Second, if the Settlement is rejected and a protracted and litigated rate case becomes necessary, it could produce detrimental consequences for APS ***and its ratepayers*** on Wall Street. It is certain that APS' credit ratings would not be upgraded and they may possibly be downgraded while the case is pending. This would affect APS' ability to borrow money at reasonable rates and even hamper its ability to attract investors to infuse equity into its capital structure (See RUCO direct testimony, Johnson at pp. 18-28, Jerich at pp.9-11). The Settlement Agreement requires APS to maintain investment grade ratios and to strengthen its capital structure with no more than 52% debt/total

capital, as well as a commitment to invest at least $700 million of equity into the Company (Section VIII). RUCO fought hard for these very important provisions. A change in the line extension policy without a corresponding increase in revenue could lead to the collapse of the Settlement Agreement. If this happens, a ratings downgrade may make it difficult – if not impossible – for APS to make the required improvements to its financial health as set forth in the Settlement Agreement. (Johnson Direct Testimony pp. 28-29).[2]

Third, it is possible that one or more parties may withdraw from the Settlement Agreement because of the material change to the revenue agreement. Such action would result in a protracted, litigated rate case with the potential for appeal. Unraveling the Agreement would bring about a cascade of other consequences. With this Settlement Agreement, the Commission has a great opportunity to bring important and far reaching energy efficiency and renewable energy goals to Arizona. While some of these measures are being contemplated in the energy efficiency workshop, the cost recovery mechanism in the Settlement Agreement is more ratepayer friendly then the options being proposed in the workshop. Furthermore, while the Commission may decide to increase RES minimum requirements, the Commission has the opportunity to bind APS to higher goals ***now*** through the Settlement Agreement. Finally, if the Commissioners want to adopt some

[2] APS noted that upon announcement of the Settlement Agreement, Pinnacle West's outlook was upgraded from "Neutral" to "Outperform". (See Hatfield Direct at p.9). It is logical that if reaching a settlement was beneficial, then the unraveling of the settlement would have a corresponding negative impact.

sort of free footage allowance in the APS line extension policy in this case, then that decision can be placed in effect sooner if the changes are effectuated in a manner that allows the Settlement Agreement to remain intact, thereby achieving a resolution to the rate case without lengthy (and appealable) litigation.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT
RUO-3
ADMITTED

My Direct Testimony in Support of the Settlement, pages 13-17, referenced and analyzed the Bill Impact Statement filed May 15, 2009 and discusses how the proposed rate increase impacts the average residential customer.

On July 13, 2009, APS filed a revised Bill Impact Statement which amends these dollar figures.

The record needs to note that the analysis in my Direct Testimony in Support of the Settlement is based on numbers that have now been superseded by the revised Bill Impact Statement. However, these revised numbers do not affect my analysis or conclusions about the base rate increase.

First, the revised Bill Impact Statement provides slightly different figures for the base rate increase which my Direct Testimony does not reflect. For example, in my testimony, I stated that the average residential ratepayer would see a $6.32 monthly increase in their base rate. Under the revised Bill Impact Statement, the average base rate increase is decreased to $6.24.

Second, the new Statement also provides significantly changed amounts for the DSMAC adjuster and the RES surcharge. However, these revisions also do not change my conclusion that these costs are reasonable and appropriate and that it is in the best interest of the ratepayer to support energy efficiency measures and the renewable energy generation proposed in the Settlement Agreement.

Under the Revised Bill Impact Statement, the RES surcharge for the average residential ratepayer is reduced from $0.86 to $0.24. The DSMAC adjuster is increased from $0.51 to $1.71.

APS June 25, 2009 letter

EXHIBIT
RUCO-4
ADMITTED

EXHIBIT A

ESTIMATED IMPACTS TO SETTLEMENT REVENUE LEVELS OF DIFFERING SCHEDULE 3 SCENARIOS FOR SINGLE RESIDENTIAL CUSTOMER LINE EXTENSIONS

	2010	2011	2012
Settlement with the modifications to Schedule 3 referenced therein.	$ 0	$ 0	$ 0
Scenario 1 – 1,000 ft free if under $25,000. Full amount paid if over $25,000.[1]	$5,960,000	$6,850,000	$10,000,000
Scenario 2 – Free footage if under $5,000/$10,000 (as applicable). Full amount paid if over $5,000/$10,000 (as applicable).			
50 ft. – up to $5,000	$ 580,000	$ 660,000	$ 960,000
100 ft. – up to $5,000	$ 600,000	$ 680,000	$ 990,000
500 ft. – up to $10,000	$ 2,760,000	$3,140,000	$ 4,550,000
750 ft. – up to $10,000	$ 2,800,000	$3,190,000	$ 4,600,000
Scenario 3 – Free footage approach subject to an investment cap.			
50 ft. but not more than $5,000	$ 2,600,000	$ 2,960,000	$ 4,280,000
100 ft. but not more than $5,000	$ 2,640,000	$ 3,000,000	$ 4,330,000
500 ft. but not more than $10,000	$ 4,815,000	$ 5,460,000	$ 7,850,000
750 ft. but not more than $10,000	$ 5,125,000	$ 5,800,000	$ 8,300,000
Scenario 4 - $5,000 equipment allowance.	$ 3,470,000	$3,860,000	$ 5,450,000

[1] This is the same line extension policy in existence prior to July 2007. Once an individual applicant's project exceeded $25,000 in estimated costs, it was no longer eligible for any free footage allowance regardless of the length of the extension.

EXHIBIT
RUCO-5
ADMITTED

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-08-0172

DIRECT TESTIMONY
IN SUPPORT OF SETTLEMENT AGREEMENT

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 1, 2009

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1

2 TESTIMONY

3 OF BEN JOHNSON, PH.D.

4 On Behalf of

5 The Residential Utility Consumer Office

6 Before the

7 Arizona Corporation Commission

8

9 Docket No. 01345A-08-0172

10

11

12 **Introduction**

13

14 **Q. Would you please state your name and address?**

15 A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

16

17 **Q. What is your present occupation?**

18 A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic

19 research firm specializing in public utility regulation.

20

21 **Q. Are you the same Ben Johnson that filed revenue requirements testimony on December 19,**

22 **2008, and rate design testimony on January 9, 2009 in this proceeding?**

23 A. Yes.

Q. What is your purpose in providing this testimony?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with this proceeding. The purpose of my testimony is to describe various aspects of the settlement agreement that has been negotiated by Arizona Public Service Company's (APS), RUCO and various other parties, to discuss various factors that were considered by RUCO during the negotiation process, and to help explain some of the reasons why RUCO believes the agreement is in the public interest and should be approved by the Commission.

Background

Q. To provide some context, can you briefly discuss the background of this proceeding leading up to the settlement agreement?

A. Yes. APS' initial application for a rate increase was filed with the Commission on March 24, 2008. During the next few months several parties were allowed to intervene. On June 2, 2008, APS filed an Amended Application seeking a gross increase in rates of $448.2 million (including fuel-related increases). In responsive testimony filed in December 2008, Staff proposed a total rate increase of approximately $307 million, while RUCO proposed a total rate increase of about half that amount.

On June 6, 2008, APS filed a Motion for Approval of Interim Rates, requesting an interim rate increase of approximately $115 million. On December 24, 2008, the Commission granted APS interim rates in the amount of $65.2 million.

APS filed a notice of settlement discussions on January 23, 2009. The parties began settlement discussions shortly thereafter. On March 5, the Hearing Division suspended the procedural schedule to provide additional time for these discussions to continue. Procedural conferences were held on April 7 and April 21, 2009. At the April 21 conference it was announced that the parties had reached an agreement in principle on revenue requirement issues. On May 4, 2009, the Settling Parties filed a Term Sheet outlining that agreement in principle. A procedural order was issued on May 11, 2009 establishing deadlines for filing testimony concerning the settlement agreement, and setting an evidentiary hearing for August 19, 2009.

Q. Can you please briefly describe the settlement negotiations?

A. Yes. The settlement negotiations were open to all parties to this proceeding, and throughout the process there was very active participation by a most of these parties. Meetings were typically held at the Commission's offices in Phoenix and were well attended. For instance, during most of the meetings, APS, Staff and RUCO were each represented by their attorneys as well as various staff members and subject matter experts. Arrangements were made to allow participation in all of the meetings by telephone conference calls; this allowed Ralph Smith (on behalf of the Staff) and myself, as well as various parties who were not physically located in Arizona, to actively and cost-effectively participate in the negotiations.

Meetings were scheduled as frequently as two or three times per week, stretching over a period of almost 5 months. Numerous issues were discussed during the negotiations, initially focusing on the overall magnitude and timing of any potential increases in rates, but eventually expanding to encompass numerous other issues, including essentially all of the issues raised by

the parties in their direct testimony concerning both revenue requirements and rate design, as well as certain other issues that extended beyond the scope of those filings (e.g. Palo Verde depreciation).

Many of these issues were highly complex and the parties entered the negotiations with widely varying perspectives on the appropriate resolution of these issues; further complicating matters, many of the issues were directly or indirectly interrelated with other issues. Additional complexity was introduced by the fact that there were so many different participants, and an effort was made to reach a global settlement that was acceptable to as many participants as possible.

The fact that each party had a unique perspective, and that some issues (and sub-issues) were more important to some parties than to others, made things more time consuming and complex, but it also opened up opportunities for trying to find creative solutions to the issues – not just trying to find a middle ground between the positions filed by the parties in their testimony, but in some cases going "outside the box" to craft solutions that were acceptable to all concerned, and were believed to be in the broad public interest.

Q. Why did RUCO and other parties invest so much time and effort in these negotiations?

A. As indicated by the lengthy duration of the negotiations, it was not easy to reach agreement amongst so many different parties. There was a great deal of "give and take" during this process, but there was also a strong awareness that the final product of the negotiating process needed to be in the general public interest, since it would be submitted to the Commission for its review and approval. Realizing that any proposed settlement would be subjected to close scrutiny, the parties strived to achieve a global settlement of all the disputed issues, they tried to

find solutions to these issues that were satisfactory to as many parties as possible, and they also sought solutions that were not only acceptable to the parties represented in the room, but were also believed to be in the broad public interest, and thus would hopefully be acceptable to the Commission.

When viewed from the perspective of RUCO or any other individual party, the proposed settlement agreement is not exactly what that party would prefer seeing emerge from a fully litigated proceeding. However, RUCO and the other parties recognized that decisions in a fully litigated rate proceeding rarely conform to the preferences of any one party, and they recognized that compromises reached through good faith negotiations had the potential for better achieving their respective top priorities and more successfully advancing the broad public interest than whatever decision would emerge from litigation – particularly in a complex case like this, where there are so many parties pursuing so many different issues. A litigated resolution is heavily influenced by various attributes and limitations of the litigation process, including time and resource constraints, tactical mistakes during the litigation process, and other factors which make the result of the process unpredictable, and can easily lead to results which are less than satisfactory for all concerned. Given this background, it is easier to understand why so much time and effort was invested in the negotiation process, and why the signatories feel that the proposed agreement is in their interest and the public interest and why it should be approved by the Commission. RUCO and other signatories support the agreement notwithstanding the fact that it resolves various issues in a manner which is inconsistent with the recommendations they initially submitted in their direct testimony.

Key Features of the Settlement Agreement

Q. Can you briefly highlight some of the key provisions of the proposed settlement agreement from RUCO's perspective?

A. Yes. For the sake of brevity and expediency, I will not discuss every provision in the agreement. Rather, I will focus on a few of the provisions that are particularly important to RUCO in carrying out its responsibilities on behalf of residential ratepayers.

While my discussion is intentionally brief and selective, a failure to mention other provisions should not be interpreted as an indication that RUCO considers those provisions to be unimportant or insignificant. While each of the parties had different priorities during the negotiation process, it is important to recognize that the settlement represents a balanced compromise reflecting the differing priorities of many different parties. RUCO supports the agreement in its entirety, and urges the Commission to adopt all of the provisions of the agreement without modification, even if certain provisions are not a major priority for RUCO, because all of the provisions were important to reaching a global settlement of the case – one that is satisfactory to all of the parties to the agreement.

Section II of the settlement includes a "General Rate Case Filing Plan" which provides that APS will not file its next two rate cases before June 1, 2011 and June 1, 2013, respectively. Further, new base rates cannot become effective before July 1, 2012.

Section III of the settlement agreement provides that the interim rate increase approved by the Commission will not be subject to refund. The agreement further provides for an additional non-fuel Base Rate increase of $131.1 million, a revenue increase of $11.2 million associated with establishing new base fuel levels, and encompasses an increase of $137.2

million to recover base fuel costs. The total revenue increase under the agreement is $344.7 million, inclusive of the interim increase and those portions of the rate increase which have previously been recovered through the Power Supply Adjustor.

Section VII of the agreement requires APS to reduce its expenses by an average annual basis of $30 million per year over a 5 year period beginning in 2010. The total expense reduction shall be a minimum of $150 million, and no annual reduction shall be less than $25 million.

Section VIII of the agreement requires APS to make certain financial commitments. First, the Company must provide additional equity of no less than $700 million by December 31, 2014. Second, the Company commits to using its best efforts to maintain investment grade financial ratios and to improve its financial ratings with the rating agency community. Third, APS will strive to achieve a capital structure with no more than 52% debt/total capital, as calculated by the credit rating agencies, by December 31, 2012.

Section X of the proposed agreement modifies the treatment of Schedule 3 (line extension) proceeds. Currently, line extension fees are recorded as Contributions in Aid of Construction (CIAC). The agreement allows APS to record these proceeds as revenue from January 1, 2010 to either December 31, 2012 or the conclusion of the Company's next general rate case, whichever occurs first. Section X also requires APS to withdraw its Impact Fee and System Facilities Charge proposals.

Section XI of the agreement allows APS to adjust depreciation rates for its Palo Verde plant to be consistent with the Palo Verde license extension the Company is seeking to receive from the Nuclear Regulatory Commission. The decreased depreciation expenses will go into effect when the license extension is approved, or January 1, 2012, whichever is later, and the benefit of these lowered expenses will be flowed through to customers at the time new base

rates next become effective – most likely in July 2012, or shortly thereafter.

Section XII provides incentives for the Company to limit Executive compensation to test year levels, and to strive to achieve the performance measurements set forth in Section XIII. The latter section establishes specific operational and financial performance measurements for APS, relating to energy efficiency, expense reductions, capital structure improvements and other important goals. The agreement includes detailed reporting requirements which obligate APS to provide information to the Commission regarding these issues. As well, Section XIII ensures that an independent third party (selected by Staff) shall conduct a benchmarking analysis of APS' operational and cost performance, relative to a comparable group of at least 30 other investor-owned electric-only utilities.

Section XIV of the agreement establishes new energy efficiency goals, calling for energy savings of 1.0% 1.25% and 1.5% for the years 2010, 2011 and 2012, respectively.

Section XVII of the proposed agreement provides that the increased revenues allowed or confirmed by the settlement will be applied on an equal percentage basis to all rate schedules.

Section XX of the agreement requires APS to make additional demand response commitments, including a new residential critical peak pricing rate program to be offered on a pilot basis.

Settlement Rate Increase

Q. How does the revenue increase included in the proposed settlement compare to the level of revenues recommended by the parties in their previously filed direct testimony?

A. The $345 million increase included in the settlement is less than the amount requested by APS,

but more than the amount recommended by RUCO, Staff and AECC. As summarized in the table in paragraph 3.8 of the agreement, APS originally requested an increase of $448 million. RUCO recommended against any further increase beyond the $170 million or so that had already been accomplished through the Power Supply Adjustor, while Staff and AECC recommended increases of $307 and $347 million, respectively. The revenue increase included in the settlement is significantly more than what RUCO recommended, as set forth in my direct testimony, but it is less than $50 million higher than the amounts recommended by the Staff and AECC, and it is more than $100 million lower than the amount requested by APS.

Q. Can you help explain why RUCO agreed to a settlement that provides a rate increase that is so much greater than you recommended?

A. Yes. Although there were many factors that influenced RUCO's decision to the settlement, I will focus on three of those factors.

First, RUCO considered the litigation risks associated with these issues. These litigation risks were of greater than normal concern in this particular instance, because of the complexity of the issues (involving numerous different adjustments), and the fact that both the Staff and AECC had filed testimony with recommendations accepting many of the Company's proposed post-test year adjustments. In my direct testimony, I explained RUCO's objections to these sorts of "attrition" related adjustments as follows:

> In the Company's filing, it proposes a mish-mash of different adjustments, calculated as of different dates. No overarching principle has been put forward to justify the particular mix of adjustments and calculation dates, and the end result deviates greatly from the Company's actual operating experience during the test year....
>
> The Company has proposed an ad hoc mixture of adjustments with no consistency to the dates used for the various adjustments, and no

> consistency in determining the scope of each adjustment...
> my general approach has been to start with a specific cut-off date, [the end of the test year] and then to remove all of the attrition-related adjustments that are inconsistent with that cut-off date.

If these issues had been fully litigated, I would have emphasized the theoretical and conceptual advantages of using a "pure" historical test year, with fewer mismatches and greater internal consistency. However, as a practical matter, it seemed unlikely that this "purist" viewpoint would ultimately prevail in this case – particularly since APS, Staff, and AECC were all using a "mish-mash of different adjustments, calculated as of different dates." The Staff accepted this approach with considerable reluctance, because of the current extraordinary circumstances, but regardless of the reason, RUCO essentially stood alone in recommending use of a more consistent or "pure" approach to developing the revenue requirement in this case.

Under these circumstances, there seemed to be a significant chance that RUCO might ultimately fail to prevail on these issues. Furthermore, there was no way to predict the outcome – the final result adopted by the Commission would presumably be whatever emerged from the litigation process. No one at RUCO could predict the outcome of that litigation process in advance, since it would partly depend on the outcome of events during the hearing process.

Thus, during the negotiation process RUCO did not view the choice as being between its direct testimony and whatever result emerged from the give and take of negotiation. Rather, the choice was between whatever result emerged from the negotiating process and the result that would emerge from the litigation process. However, the negotiation result was always clearly in view (and was being influenced by RUCO), whereas the possible litigation result was uncertain and unpredictable. To adapt a cliché – RUCO compared a bird in the hand to the possibility of two in the bush, but it was very much aware of the fact that under the current circumstances the odds were against capturing at least one of the birds in the bush.

Second, RUCO concluded that the unusual current economic circumstances when combined with APS' less-than-ideal financial condition, created an extraordinary situation which justified softening its stance with respect to deviations from the historical test year. This is consistent with the rationale given by the Commission in explaining why it granted interim rate relief in this case, and the rationale given in the Staff's direct testimony, explaining why it accepted so many of the Company's proposed post-test year adjustments. This is also consistent the following comments in my direct testimony, in which I recognized that the current unique circumstances might justify some deviation from the Commission's normal past practices:

> While RUCO is not recommending any other attrition compensation, to the extent the Commission concludes that additional compensation is warranted by the unique circumstances of this case, particularly the weak status of APS' credit metrics, a reasonable approach to calculating that compensation is set forth in the appendix to my testimony.

Third, RUCO viewed the settlement as a negotiated package. While RUCO accepted a revenue increase that was larger than it originally advocated, the Company accepted an increase that was less than it originally requested, and it accepted many other provisions and obligations which will advance the public interest – provisions and obligations that might not be imposed in a fully litigated proceeding.

Accordingly, I recommend that the Commission evaluate the settlement agreement as a whole, including concessions and commitments made by APS that go beyond anything that was recommended by RUCO or other parties in their direct testimony, including commitments to strengthen APS' financial metrics, commitments concerning the timing of future rate cases, and commitments relating to performance measures, a benchmarking study, executive compensation, renewable energy sources and energy efficiency. With the settlement, residential customers know what to expect from APS over the next few years, and they will receive the benefit of

additional commitments and assurances that might not otherwise be attainable.

Q. Couldn't the Commission accept the portions of the settlement which it finds most appealing, while rejecting other provisions?

A. The Commission might have the legal right to do so, but I do not think it would be wise to follow a "chinese menu" approach in reviewing the settlement agreement. In this case, where the settlement is so comprehensive both with respect to the issues and the parties, it would be preferable for the Commission to evaluate the agreement in its entirety, rather than evaluating the attractiveness of individual provisions. Among other problems, a "chinese menu" approach would have a very unfortunate chilling effect on future settlement negotiations. Public Utilities will be less willing to negotiate in good faith if they are fearful that concessions they make might be used against them in the Commission's final order, without their receiving the offsetting benefit of concessions made by RUCO and other intervenors during the negotiating process.

Q. Are there specific additional provisions that particularly influenced RUCO's decision to accept the settlement rate increase?

A. Yes. RUCO took into consideration several closely related provisions, including the equity infusion and capital structure commitments included in Section VIII; the timing of future rates cases described in Section II; and the cost cutting commitments included in Section VII. And, of course, RUCO was aware of other provisions in the agreement, relating to energy efficiency, performance measures, reporting requirements, benchmarking, and many other issues, that also advance the public interest.

Extraordinary Financial and Economic Events

Q. You have alluded to extraordinary events in the financial markets and the overall economy. Before explaining their relevance to RUCO's view of the settlement, can you please describe the events in question, and provide evidentiary support for your interpretation of these events, as well as their relevance to the agreement?

A. Yes. During the months leading up to the negotiations, and continuing through the period in which the agreement was being negotiated we have recently seen extraordinary events occurring in the financial markets and the broader economy. With the benefit of hindsight, these unusual events can be traced back to 2007, as the upward trend in home prices stalled, and troubles in the financial sector became increasingly apparent.

By January 22, 2008, Bank of America and Wachovia reported dramatic declines in their earnings, with 4th quarter earnings that were down 95% and 98%, respectively from the prior year. Both companies attributed this dismal performance to disruptions in the capital markets and the slowing economy. On March 17, 2008 Bear Stearns was acquired by JP Morgan Chase, under pressure from and with the assistance of the federal government. The Federal Reserve provided extraordinary financial support for the transaction; immediately prior to this "shotgun marriage", Bear Stearns' stock price had dropped from $172 to $2, as weaknesses in its balance sheet became increasingly apparent, and investors began to question the firm's viability.

Over the course of the following months, other indications of trouble emerged. For instance, on April 14, 2008, Wachovia announced a $393 million first-quarter loss and a 41% cut to its dividend, and indicated that it would need to raise $7 billion in capital. Similarly, on

June 9, 2008, Lehman Brothers Holdings announced that it would report a quarterly loss of nearly $3 billion, the first loss since the company went public. But during this period most observers assumed these were isolated incidents involving specific, limited problems involving particular firms; very few realized the extent to which a bubble in home prices had occurred, or that it would lead to a financial "panic" reminsicent of the one that occurred in 1929.

The first really strong indication that the problems might be serious enough to adversely threaten the entire economy occurred on September 7, 2008, when the US Treasury bailed out Government-sponsored but privately owned mortgage companies Freddie Mac and Fannie Mae in an attempt to avoid a collapse of the housing market. While in some ways a subtle change (making previously implicit assurances of federal support for these firm's debt increasingly explicit), in other ways this was an extremely significant event. Over the prior decade, these publicly traded, profit-making firms' "book of business" (their assets plus the mortgage securities they've guaranteed) had grown to a total of about $5.2 trillion, which was nearly as large as the entire $5.3 trillion of external debt then owed by the US Government. While this bailout was probably unavoidable under the circumstances at the time, it didn't end the financial and housing crisis, nor did it bring an end to federal bailout attempts on the scale of tens of billions, and even hundreds of billions, of dollars.

A week later, on September 15, 2008 Lehman announced that it had filed Chapter 11 bankruptcy - at the time the largest bankruptcy in U.S. history. The next day, on September 16, 2008, the Federal Reserve agreed to an $85 billion bailout of troubled insurance giant AIG.

On October 3, 2008, the Federal Government announced a $700 billion Troubled Asset Relief Program for the purchase of "troubled" bank assets. But, even this extraordinary program was not the end of the line. On November 25, 2008, the Federal Reserve announced an additional $800 billion package intended to help support the financial sector of the economy.

Meanwhile, these extraordinary bailout efforts were accompanied by an extraordinary easing of monetary policy, as the Federal Reserve began slashing short term interest rates and expanding the money supply in an attempt to avert panic and increase liquidity. By December 16, 2008, the benchmark Fed rate had been cut to near zero.

While the downturn and related government bailout efforts started in the housing and financial sectors, the problems quickly engulfed the manufacturing sector as well. Quarterly sales of the "all manufacturing" group tracked by the U.S. Census Bureau and the Federal Trade Commission declined by 11.1% and 22.1% during the 4th quarter of 2008 and first quarter of 2009, in sharp contrast with increases at annualized rates of 11.6%, 13.2% and 9.8% in the first three quarters of 2008.

The impact on the entire economy can be vividly seen in the U.S. Gross Domestic Product (GDP), which increased at annualized rates of .9% and 2.8% respectively, during the first two quarters of 2008, extending a pattern of strong economic growth which began in 2003. Conditions softened in the third quarter, when GDP fell at an annual rate of .5%, then turned sharply worse in the 4th quarter of 2008, when GDP declined at a 6.3% annual rate. News of this sharp downturn was officially confirmed while the settlement negotiations were underway, and the downturn continued during the negotiations. Current estimates indicate that GDP was declining at an annual rate of about 5.5% during the first quarter of 2009, despite near-zero short term interest rate, a multi-trillion dollar expansion of the Federal Reserve's balance sheet, and other extraordinary attempts at propping up the economy.

On December 19, 2008 the US Government's bailout efforts expanded beyond the financial sector, as it decided to pump $17.4 billion into GM and Chrysler in hopes of preventing the collapse of these industrial giants. During the first quarter of 2009, while the settlement negotiations were underway, it became increasingly clear that this initial $17.4 billion taxpayer

bailout might not be sufficient to save these firms. GM subsequently reported a 1st quarter 2009 loss of $6 billion, following on the heels of a $31 billion annual loss during 2008. And, on April 30, 2009, Chrysler filed for chapter 11 bankruptcy, with devastating consequences for bond holders and other debtors. On June 1, 2009, GM followed suit by also filing for bankruptcy protection. As this is written, it remains unclear how much money the US Government will eventually pump into these firms, or to what effect, and it remains uncertain how far the economy will decline, or how long the recession will last.

Q. What has occurred in the national labor market during this time period?

A. Labor conditions have deteriorated as problems that initially emerged in specific market sectors and geographic areas have gradually expanded into larger areas and more sectors of the economy. In January 2008, the national unemployment rate stood at just 4.9%. Unemployment had climbed slightly to 5.1% by March 2008, increasing to 5.8% in July 2008. Then, as the financial crisis and federal bailout efforts began to dominate the headlines, the rate of unemployment began to escalate. By January 2009 the national unemployment rate had reached 7.6%, and conditions continued to deteriorate throughout the negotiations. By April 2009, when an agreement in principal was announced, the unemployment rate had reached 8.9% and the end was not in sight. As this testimony was written, the most recent data available was for May, 2009 when unemployment had increased to 9.4%.

Q. How has the housing market performed during this period?

A. In January, 2008 there were 1,083,000 new housing starts, as reported by the Census Bureau. While the bubble in housing prices began to burst in some markets during 2007, nationally the

housing market was slow to react to the shift from a pattern of ever-increasing housing prices to one of stagnation or decline. In fact, during June, 2008 new housing starts nationwide remained at about the same level as six months earlier – 1,078,000, or less than half the prior peak of 2,273,000 which occurred near the peak of the housing price bubble, in January 2006.

As housing prices slumped, mortage lenders became increasingly risk averse, foreclosures escalated and potential home buyers became more cautious. As conditions in the financial sector deteriorated and news of government bailout efforts hit the headlines, the housing sector went into a sharp decline, with falling housing prices spreading to more and more parts of the country. As a result, housing starts began dropping rapidly, falling to a low of 454,000 in April, 2009 before edging up to 532,000 in May 2009 – roughly half the level of the prior year, and less than one fourth the level experienced during the 2006 peak.

Q. How has the stock market reacted to these extraordinary events?

A. The Dow Jones Industrial Average stood at 13,044 at the beginning of 2008, just modestly below a new all-time high that was reached a few months earlier. By September and October of 2008, as financial markets tightened and fears of a deep recession began to spread, the Dow plunged below 9,000, then began fluctuating wildly. The Dow finished the year off its November low, but it was still down 36 percent – its worst annual performance since the Great Depression.

As the new year started, optimism was spreading that perhaps the worst was over and a bottom had formed. However, by February 2009, it starting dropping again. The market continued to drop sharply during the early stages of the negotiations, decisively breaking through the prior year-lows and falling all the way to a new low of 6,594 on March 5, 2009. Not

only had the market failed its "test" of the lows experienced in November 2008, the Dow breached the psychologically important 7,000 level – a level last experienced in 1997.

Because the Dow had declined more than 50% relative to its level at the beginning of 2008, some observers suggested at least a temporary correction was overdue, while others argued the worst might finally be over and the bottom had finally been reached. While many of the classic signs of a market bottom were missing, market psychology improved, and the market rallied sharply during the remainder of March and April. By the time an agreement in principal was announced in late April, the Dow was again trading above 8,000.

The recent rally has certainly been positive, with the Dow trading in the vicinity of 8,500 as this was written in late June, 2009. It remains to be seen whether the bear market has actually ended, or the recent upward movement in prices has been a classic "bear market rally" (lulling investors into thinking the worst is over, before inflicting more pain).

Q. How have interest rates and the credit markets behaved during this time period?

A. In January, 2008, yields on 3 month treasuries were 2.82%. By June of 2008, short term yields had dropped to 1.89%, as the economy slowed and monetary policy eased. Then, in response to further deterioration in the economy and a resulting lessening of credit demand, as well as the massive easing of monetary policy, short term rates plummeted, with yields on 3 month treasuries declining to essentially zero by December, 2008. More recently, 3 month treasuries were yielding just 0.18% in May, 2009.

Although long term interest rates have not moved in synch with short term rates, they have also experienced some dramatic changes. In January, 2008, yields on 30 year Treasury bonds were 4.33%. In June of 2008, long term yields had actually increased slightly, to 4.69%,

1 despite the gradual weakening of the economy. But, as the financial crisis and federal bailouts
2 began to dominate the headlines, investors became increasingly worried about all forms of risk,
3 which made US Government debt increasingly attractive, relative to other, riskier options.
4 Yields on 30 year Treasury bonds plummeted to 2.87% in December 2008, before investors
5 pulled back, as they became increasingly nervous about the long term inflationary implications
6 of recent monetary and fiscal policy. By May, 2009, yields on 30 year Treasury bonds had
7 moved back up to 4.23%.

8 Interest rates on corporate bonds have also fluctuated widely over the past 18 months, at
9 least partly in response to large shifts in attitudes toward risk. Aaa rated corporate bonds were
10 yielding 5.33% in January, 2008, or approximately 1% more than the corresponding yield on
11 Treasury bonds. At the end of 2008, these low risk corporate bonds were yielding 5.05%, just
12 slightly lower than when the year began, whereas Treasury bond yields had declined sharply.
13 As a result, the lowest risk corporate bonds were yielding nearly 2.2% higher than the
14 corresponding yield on Treasury bonds. Since Aaa corporate bonds are normally viewed as
15 being only one notch more risky than Treasury bonds, this unusually large gap suggests the
16 "flight to quality" that temporarily benefited Treasury bonds did not fully extend to even the
17 highest quality corporate bonds.

18 The market for higher risk corporate bonds has been even more volatile and unfavorable.
19 Yields on Baa corporate bonds were 6.54% in January, 2008, representing a premium of 1.21%
20 relative to Aaa bonds, or about 2.21% relative to Treasury bonds. Toward the end of 2008, fears
21 of further collapse of the financial system scared investors away from higher risk alternatives,
22 pushing Treasury yields sharply lower, while the yield on Baa bonds moved in the other
23 direction, climbing to 8.43%. The result was an extraordinary large gap of 3.38% between Baa
24 and Aaa bond yields in December 2008, and an even more extreme gap of 5.56% between Baa

bonds and Treasury bonds.

During the settlement negotiations, this "flight to quality" receded somewhat, as risk premiums began to return to more normal levels. By May, 2009, Aaa yields were 5.54%, which was 1.31% higher than the corresponding yield on Treasury bonds – still slightly elevated compared to the premium of about 1% experienced throughout the first six months of 2008.

Ominously, however, lesser rated corporate debt did not improve to the same degree. Baa yields declined somewhat, as investors became somewhat more willing to take risks, but they did not return to the more normal levels experienced during the first half of 2008. In April 2009, when the agreement in principal was announced, the Baa yield was 8.39%, which was far in excess of the 6.97% level of the same month in 2008, and of even greater concern, this implied a risk premium of 3.00% relative to Aaa bonds and 4.63% relative to Treasury bonds – roughly double the May 2008 risk premiums of 1.42% and 2.53%, respectively.

Q. How is this review of recent financial and economic data relevant to RUCO's decision to support the settlement?

A. The settlement negotiations involved a utility that has been earning substantially less than its allowed rate of return and that has a relatively weak credit rating. Moreover, these negotiations occurred during a period of extraordinary uncertainty for the economy and financial markets – a period in which investors have been unusually risk averse. This was (and is) a period when the downside consequences of financial missteps have loomed larger than normal, as evidenced by the collapse, near-collapse, and/or government bailout of such iconic firms as Lehman Brothers, AIG, Bank of America, Citigroup, Merrill Lynch, Chrysler, General Motors and others.

During the negotiations it became increasingly clear that there was no way to be sure

how deep the current recession will be, how long it will last, or what its full implications will be for financial markets, the energy markets, the Arizona economy, or APS specifically. There is no way of knowing whether credit markets will soon return to normal, whether market conditions will remain poor, or whether they will further worsen. If the recession proves to be deeper, or more long lasting than most market participants currently anticipate, or if risk aversion intensifies even further, the adverse implications for APS and its customers could be quite severe, particularly if APS were to lose its investment grade bond rating.

Under these extraordinary circumstances, RUCO concluded that it would not be prudent to continue to insist upon strict reliance on a historical test year with minimal post-test year adjustments. Consistent with this shift in priorities, RUCO decided that the interests of residential customers would best be advanced by pushing APS to strengthen its financial metrics, and to take extraordinary steps to protect APS' investment grade bond rating, even if this might require somewhat higher electric rates in the short term. RUCO concluded that the downside risks of losing the bond rating, or losing access to credit markets on favorable terms during these turbulent times outweighed any benefits that might be gained from lower rates during the short term.

Succinctly stated, these extraordinary economic and financial conditions in combination with APS' marginal financial metrics led RUCO to accept a rate increase that was substantially larger than I originally recommended. RUCO believes residential customers will be better served by accepting the rate increase called for by the settlement, because this significantly reduces the risk of losing APS' investment grade bond rating at a particularly inopportune time – when financial markets are unusually jittery and firms with less than stellar credit risk losing access to capital markets.

Attrition

Q. Can you clarify how current economic conditions relate to the attrition issue, and how the attrition issue relates to the settlement rate increase?

A. Yes. In its direct testimony, the Company contends that it has underearned by $321 million from 2003-2007, and projects an additional shortfall of at least $380 million will occur through 2010 under present conditions. As I explained in my direct testimony, there is no expectation that earnings will exactly match the allowed rate of return. However, such a substantial level of under-earning occurring over a prolonged period is troubling. As I explained in Appendix B attached to my direct testimony, the phenomenon of a utility's profitability eroding over time is referred to as "attrition". A variety of factors can contribute to attrition, including changes in the utility's revenues, expenses and investment. If growth in investment and growth in expenses outpaces growth in revenues, attrition will occur.

In most cases attrition is attributed to one or more of the following: inflation; growth in capital investment per KWH or per customer; and, regulatory lag (which delays recovery of cost increases). Typically, inflationary pressures outstrip the benefits of increasing economies of scale, technological progress and increasing operating efficiency. Assuming the utility is allowed to pass fuel and purchased power cost increases through to consumers, the most likely circumstance in which a utility might experience continued erosion of its profitability (attrition) is when the utility is investing substantial amounts in additional plant and equipment with higher unit costs than its existing facilities – assuming the adverse impact of inflation on these new investments outweighs the beneficial impact of increased economies of scale that often accompanies such growth.

In Appendix B to my direct testimony I concluded that APS has been suffering from "mild" attrition, and that attrition was expected to continue. My conclusions were based upon an examination of historical and projected financial and operating data for the years 2005-2010. In developing my estimates, I focused my attention on the 2005-2007 time period, with a more limited consideration of the partly projected 2005-2010 time period, and the longer 1997-2007 historical time period. I also noted that the Commission may want to consider a larger amount of attrition compensation than was implied by the data from this time period, if it wanted to further strengthen the Company's financial position.

During the settlement negotiations, as I have explained, RUCO shifted its focus away from the 2007 test year and began to place greater emphasis on current 2009 and near-future (2010-2014) financial and economic conditions. During this shift in focus, it became increasingly apparent that the relatively mild rate of attrition that had been experienced over the 2005-2007 time period might worsen over the next few years.

The current unusual economic conditions, particularly the collapse of housing prices, reduction in stock market values, and increase in unemployment, result in increased uncertainties concerning the current and near-future rate of attrition. Given the factors that contribute to attrition, and the specific problem of continuing high levels of investment without concomittant revenue growth, there was reason to be concerned that a relatively mild attrition problem might have become something much more serious.

While the long term population trends favoring migration into states like Florida and Arizona are unlikely to suddenly reverse course, there is greater-than-normal uncertainty concerning the rate of migration into APS' service territory during the next few years. Baby boomers may decide to postpone their retirements in response to losses in their 401Ks; working people may decide to move to the Sun Belt in hopes of finding a job – or they may decide to

stay where they are until housing prices stabilize and labor market conditions improve.

All that can be said with any confidence at the moment is that there is a great deal of uncertainty concerning near-term growth rates. Yet, APS must continue to invest to maintain reliability and to accommodate growth that has already occurred, and to some extent it needs to continue to invest in anticipation of the resumption of growth which will presumably occur at some point in the future. Until revenue growth materializes, APS faces the need to finance investments without an immediate influx of revenues from new customers. Hence, this is a time of unusual uncertainty concerning the rate of attrition.

Bond Ratings and Credit Metrics

Q. You've alluded to APS' bond ratings as one of the factors considered by RUCO. For the convenience of the Commission, can you please briefly summarize the key facts supporting this aspect of your analysis?

A. Yes. APS credit ratings are BBB-, Baa2, and BBB by S&P, Moody's and Fitch, respectively. APS is rated on the lowest tier of "investment grade" credit by S&P, it is rated only 1 notch higher by Moody's and Fitch, and the Company's credit metrics provide little reason to hope that this situation will improve anytime soon. The weak rating is partly due to the fact that APS has generated relatively weak earnings, and partly due to the fact that APS has long term purchased power contracts which are interpreted by the credit rating agencies in a similar manner to debt.

As a result, some of the quantitative credit metrics are borderline for continuation of its existing, relatively weak, bond rating. APS claims that if the Commission does not grant

adequate and timely relief, "the Company's credit metrics will reach non-investment grade by the end of 2009, which could result in a credit downgrade with devastating financial results to both APS and its customers." [Brant Direct Testimony, p. 37]

Q. To what extent do the rating agencies focus on financial performance in evaluating credit ratings?

A. The rating agencies consider the interaction of business and financial risk, together with actual financial performance (credit metrics) during the ratings process. The S&P rating agency analyzes financial risk both qualitatively and quantitatively, "mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP." [Attachment DEB-4, p. 12] S&P provides the following indicative financial risk ratios for U.S. utilities:

	Cash Flow		Debt Leverage
	FFO/Debt (%)	**FFO/Interest (x)**	**Total Debt/Capital (%)**
Modest	40-60	4.0-6.0	25-40
Intermediate	25-45	3.0-4.5	35-50
Aggressive	10-30	2.0-3.5	45-60
Highly Leveraged	Below 15	2.5 or less	Over 50

Source: Attachment DEB-4, p. 12

Q. Where does APS fall on this matrix?

A. As I explained in my direct testimony, according to S&P's June 25, 2008 report, APS' "Funds From Operations" (FFO)/Debt ratio is 16%, FFO/Interest ratio is 4, and debt to total capital is 57% [S&P Ratings Direct, June 25, 2008; APS13070, p. 2] APS' FFO/Debt ratio is particularly

problematic, placing the Company just barely above the "highly leveraged" category. The rate increase called for in the settlement will increase the numerator of this ratio, helping to move the Company toward a more favorable category for this metric. However, the 57% debt ratio still places APS near the unfavorable end of the range for the "Aggressive" financial risk category. As I will explain below, under the settlement agreement, APS is committed to taking steps to improve both its FFO/Debt and its debt/toal capital ratio as measured by the rating agencies. These steps should help move the Company away from the "Aggressive" or "Highly Leveraged" categories, toward the less risky "Intermediate" category.

Q. What would be the effect of a downgrade of APS' bond ratings?

A. APS' ratings are currently toward the low end of the industry range, and any substantial further degradation could put the Company into one of the "junk" bond categories. The most obvious reason for concern is the impact of any further downgrading on the interest rates which would be paid by the Company when it needs to raise additional debt capital. As ratings decrease, the required interest on new issuances increases. These increased debt costs lead to higher costs for customers over the life cycle of the debt issuance (typically 20 years). However, as I explained in my direct testimony, the risk associated with a downgrade go beyond measurable differences in interest rates. At a time when financial markets continue to be unusually jittery, there is some risk (however remote) that a further deterioration in APS' financial metrics could make it very difficult, if not impossible, for APS to acquire the funds it needs to finance its construction program.

Q. Can you further elaborate on how bond ratings relate to the settlement?

A. Both stock and bond market conditions continue to be unfavorable for firms needing to raise capital. This is particularly true for firms with Baa and lower bond ratings that may need additional debt financing. There is uncertainty regarding how long these problems will persist or whether financial market conditions will improve or worsen over the next few years. There is also a possibility that the rating agencies will tighten the requirements for maintaining an investment grade bond rating, either de facto or de jure. Such a tightening could plausibly emerge during the next few years, as the bond rating agencies react to rising defaults, increased government scrutiny of their ratings, and ongoing criticism of their failure to adequately warn against the risks which triggered the recent financial crisis and massive government bailout efforts. Needless to say, while this risk may be somewhat remote, it is nevertheless significant in this case, because APS has an ongoing need to access the credit markets, and it cannot simply place its construction program on hold until market conditions improve.

During a financial crisis or tight credit environment, even firms with an investment grade bond rating may find it more difficult than normal to issue additional debt or equity. Having a bond rating toward the low end of the utility industry, the Company may find it difficult to fully fund its planned capital construction program – bearing in mind that merely offering to pay higher than normal interest rates wouldn't necessarily solve the problem, since the very need to offer such high rates could be perceived as a sign of weakness, pushing away more risk-averse investors and making it harder to raise capital in the future. For instance, the FFO/interest ratio will further deteriorate if APS is required to pay higher interest rates on new issuances – a phenomena which is indicative of the increased default risks to bond holders when a firm is under pressure to keep borrowing even during unfavorable credit conditions.

Were it to lose the ability to access the debt market at attractive rates, APS would be left with relatively limited and unattractive options. It could stop paying dividends (which would effectively force Pinnacle West to do the same thing), and attempt to meet its financing needs entirely through internally generated cash flow. It could slow, or halt, all but the most urgently needed construction projects, but if this were to continue for very long, it could result in a reduction in service reliability, or require extraordinary measures to maintain reliability, such as rolling brownouts during peak hours, or a temporary moratorium on new service connections in order to constrain demand to fit within the capabilities of the system.

Q. Can you explain the equity infusion described in section VIII ?

A. The financial metrics relied upon by rating agencies that are most problematic for APS are the Total Debt/Capital ratio and the FFO/Debt ratio. Both of these ratios can be improved by reducing the Company's imputed debt levels, as measured by the rating agencies. The $700 million equity infusion is one of the steps APS has committed to take in order to improve these metrics and strengthen its bond rating.

In this regard, it is important to realize that the credit agencies impute other obligations to the debt category when calculating APS' capital structure, in addition to the debt amounts reported by APS on its balance sheet and used in financing its rate base. These imputed amounts generally arise out of long term legal obligations, such as the Palo Verde lease-back arrangement and long term purchase power agreements, which have many of the characteristics as long term debt. Because the rating agencies view these long term contractual obligations as being like debt, they view APS as being highly leveraged. Standard and Poor's states:

> We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases) [See, Staff Attachment RCS-2]

APS' imputed debt is also the denominator of the FFO/debt ratio, which is solidly in the "Aggressive" category, and just barely above the "Highly Leveraged" category.

The settlement includes provisions that will reduce the level of imputed debt and increase the level of funds from operations, thereby improving both the numerator and the denominator of the FFO/debt ratio. For instance, the rate increase will improve the numerator, while the equity infusions will improve the denominator. Section VIII requires APS to provide additional equity of no less than $700 million by December 31, 2014; it also requires APS to strive to maintain investment grade financial ratios and improve its financial ratings with the rating agency community; and, to attempt to achieve a capital structure with no more than 52% debt/total capital, as calculated by the credit rating agencies, by December 31, 2012.

All of these provisions are inter-related, and tend to reinforce each other. Probably the most significant provision is the one committing APS to attempt to reduce its debt/total capital from the current level of around 57% to 52%, which will also improve the FFO/debt ratio.

Timing of Future Rate Cases

Q. Can you explain the provisions concerning the timing of various rate increases?

A. Yes. Section II of the settlement provides that APS' will not file its next two rate cases before June 1, 2011 and June 1, 2013, respectively. Section II also provides that new base rates cannot

1 become effective before July 1, 2012. The first provision is particularly significant, since it
2 ensures that the substantial rate increase included in the agreement is not immediately followed
3 by another rate increase request.

4 At a minimum these provisions ensure that the Staff, RUCO and other parties are given a
5 "breather" of a year or more, during which they won't need to be concerned with any APS rate
6 cases, and can instead focus on other priorities. Similarly, these provisions provide customers
7 with a greater degree of stability and predictability concerning electric rates over the next few
8 years. While it's never pleasant to contemplate a rate increase, at least customers are being given
9 plenty of advance notice, and thus they can better plan their household budgets, evaluate options
10 for more energy efficient appliances, and so forth.

11 Since there is no way to know how quickly APS would file any future rate cases, or
12 whether the Commission would accept an immediate refiling, it is difficult to evaluate the full
13 impact of these provisions. But, APS would likely file rate cases as quickly and as frequently as
14 feasible, absent this provision. It certainly could be argued that a new rate case should not be
15 filed before new rates have gone into effect for some reasonable minimum period of time. But,
16 I am not aware of any administrative rule or statutory requirement that would prevent APS from
17 filing a new rate case as quickly as possible after the existing case is resolved. Absent this
18 provision or some other legal impediment, APS could potentially file its next rate case within 30
19 days after receiving a decision in this case, forcing the Commission to decide whether or not to
20 accept such a filing.

21 If a decision in this case were issued in October or November 2009, APS could
22 conceivably file a new case in late 2009 or early 2010. This contrasts with Section II of the
23 agreement, which specifies that the next case will not be filed before June 1, 2011 (roughly 18
24 months later). Hence, it is fair to say that this portion of the agreement not only reduces

uncertainty but it also benefits the parties and customers by ensuring that APS "stays out" for a significantly longer period than might otherwise occur.

Cost Cutting

Q. Can you explain the benefits of the cost cutting commitments included in Section VII?

A. Yes. Section VII requires APS to reduce its expenses by an average annual basis of $30 million per year over a 5 year period beginning in 2010. The total expense reduction shall be a minimum of $150 million. Finally, no annual reduction shall be less than $25 million. These cost reductions will benefit customers by reducing the Company's future revenue requirement, thereby reducing the need for, and magnitude of, any future rate increases. As well, these cost reductions will increase the numerator of APS' FFO/debt ratio, helping to maintain or improve APS' bond rating.

Cost control and increased efficiency is particularly important during a challenging economic environment like the current one. In a competitive industry during times like these, the strongest, best managed firms find ways to cut costs and maintain their financial viability despite challenging market conditions; less well managed firms often go bankrupt, or lose ground competitively. Needless to say, it is impossible to directly simulate these sorts of competitive pressures in a regulated monopoly environment. The threat of bankruptcy is obviously not the best way to pressure management, labor unions, or others to cut costs and increase efficiency when the firm is providing a vital public service like electricity. However, this provision serves to increase the pressure to make difficult decisions in order to cut costs and

improve efficiency – the same sort of external pressure which arises in competitive industries during an economic recession. This sort of pressure can push management into making difficult decisions like choosing which employees to keep and which to let go, or to negotiate other concessions from unions which would otherwise seem just too painful to attempt, or to negotiate better pricing from suppliers or to find new suppliers if the existing ones won't cooperate.

Performance Measures, Reporting and Benchmarking

Q. Can you briefly explain the performance measures, reporting requirements and benchmarking provisions contained in Section XIII?

A. Section XIII of the agreement establishes certain priorities, in the form of operational and financial goals for APS. These include maintaining and improving its financial strength, encouraging energy efficiency, increasing reliance on renewable energy, and reducing operating expenses. As well, Section XIII provides a practical administrative framework to assist the Commission and other parties in periodically evaluating APS' progress toward achieving these goals.

More specifically, APS has agreed to periodically provide reports with detailed information regarding customer service, reliability, safety and financial operations, and it APS has agreed to finance a benchmarking analysis that will provide valuable information that the Commission and the parties can use to assist them in evaluating how well APS is performing relative to other utilities. The benchmarking analysis will be performed by an independent third party selected by the Staff; and it will provide detailed information comparing APS' operational

and cost performance relative to a peer group of at least 30 other investor-owned electric-only utilities – firms with characteristics that are reasonably comparable to those of APS with respect to total revenue, number of customers, nuclear generation, ownership of generation, customer density, customer growth and fuel and resource mix.

Other Settlement Provisions

Q. What other provisions of the Agreement would you like to discuss?

A. I would like to briefly discuss: the Palo Verde depreciation changes contained in Section XI; the modified treatment of Schedule 3 proceeds contained in Section X; the Section XVII provisions regarding the spread of the rate increase across rate schedules; and, the demand response commitments included in Section XX.

Q. Can you explain the Palo Verde depreciation changes contained in Section XI?

A. Yes. These provisions allows APS to adjust depreciation rates for its Palo Verde plant to be consistent with the Palo Verde license extension the Company hopes to receive from the Nuclear Regulatory Commission (NRC).

The plant is being depreciated based on the duration of its existing license. However, there are no physical or technical constraints that would preclude the possibility of using the plant for longer than its original license. Hence, the Company is asking the NRC for a license extension. If the license extension were granted but depreciation rates were not reduced, the plant would be fully depreciated sometime around the end of its existing license term, and thus

it would have a zero net cost on the balance sheet and in rate base from that point forward. Under standard accounting rules, however, depreciation rates should appropriately be reduced if the license extension is granted, to ensure that the cost of the plant is spread over its entire life cycle. As well, by modifying the depreciation rates, inter-generational equity is improved, by ensuring that customers in the later years of the plant's life make some contribution to the cost of the plant, rather than receiving a "free ride."

The key issue dealt with in the settlement agreement is the timing of the depreciation change, which will go into effect on the date when the NRC approves the Palo Verde license extension, but not earlier than January 1, 2012 . Absent this provision, there is no way to predict when APS would file for a depreciation rate change, or when the Commission might authorize such a change. Under the terms of the agreement, the new depreciation rates will probably go into effect during 2012, at a time when the next rate case will likely be under review by the Commission. Aside from clarifying what might otherwise be a contentious issue, the main benefit of this provision is to provide APS with a short term boost to its 2012 earnings per share (and earned return on equity). Because the depreciation change will improve APS' earnings, this provision reduced the uncertainties concerning this issue for APS, making it easier for APS to accept a delay in the next rate case until no earlier than June 1, 2012, as set forth in Section II.

Q. Can you please elaborate on the potential impact of this provision on APS, its customers and stockholders?

A. Yes. This provision will potentially boost APS' earnings per share during 2012 without having any immediate adverse impact on customers. In effect, APS' earnings per share may be temporarily increased without requiring customers to pay higher rates. This logically follows

because depreciation is a non-cash accounting entry. Hence, this provision doesn't have any immediate impact on the amount of cash being paid by customers to APS. As well, it has no impact on APS' cash flow or its cash-related financial metrics, such as the FFO/Debt ratio. That isn't to say that the provision is unimportant. By clarifying the timing of this anticipated accounting change, this provision eliminates one of the uncertainties facing APS, making it easier to reach agreement on the rate case scheduling provisions in Section II.

There is one other effect worth noting: due to this provision, accumulated depreciation may be slightly lower in future rate cases than it might otherwise be. Lower annual Palo Verde related depreciation charges will reduce accumulated depreciation, which in turn will increase net plant and APS' rate base in future years. Any impact to customers (and benefit to APS) in future rate cases will be determined by the rate of return times the difference in rate base amount, scaled up for income tax effects. The extent of this impact, if any, would depend on when APS might otherwise have filed for a depreciation rate change, and when any such filing would otherwise go into effect (be approved by the Commission). If this provision does result in a slightly lower balance for accumulated depreciation in the 2011 and subsequent rate cases, it will, in turn, result in slightly higher rates for customers and thus provide somewhat higher earnings and cash flows to APS and its stockholder in future years.

Parenthetically, I would also note that if the life extension is granted, the cost of shutting down the plant will be deferred further into the future. In turn, this will eventually result in a reduction in the Systems Benefit Charge, which will further benefit customers. However, this issue will be handled by the Commission in a future proceeding, and is not resolved by the settlement agreement.

Q. Can you now explain Section X of the Agreement, relating to Schedule 3 (line extension) proceeds?

A. Yes. Currently, line extension fees are recorded as CIAC. Section X of the proposed agreement modifies the treatment of these funds by allowing APS to temporarily record these proceeds as revenue. This temporary accounting treatment will boost APS' earnings per share during 2012 without having any immediate impact on the amount of cash flowing from customers to the Company. In turn, this will increase net plant and APS' rate base in future years. The impact on customers (and benefit to APS) in future rate cases will be determined by the rate of return times the difference in rate base amount, scaled up for income tax effects. This provision was included in the agreement in an effort to close the gap between the respective parties positions on certain issues, and was particularly helpful in reaching agreement on the rate case scheduling provisions in Section II, because it will improve APS' earnings per share and return on equity during 2012. The magnitude of this impact will depend on the amount of Schedule 3 payments received during 2012, which in turn will depend on the extent to which in-migration and customer growth have begun to accelerate by that time.

Q. **Can you briefly explain Section XVII of the Agreement, concerning the Revenue Spread?**

A. Yes. Section XVII of the proposed agreement resolves the revenue spread issue using a highly simplified approach. It provides that each retail rate schedule will receive an equal percentage total base rate increase, inclusive of the interim rate increase, and inclusive of fuel and purchased power costs that are incorporated into base rates.

Q. Finally, can you please comment on Section XX of the Agreement, particularly with regard to Critical Peak Pricing?

A. Yes. Section XX of the agreement includes several noteworthy provisions. It not only calls for approval of a new demand response super peak time-of-use rate for residential customers, as proposed by APS in the direct testimony of Charles Miessner, but it also calls for the creation of a new residential critical peak pricing (CPP) pilot program. The CPP rate is intended to provide participating customers with strong, clear price signals that are narrowly focused on a limited number of specific hours of each year. The agreement calls for APS to provide participating customers with notice of each critical peak period, via email, text message or telephone message, at least 6 hours in advance of the commencement of each critical peak period. This will ensure that participating customers have an opportunity to adjust their thermostats, avoid running their dishwasher or doing their laundry, or take other actions to reduce their load during the peak time period.

There is no reason to believe that a CPP approach won't be successful with residential customers. In the case of both commercial and residential customers, opportunities exist for customers to respond to narrowly focused, timely price signals. By testing this concept with both General Service and residential customers, the Company will more quickly gain experience with the CPP approach – and it is quite possible that the CPP approach will actually be more popular with residential customers than with business customers.

Q. Does this conclude your testimony concerning the settlement agreement, which was prefiled on July 1, 2009?

A. Yes.