0000102933

Transcript Exhibit(s)

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

Exhibit # : S7-S18, WRA1-WRA3, P1-P4, P9-P12, ZWICK1, ZWICK2

RECEIVED
2009 SEP 22 P 1: 58
AZ CORP COMMISSION
DOCKET CONTROL

DOCKETED
DOCKETED BY

EXHIBIT
S-7
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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 RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01345A-08-0172

DIRECT

SUPPLEMENTAL TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JANUARY 9, 2009

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. ADJUSTMENTS TO NET OPERATING INCOME 2

C-20 DSM Estimated Future Lost Revenue Pro Forma 2

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph Smith who previously filed direct testimony in this proceeding?

A. Yes.

Q. What did your direct testimony state concerning Demand Side Management ("DSM")?

A. My direct testimony at page 11 stated that:

> "The impacts of Staff's recommendations on the recovery mechanism for Demand Side Management ("DSM") related costs are not yet known and will be addressed by a Staff witness who will present testimony concerning this item in the rate design filing."

Q. How is Staff addressing issues related to DSM at this time?

A. I address an Arizona Public Service Company ("APS") proposed adjustment no. 13. Staff witness Frank Radigan also addresses this issue in his rate design testimony.

II. ADJUSTMENTS TO NET OPERATING INCOME

C-20 DSM Estimated Future Lost Revenue Pro Forma

Q. What has APS proposed as an adjustment to net operating income for DSM and estimated future net lost revenue?

A. As shown on APS witness Ewen's Attachment PME-13 and described in his direct testimony at page 33, APS proposes to reduce test year operating revenue by $16.789 million for 220,696 MWh of lost sales, and to reduce related operating expenses by $1.052 million, for a net reduction to pre-tax operating income of $15.738 million. As explained by Mr. Ewen at page 33 of his testimony:

> "The Company will experience a loss in revenue due to a reduction in customer usage as these [DSM] programs are implemented and become successful. The expected usage reduction from the implementation of programs in 2010 will be approximately 220,696 MWh. The resulting revenue loss is calculated by multiplying the Test Year revenue in cents/kWh, less the Test Year fuel cost in cents/kWh, by these expected MWh reductions. The pre-tax operating revenue adjustment of $15.7 million resulting from these sales adjustments is set forth in the Uncollected Fixed Cost pro forma and is included as Attachment PME-13 and is in SFR Schedule C-2, on page 5, column 13."

Q. Was a similar adjustment proposed by APS and rejected by the Commission in APS' last rate case?

A. Yes. In Docket No. E-01345A-05-0816 et al, APS had proposed a pro forma adjustment for estimated 2006 lost revenues from DSM programs in conjunction with a test year end September 30, 2005, i.e., approximately 1.25 years beyond the test year. In the current case, APS has proposed a pro forma adjustment for estimated 2010 lost revenue from DSM programs in conjunction with a 2007 test year, i.e., three years beyond the test year. As stated on page 30 of Decision No. 69663:

> APS proposed a Demand Side Management ("DSM") adjustment ... to reduce TY revenues by $4,907,000 to reflect Commission

> approved DSM programs. Both Staff and RUCO objected to the pro-forma $4,907,000 revenue adjustment, which reflects a "net lost revenue" or "conservation" adjustment.

As stated on page 31 of Decision No. 69663:

> We agree with Staff and RUCO that APS' pro-forma conservation, or net lost revenue, adjustment to increase (sic) revenues should not be adopted. As testified to by Staff, a mechanism exists for APS to recover a portion of the actual energy efficiency savings from its successful DSM programs. We also agree that neither the adjustment nor its amount is sufficiently known and measurable to reasonably change the cost of service. Further, under the terms of the Settlement Agreement as approved by the Commission, APS is not allowed to recover net lost revenues in this case on a going forward basis.

Q. What is the approximate impact on the revenue requirement?

A. The approximate impact from APS' proposed adjustment no. 13 to the revenue requirement is $15.7 million.

Q. Did Staff make this adjustment in its direct testimony?

A. No. Staff did not make the adjustment because Staff is willing to give APS the opportunity to provide a rational for why Staff should support this recommendation.

Q. How does Staff intend to update this adjustment?

A. Unless APS provides a compelling argument for this adjustment, including a strong argument why a conclusion different than Decision No. 69663 is required, Staff will reverse APS proposed adjust no. 13 when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

ALL-STATE LEGAL®
EXHIBIT
S-8
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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 RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01345A-08-0172

DIRECT

TESTIMONY

ON THE ISSUES OF REVENUE ALLOCAITON

AND RATE DESIGN

OF

FRANK W. RADIGAN

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JANUARY 9, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

COST OF SERVICE AND REVENUE ALLOCATION 6

RESIDENTIAL RATE SCHEDULES 17

GENERAL SERVICE RATE SCHEDULES 21

CANCELLING PARTIAL REQUIREMENTS RATE SCHEDULES 23

SOLAR POWER AND GREEN POWER MODIFICATIONS 24

DEMAND RESPONSE PROGRAMS 26

Super Peak TOU Pricing 28

Critical Peak Pricing 29

OTHER RATE MODIFICATIONS 31

TRANSMISSION COST ADJUSTMENT 34

OTHER TARIFF MODIFICATIONS 35

ATTACHMENTS

APS Response to Staff Discovery Request 22.7 ..... Exhibit (FWR-2)

Table Showing Staff and Company Proposed Revenue Allocation ..... Exhibit (FWR-3)

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

Based on the improvements in rates of return between the Cost of Service study presented in APS last rate case and this rate case, the numerous changes in rate offerings as well as the numerous rate design changes proposed by the Company in this case, Staff recommends that the APS Cost of Service study not be used as the primary basis for revenue allocation. Instead, the revenue increase should be allocated among rate classes on an equal percentage basis.

With respect to specific schedules, the Company is proposing to freeze the "Series 1" Time-Of-Use ("TOU") rates, *i.e.*, Schedules ET-1 and ECT-1R. Staff supports this for residential customers. This will encourage APS customers to choose either the Company's current "Series 2" TOU rates (ET-2 and ECT-2) or the Company's new proposed ET-SP (Residential Service Time Advantage Super Peak Rate). The "Series 2" TOU rates have a shorter on-peak period than the "Series 1" TOU Rates, the purpose of which is to incent customers to move more load to the off-peak period. The "Series 2" rates been shown to be more effective than the "Series 1" rates in encouraging customers to shift load to off-peak periods, and this shift should be encouraged.

APS is also proposing to modify E-12 (Residential Service – Standard Rate) to include the addition of a fourth and higher priced block rate for customer consumption greater than 3,000 kWh monthly. The intent is to encourage large E-12 customers to both conserve energy and switch to TOU. Staff supports this change because the fourth block is targeted at the largest users (those who could do the most with respect to energy conservation).

APS proposes to increase all Residential Basic Service Charges in order to collect a larger portion of fixed costs through non-energy rates. Some of these increases are large, and could result in rate shock. Therefore, Staff recommends that no Basic Service Charge be increased by more than twice the overall average increase.

The Company is proposing to retain the current discounts for the low-income rate schedules (E-3 and E-4). In these tough economic times, any increase in rates is difficult, but this is especially true for those customers that take service under the support schedules. Staff recommend's that customers on rate schedules E-3 and E-4 maintain their current rates, such that the low-income customers who qualify for electric service under those rates are held harmless from the rate increase. Any revenue shortfall resulting from this recommendation should be recovered from all other rate schedules, in a manner similar to how the overall revenue increase is spread. This result would have a very limited impact on other customers. In addition, Staff recommends that the PSA continue to not apply to low-income customers.

The Company proposes to disaggregate Schedule E-32 (General Service) and E-32 TOU (General Service TOU) into four new rate schedules and to cancel partial requirement rate schedules E-32R (General Service – Partial Requirements Service), E-51 (Classified Service - Partial Requirements Service to Qualified Co-generators greater than 100 kW), and E-55 (Classified Service – Partial Requirements Service to 3,000 kW or greater). The General Service rate schedules are being disaggregated into four new service schedules so as to better price the cost to serve. The partial requirement rate schedules are currently frozen and the

services provided under these rate schedules are now covered by Schedules E-56 (Classified Service – Partial Requirements Service) and SC-S (Classified Service – Partial Requirements Solar). These proposals are cost based, reasonable consistent with Decision No. 69663 (June 28, 2007), and the Commission should adopt them.

The Company proposes to freeze Rate Schedule Solar-2 – the rate class where the Company owns and installs a solar power system when it is uneconomic for the customer to install a system on their own. The Company is proposing to freeze the rate because it has outlived its usefulness. Staff supports this change because there are now many more options for customers to purchase solar power systems as opposed to buying them from the Company.

The Company proposes to offer customers two new options for purchasing various percentages (10% and 35%) of their total energy needs through solar power. This supplements the current options provided by Schedule Solar-3 of 100% and 50%. The Company also proposes to provide customers with increased flexibility by allowing them to combine the purchase of power under Schedule Solar-3 with Green Power Block ("GPS-1") and Green Power Percentage ("GPS-2"). The added flexibility of lowering the purchase requirement levels and by combining the solar program with other green power programs is commendable and should be supports.

The Company proposes to add a new Super Peak TOU rate schedule. The Super Peak TOU option has a seven hour on-peak period but adds a super peak price for weekday afternoons from 3 p.m. to 6 p.m. during June, July and August. This option is yet another means to reduce load during the critical peak period. The Company's existing TOU rate options have been effective in encouraging customers to move load to off-peak periods. The Super Peak TOU option, however, incents the customer to a few select hours during the Company's peak months. This Super Peak TOU could prove to be an even more effective tool than the existing TOU rate schedules.

The Company also proposes to add a new Critical Peak Pricing ("CPP") program. This is another positive step to control peak load. It is targeted to customers that can most likely shed load; it provides an adequate discount to encourage participation; and, it is limited in scope so that it can be controlled, evaluated, and improved before it is offered to all customers. Staff believes that there are two improvements, however, that should be made to the program. First, to successfully test how customers react to the need for a demand response, one must have actual data. Staff would therefore change the tariff language to state that the Company will invoke a <u>minimum</u> of 6 CPP Events and a maximum of 18 CPP Events per calendar year. Second, the Company's proposal to limit participation to 100 is too low given that it is proposing to offer the program to seven different service classes. Staff recommends that the number of participants be increased to 200.

The Company proposes to modify the Environmental Improvement Surcharge ("EIS") to reduce regulatory lag. This proposal should be rejected. The Company has presented the same arguments that it made in the last case, and the Commission has already ruled on the issue.

The Company proposes to modify the Transmission Cost Adjustor ("TCA") to operate as an automatic rate adjustor whenever FERC modifies the open access transmission rate. This proposal should also be rejected as unnecessary and unwarranted.

The Company seeks to modify Service Schedules 1, 4, 5, 8, 10 and 15 in a number of respects. These changes provide clarifications to existing provisions of the schedules. Therefore, Staff would recommend their adoption by the Commission.

In Staff witness Smith's accompanying supplemental testimony, he discusses an APS operating income adjustment related to Demand Side Management and estimated future net revenue losses that APS attributes to DSM. My testimony relates to the policy aspects of the DSM recovery mechanisms and describes how APS is compensated for performing DSM through a performance incentive mechanism that is designed to reward APS only when its DSM programs are successful and result in energy or demand savings.

INTRODUCTION

Q. Please state your name, position and business address.

A. Frank W. Radigan. I am a principal in the Hudson River Energy Company, a consulting firm providing services to the utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. Have you previously provided testimony in this proceeding?

A. Yes, Staff provided testimony on the issue of the Demand Side Management Adjustor Mechanism and the Impact Fee which was filed on December 19, 2008. That testimony summarized my qualifications and experience as well.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Commission?

A. Yes. I have testified before the Commission previously on three occasions. I testified before the Commission in the most recent UNS Electric, Inc. rate case (Docket No. E-04204A-06-0783), the most recent Tucson Electric Power Company rate case (Docket No. E-01933A-07-0402), and the most recent Southwest Gas Company rate case (Docket No. G-01551A-07-0504).

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address Staff's review of the Cost of Service study, the allocation of the revenue increase amongst service classes, the proposed rate design, and

proposed changes to various service schedules, including the proposed changes to the Environmental Improvement Surcharge and the Transmission Cost Adjustor.

Q. Could you please summarize your testimony?

A. Yes, based on the improvements in rates of return between the Cost of Service study presented in APS last rate case and this rate case, the numerous changes in rate offerings as well as the numerous rate design changes proposed by the Company in this case, Staff recommends that the APS Cost of Service study not be used as the primary basis for revenue allocation. Instead, the revenue increase should be allocated among rate classes on an equal percentage basis.

With respect to specific schedules, the Company is proposing to freeze the "Series 1" Time-Of-Use ("TOU") rates, *i.e.*, Schedules ET-1 and ECT-1R. Staff supports this proposal because it will encourage APS customers to choose either the Company's current "Series 2" TOU rates (ET-2 and ECT-2) or the Company's new proposed ET-SP (Residential Service Time Advantage Super Peak Rate). The "Series 2" TOU rates have a shorter on-peak period than the "Series 1" TOU Rates, the purpose of which is to incent customers to move more load to the off-peak period. The "Series 2" rates been shown to be more effective than the "Series 1" rates in encouraging customers to shift load to off-peak periods, and this shift should be encouraged.

APS is also proposing to modify E-12 (Residential Service – Standard Rate) to include the addition of a fourth and higher priced block rate for customer consumption greater than 3,000 kWh monthly. The intent is to encourage large E-12 customers to both conserve energy and switch to TOU. Staff supports this change because the fourth block is targeted at the largest users (those who could do the most with respect to energy conservation).

The Company is proposing to retain the current discounts for the low-income rate schedules (E-3 and E-4). In these tough economic times, any increase in rates is difficult, but this is especially true for those customers that take service under the low-income schedules. Staff recommends that customers on rate schedules E-3 and E-4 have their rates remain at current levels, such that the low-income customers who qualify for electric service under E-3 and E-4 are held harmless from the rate increase. Any revenue shortfall resulting from this recommendation should be recovered from all other rate schedules, in a manner similar to how the overall revenue increase is spread. This result would have a very limited impact on other customers.

The Company proposes to disaggregate Schedule E-32 (General Service) and E-32 TOU (General Service TOU) into four new rate schedules and to cancel partial requirement rate schedules E-32R (General Service – Partial Requirements Service), E-51 (Classified Service - Partial Requirements Service to Qualified Co-generators greater than 100 kW), and E-55 (Classified Service – Partial Requirements Service to 3,000 kW or greater). The General Service rate schedules are being disaggregated into four new service schedules so as to better price the cost to serve. The partial requirement rate schedules are currently frozen and the services provided under these rate schedules are now covered by Schedules E-56 (Classified Service – Partial Requirements Service) and SC-S (Classified Service – Partial Requirements Solar). These proposals are reasonable and consistent with Decision No. 69663 (June 28, 2007).

The Company proposes to freeze Rate Schedule Solar-2 – the rate class where the Company owns and installs a solar power system when it is uneconomic for the customer to install a system on its own. The Company is proposing to freeze the rate because it has

outlived its usefulness. Staff supports this change because there are options for customers to purchase solar power systems as opposed to buying them from the Company.

The Company proposes to offer customers two new options for purchasing various percentages (10% and 35%) of their total energy needs through solar power. This supplements the current options provided by Schedule Solar-3 of 100% and 50%. The Company also proposes to provide customers with increased flexibility by allowing them to combine the purchase of power under Schedule Solar-3 with Green Power Block ("GPS-1") and Green Power Percentage ("GPS-2"). The added flexibility of lowering the purchase requirement levels, and by combining the solar program with other green power programs, is commendable. Staff recommends the adoption of these changes.

The Company proposes to add a new Super Peak TOU rate schedule. The Super Peak TOU option has a seven hour on-peak period but adds a super peak price for weekday afternoons from 3 p.m. to 6 p.m. during June, July and August. This option is yet another means to reduce load during the critical peak period. The Company's existing TOU rate options have been effective in encouraging customers to move load to off-peak periods. The Super Peak TOU option, however, incents the customer to shift load during a few select hours in the Company's peak months. This Super Peak TOU could prove to be an even more effective tool than the existing TOU rate schedules.

The Company also proposes to add a new Critical Peak Pricing ("CPP") program. This is another positive step to control peak load. It is targeted to customers that can most likely shed load; it provides an adequate discount to encourage participation; and it is limited in scope so that it can be controlled, evaluated, and improved before it is offered to all customers. Staff believes that there are two improvements, however, that should be made

to the program. First, to successfully test how customers react to the need for a demand response, one must have actual data. Staff would therefore change the tariff language to state that the Company will invoke a minimum of 6 CPP Events and a maximum of 18 CPP Events per calendar year. Second, the Company's proposal to limit participation to 100 is too low given that it is proposing to offer the program to seven different service classes. Staff recommends that the number of participants be increased to 200.

The Company proposes to modify the Environmental Improvement Surcharge ("EIS") to reduce regulatory lag. This proposal should be rejected. The Company has presented the same arguments that it made in the last case, and the Commission has already ruled on the issue. The Commission set a fixed surcharge amount instead of adopting an adjustor mechanism.

The Company proposes to modify the Transmission Cost Adjustor ("TCA") to operate as an automatic rate adjustor whenever FERC modifies the open access transmission rate. Staff cannot support the proposal.

The Company seeks to modify Service Schedules 1, 4, 5, 8, 10 and 15 in a number of respects. These changes are generally minor and mostly provide clarifications to existing provisions of the schedules. Therefore, Staff would recommend their adoption by the Commission.

Finally, Staff discusses the rate design aspects of the Demand Side Management ("DSM") lost revenue recovery mechanism. As addressed in the supplemental testimony of Staff witness Ralph Smith, unless APS provides a compelling argument for its adjustment for lost revenue due to DSM, Staff will reverse APS' adjustment when Staff updates its

revenue requirement model at the time of Staff's surrebuttal filing. Utilities can be compensated in a variety of ways for performing DSM and this Company already has a compensation mechanism which was adopted as part of a comprehensive settlement.

COST OF SERVICE AND REVENUE ALLOCATION

Q. Could you please summarize APS' proposals with respect to its Cost of Service study and revenue allocation?

A. Yes, APS performed an embedded Cost of Service study using the twelve-month period ending September 30, 2007. (Rumolo Pre-Filed Testimony ("PFT"), page 14). APS did not perform a detailed marginal Cost of Service study. (Rumolo PFT, page 16). However, APS used marginal cost concepts to develop seasonal and time-of-use cost differentials. (Rumolo PFT, page 16). In performing the Cost of Service study, the Company analyzed costs by function, classified them as to cost causality, and allocated them by jurisdiction (Federal or State), service class, and rate schedule. (Rumolo PFT, pages 15-19).

In the last APS rate case, there was considerable disagreement between the parties about how to allocate the costs of owning and operating the generating plants and associated energy. Given that these costs are approximately 70% of total costs, the choice of allocation method will have a considerable impact on the Cost of Service results. In Decision No. 69663, the Commission directed APS to use an energy-weighted method to allocate production demand costs. (Decision No. 69663, page 71). In its Application the Company used the Average and Excess Demand ("AED") Method, which is a widely accepted energy allocation method. (Rumolo PFT, page 20). The AED method allocates a portion of production costs based on a customer class' peak demand contribution and then allocates the balance on that class' energy-based or average demand contribution. The

AED method recognizes that production facilities provide both demand and energy related functions.

Also in the last APS rate case, it was suggested that an hourly allocation method be used to allocate fuel and purchased power costs. (Decision No. 69663, page 71). The hourly energy allocation method examines customer class hourly load shapes and hourly energy prices to come up with a weighted energy cost. (Rumolo PFT, page 21). For example, a customer class that uses more of its energy during peak summer hours should be allocated higher average fuel and energy costs than a customer class whose energy consumption is more off peak.

Thus, the Company's Cost of Service study has used a widely accepted methodology to allocate production costs and has addressed the means to allocate energy costs to service classes as suggested by parties in the last case.

Q. What is typically the end result of a Cost of Service study, and how is it used in developing rates?

A. The end result of performing a Cost of Service study is to provide a rate of return for each customer class and to functionalize, classify, and allocate costs. The rate of return by class is helpful to determine if a service class is providing too little or too much in revenues. For example, if the General Service class has a rate of return of 12% and if the overall rate of return is 10%, then that service class should receive a smaller than average increase in rates. Dividing a class rate of return by the overall rate of return provides a Rate of Return Index ("ROR Index"), which is a helpful tool for comparing the rate of return for each service class with the overall rate of return. In the example above, the General Service Class would have an ROR index of 1.2 (12%/10%). While this provides a useful

benchmark for analyzing the Company's proposed rate class increases, it is only one factor the Commission should consider in setting rates.

Q. What were the results of APS' Cost of Service study?

A. The results of the Company's Cost of Service study, including the ROR index for each service class, are presented in the table below:

Service Class	Rate of Return	ROR Index
Residential	2.85%	0.75
General Service	5.04%	1.33
Water Pumping	6.92%	1.82
Street Lighting	-0.03%	-0.01
Dusk to Dawn	6.61%	1.74
Total	3.79%	1.00

Q. What did APS state concerning its application of those results?

A. Company witness Rumolo states that the Cost of Service study was a major input for designing the Company's proposed rates. (Rumolo PFT, page 15). When asked in discovery to explain how the results of the Cost of Service study were used to allocate rates, the Company responded that its proposed revenue allocation does not bring customer class rates completely in line with costs, but rather moves in that direction. In its response, the Company also provided a table that sets forth a comparison between the Cost of Service revenue deficiency for each rate class and the proposed revenue increase. The response and table are provided as Exhibit FWR-2.

Q. What does your analysis indicate?

A. A comparison of the results of the Cost of Service study and the Company's proposed revenue allocation shows that the Company did consider the results of its Cost of Service study, but only to a small degree. For example, given APS' overall requested increase of 16.99%, the Cost of Service study indicates that the General Service Class should receive an 11.6% increase, but the Company recommends that the class receive a 16.74% increase. For the Residential Service Class, the Cost of Service study indicates that the class should get a 21.7% increase, but the Company recommends that the class get a 17.27% increase. The disparity between the results of the Cost of Service study and the recommended revenue allocation does not stop at the service class level but also extends to individual rate schedules as well. For example, the Cost of Service study indicates that General Service Rate Schedule E-20 should receive a 54.3% increase, while the Company is recommending a 20.2% increase. For Residential Rate Schedule E-12, the Cost of Service study indicates that the class should receive a 9.5% increase, but the Company is recommending a 16.43% increase. (It should be noted that these differences are not due to the PSA revenue (fuel) component of the total 16.99% increase requested by APS).

Q. Has the Company indicated that it considered other objectives in its proposed revenue allocation besides the Cost of Service study results?

A. Yes, in its response to Staff data request 22.7, the Company explained that it considered other objectives in the revenue allocation process include preserving rate stability; avoiding rate shock for any rate class; reducing, but not eliminating, the return differential between General Service and Residential Revenue Classes; and preserving consistency between TOU rates and other rate options.

Q. Do you agree that other objectives should be considered in the revenue allocation process?

A. Yes, reviewing the results of the most recent Cost of Service study is just one of many considerations to be used when deciding how to allocate revenues. One should also look at how the Company is proposing to use the Cost of Service Study results, the results of past studies, and also changes being proposed in the rate schedule offerings and rate design.

Q. Has the Company made progress in moving rates closer to the rate of return index?

A. Yes. The table below shows the results of this Cost of Service study and the Cost of Service study from the last rate case (using the Company's proposed allocation method)[1].

	Last COSS		Current COSS	
Service Class	**Rate of Return**	**ROR Index**	**Rate of Return**	**ROR Index**
Residential	1.38%	0.53	2.85%	0.75
General Service	4.12%	1.59	5.04%	1.33
Water Pumping	3.72%	1.44	6.92%	1.82
Street Lighting	1.61%	0.62	-0.03%	-.01
Dusk to Dawn	5.28%	2.04	6.61%	1.74
Total	2.59%	1.00	3.79%	1.00

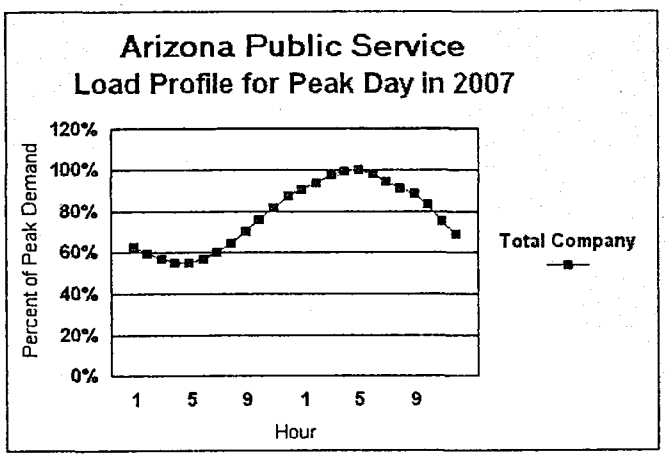
[1] The results of the Cost of Service study from the last APS rate case were taken from Docket No. E-01345A-05-0812 – APS Exhibit No. 70, Rumolo Rebuttal, p. 9, and Attachment DJR-IRB)

As can be seen, there has been a considerable shift in the ROR indices for most of the service classes with considerable movement for the Residential and General Service Classes. For the Residential Class, the ROR index went from 0.53 to 0.75, which indicates that its rate of return relative to the overall rate of return has improved sharply. For the General Service Class, the ROR index has decreased from 1.59 to 1.33, which indicates movement from a position of overpaying relative to the overall average rate of return. These changes could be the result of the revenue allocation adopted in the Company's last rate case or due to changing cost causality. For example, between 2004 (the test year in the last Cost of Service study and 2007, residential sales and revenues grew by 20% and 45%, respectively. This compares to total Company growth of 14% and an increase in revenues of 40%. While this growth may not totally explain the improvement in the ROR Index for the Residential Class, it cannot be denied that improvement did occur.

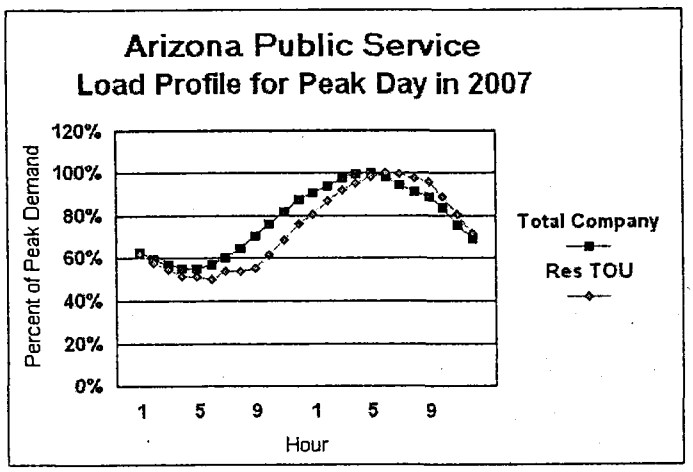
Q. Could you please explain the issue of how load shapes should be considered in the revenue allocation process?

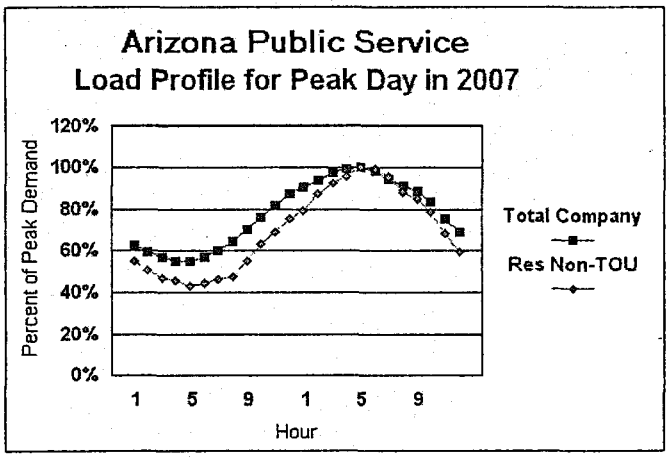
A. Yes. In response to a Staff discovery request, Staff obtained 2007 hourly load data for each rate schedule[2]. Based on the load data for the peak day (08/13/2007), Staff then developed load shapes for the Company as a whole and for each rate schedule. The graph below shows the load shape for the peak day in 2007. As can be seen, the Company peaked at 5 p.m. with a very pronounced peak.

[2] Responses to Staff 22.6 and 22.10 which are too voluminous for attachment.



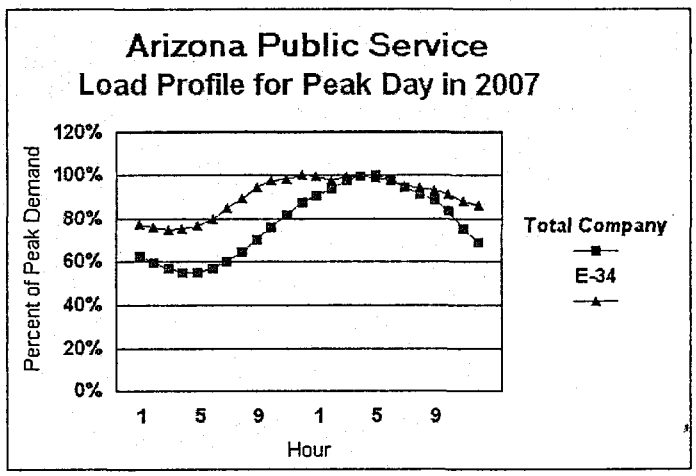
Comparing the load profile of individual rate schedules to the Company load profile is also a useful exercise when one tries to evaluate the effectiveness of the rate design offerings being made. The two graphs below show the load profiles of the residential TOU and the residential non-TOU rate schedules.

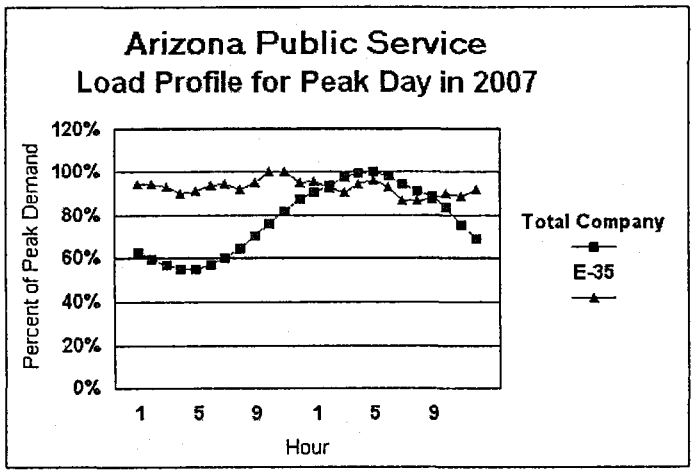




As can be seen from the graphs, the non-TOU customers peak when the Company overall load peaks and do so with an even more pronounced peak than the Total Company. The TOU customers also have a significant amount of load during the peak period, however, when one compares the load profile of the TOU customers to the non-TOU customers, it is clear that the TOU customers have reacted positively to the price signals and have moved load to the off-peak period.

As shown on the graphs below, this same reaction to price signals occurs for the General Service customers as evidenced by the load profiles of rate schedules E-34 (Extra Large General Service) and E-35 (Extra Large General Service TOU). The TOU rate schedules have moved a significant amount of load away from the peak period in response to price signals.





Q. Are there any other factors that should be considered in the review of the results of the Cost of Service study and the allocation of revenues?

A. Yes. The change in the rate offerings being made by the Company also needs to be considered.

Q. What changes is APS proposing and how should they be considered?

A. Two Residential rate schedules are being eliminated (Rate Schedules E-10 and EC-1) and these customers have to elect another rate schedule. The partial requirement rate schedules E-32R (General Service – Partial Requirements Service), E-51 (Classified Service - Partial Requirements Service to Qualified Cogenerators greater than 100 kW),

and E-55 (Classified Service – Partial Requirements Service to 3,000 kW or greater) are all being cancelled, and these customers will be moved to other rate schedules (E-56 and SC-S). The "Series 1" TOU rate schedules (ET-1 and ECT-1R) discussed previously are being frozen, and it is anticipated that these customers will migrate to other rate schedules. Together, these changes impact rate schedules that currently provide 31% of the Company's revenues. Customers subscribed to all of these schedules in the test year will react in some way to the cancellation and/or freezing of the schedules. Given the large amount of revenue involved, changing customer behavior could have a significant impact on the results of the Cost of Service study. In addition, the Company is proposing to disaggregate the E-32 (General Service) and E-32 TOU (General Service TOU) Rate Schedules into four new rate schedules. The customers under these rate schedules provide 40% of the current revenues. We do not know how these customers will react to the new rates that they will be paying. In summary, these significant changes in rate offerings could have a dramatic impact on the results of the Cost of Service study and indicate that it should not be exclusively relied upon as a means to allocate revenues in this case.

Q. What do you recommend?

A. After considering all of the factors discussed above, Staff recommends that any increase in revenues be allocated across the board on an equal percentage basis. As Staff will discuss in more detail below, Staff recommends that customers on Rate Schedules E-3 (Energy Support) and E-4 (Medical Equipment Support Program) receive no increase in rates. Any resulting revenue shortfall should be recovered from all other rate schedules on an equal percentage basis. Staff's proposed revenue allocation is shown on Exhibit FWR-3.

Q. Were there any exceptions to the recommended revenue allocation that you recommend besides the E-3 and E-4 rate schedules?

A. No, but there was a refinement. The Company has nine rate schedules that are tied to the E-32 (General Service) rate schedule. As noted in the testimony of Company Witness Delizio, the rates were not designed to adhere to strict Cost of Service but are necessarily tailored to the various rate schedules (Delizio PFT, pages 28-29). In other words he designed rates by customer size and voltage level first (i.e. by rate differential). Thus, the rates of the E-32 non-TOU rates are themselves tied together because of the rate differentials between voltage levels. The E-32 TOU rates were similarly designed. (Delizio PTF, page 32). As shown on Exhibit FWR-3, the Company's proposed revenue allocation is different for the individual rate schedules (e.g., E-32 > 401 kW rate schedules receives a 15.7%, while the increase for E-32 0-20 kW rate schedule receives an 18.7% increase).

The interrelationship of rate schedules presents an issue with respect to revenue allocation. If one applies an equal percentage increase to each rate schedule, the rate differentials between the voltages and customer sizes change. If one tries to keep the rate differentials between rate schedules, the percentage increase to each rate schedule changes. In my revenue allocation to the E-32 rate schedules, the directive by the Commission in Decision No. 69443 was to disaggregate into more service classes delineated by size. Thus, Staff felt keeping the rate differential was more important than keeping the percentage increase equal between rate schedules within E-32. The easiest way to do that was to make sure that as a group the E-32 General Service Class was given the same overall average increase as the Company and maintained rate differentials.

RESIDENTIAL RATE SCHEDULES

Q. Would you please give a summary of the existing Residential Rate Schedules that APS offers?

A. In the test year, APS had nine Residential Rate Schedules – four TOU rate schedules (Schedules ET-1, ECT-1R, ET-2, and ECT-2), one inclining block rate schedule (Schedule E-12), two rate schedules for special assistance (Schedule E-3 and Schedule E-4), and two rate schedules (E-10 and EC-1) that were eliminated by the Commission in Decision No. 69663.

For Schedules E-10 and EC-1, customers were given a one-year transition period, which expired on July 1, 2008, to select another rate. For rate design purposes, the Company has assumed that the E-10 customers all chose the E-12 rate and that the EC-1 customers all chose the ECT-1R rate schedule.

Q. What does the Company propose in this case with respect to residential rate offerings?

A. The Company proposes to freeze: the "Series 1" TOU rate schedules (Rate Schedule ET-1 and Rate Schedule ECT-1R) so that they will not be available to new customers or to existing customers who switch service locations. The "Series 2" TOU rate schedules (Rate Schedule ET-2 and Rate Schedule ECT-2) will serve as the primary TOU rate offerings. The Company believes that the "Series 2" TOU rates provide a better opportunity for customers to shift usage to the off-peak hours and, thereby, reduce their bills. (Delizio PFT, page 26).

The "Series 1" rates, ET-1 and ECT-1R, have a 12-hour on-peak period from 9 a.m. to 9 p.m. weekdays. In July 2006, APS introduced the "Series 2" rates, Schedules ET-2 and

ECT-2, to encourage customers to shift more load to the off-peak period, especially during the summer months. The "Series 2" rates have a 7-hour on-peak period from noon to 7:00 p.m. weekdays. In addition, the all-energy rate, Schedule ET-2, has a summer on-peak price that is four times as high as the off-peak price. The Company believes that the "Series 2" TOU rates, due to the shorter on-peak period (and longer lower price off-peak periods), provide a better opportunity for customers to shift usage to the off-peak hours and thereby reduce their bills. (Delizio PFT, page 26).

Company Witness Miessner also proposes to add a new Rate Schedule ET-SP. The proposed rate would be similar to rate ET-2, with a 7-hour on-peak period, but will add a Super Peak price for weekday afternoons from 3:00 p.m. to 6:00 p.m. during June, July and August. The summer off-peak price is discounted to off-set the higher Super Peak price. The customer has the opportunity to have lower monthly bills by reducing load during either the on-peak or Super-Peak periods, or both. (Miessner PFT, page 9).

If APS' proposed residential rate schedules were adopted, APS would have six rate offerings available to new customers: four standard rate offerings, E-12, ET-2, ECT-2 and ET-SP; and two low-income programs, E-3 and E-4.

Q. Please summarize other significant rate design issues being proposed.

A. In addition to the introduction of the Super Peak TOU rate, there are several other rate design changes being proposed by the Company. The Company is proposing a fourth block for E-12. This higher priced block rate is for customer consumption greater than 3,000 kWh per month. As explained by Company witness Delizio, the intent of this new block is to encourage energy conservation for the Company's largest residential users. The

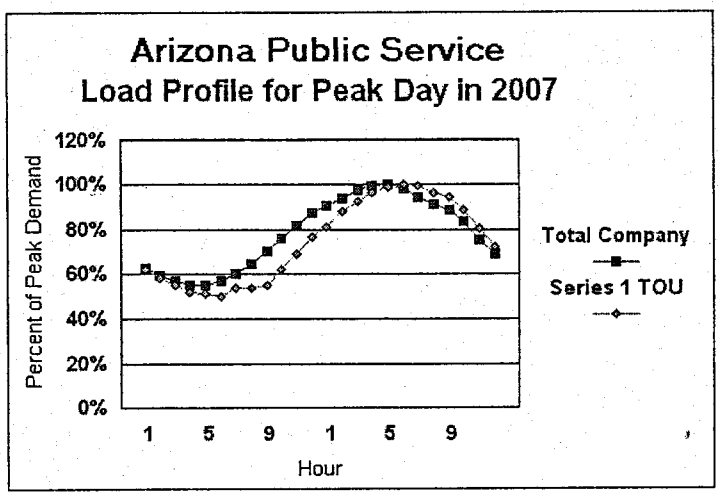
change would also provide an additional price incentive for such customers to switch to a TOU rate. (Delizio PFT, page 3).

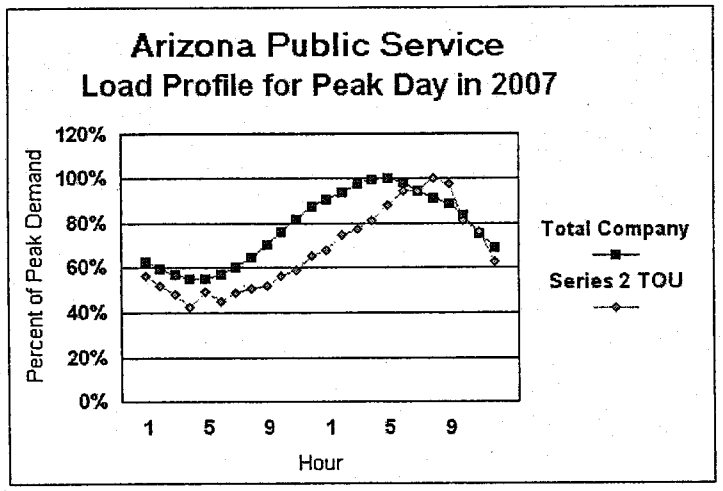
The Company also proposes to continue the discounts to the low-income rate schedules, E-3 and E-4.

The only other significant proposed rate design changes proposed are increases to the bundled Basic Service Charges for all Residential Rate Schedules between about 2¢ to about 9¢/day to better reflect the fixed costs associated with customer connection to APS' system. The increase of 2 ¢/day applies to all but the E-12 Rate Schedule and results in a 3.8% increase in the Basic Service Charge. The increase of 9 ¢/day for the E-12 Rate Schedule results in a 36% increase in the charge.

Q. Please comment on the Company's proposed changes to the rate schedules.

A. The majority of the proposed changes are reasonable and should be approved. The Company's proposed fourth block to E-12 and the new TOU rate offerings are a good step forward in providing customers with appropriate price signals. Although the current "Series 1" TOU rates have been somewhat effective in encouraging customers to shift to the off-peak period, the on-peak period for this series is excessively long. As evidenced by the graphs below, load research shows that rate structure for the "Series 2" TOU is more effective in encouraging customers to shift load away from the time of system peak. Thus, on a going forward basis, the "Series 2" TOU rates are the better choice.





Some changes proposed by the Company, however, do not go far enough. TOU rates and inclining block rates do not need to be separate offerings. In the recent Tucson Electric Power Case (Docket No. E-01933A-07-0402), the parties agreed to TOU rate offerings that also had inclining block rates. APS should be directed to file an inclining block rate schedule for all of its Residential TOU rate schedules.

In addition the Company is proposing to retain the current discounts for the low-income rate schedules (E-3 and E-4). In these tough economic times, any increase in rates is

difficult, but this is especially true for those customers that take service under these schedules. However, Staff recommends that all low-income customers retain their current rates. In addition, Staff recommends that the PSA continue to not apply to low-income customers.

The 36% increase in the E-12 Basic Service Charge proposed by APS should be rejected. While the proposed rate of $0.343 per day is less than the cost-based rate of approximately $0.50 per day, the rate impact is unacceptable, especially under Staff's proposed revenue increase. Staff proposes that the increase in the Basic Service Charge be limited to no more than twice the overall average increase (in this case, 19.42% for a basic service charge of $0.302 per day).

GENERAL SERVICE RATE SCHEDULES

Q. Would you please discuss the significant rate design changes that APS is proposing for the General Service Rate Schedules?

A. Yes. First, as an outcome of the Company's last rate case and as directed in Decision No. 69663, the Company is proposing to disaggregate rate schedule E-32 into several new rate schedules based on customer size. The Company proposes to replace the two size categories (Tier 1 (0-20 kW) and Tier 2 (greater than 20 kW)) with four sizes categories (E-32 XS (0-20 kW); E-32 S (21-100 kW); E-32 M (101-400 kW); and E-32 L (greater than 400 kW)). The proposed rate structure for E-32 XS would be similar to the current E-32 Tier 2 rate. The proposed rate structure for E-32 S, E-32 M, and E-32 L would be similar to the current E-32 greater than 20 kW rate. The Company believes that this modification will provide rates that are better tailored to the customers in these size categories, and will result in revenues that are more aligned with costs (Delizio PFT, page 28). This is a reasonable change. With increasing usage, the service size and voltage

level generally also increase. Accordingly, customer size is one good indicator of different usage characteristics and cost to serve.

Second, the Company currently offers several time-of-use rates for General Service and Water Pumping customers (Rate Schedule E-32 and Rate Schedule E-35). As explained by Company witness Delizio, the Company is proposing to disaggregate rate schedule E-32 TOU into several new rate schedules based on the same customer size categories proposed for Rate Schedule E-32. The current rate schedule E-32 TOU is separated into two size categories: Tier 1 (0-20 kW) and Tier 2 (greater than 20 kW). The proposed rate schedules will be divided into four size categories: E-32 TOU XS (0-20 kW); E-32 TOU S (21-100 kW); E-32 TOU M (101-400 kW); and E-32 TOU L (greater than 400 kW). The four new general service TOU rate schedules were designed with the same methodology and with the same objectives as previously described for E-32. (Delizio PTF, page 31). As shown above, customers react positively to TOU rates. Tailoring the rate offerings to better suit both size and cost to serve should result in even more positive behavior.

Third, Rate Schedules E-34 and E-35 are the rate schedules that are applicable to APS' largest customers. As described in the testimony of Company witness Delizio, the Basic Service Charge for both rate schedules has been increased to better reflect the Cost of Service, and language was added to the rate schedules to broaden the application of the demand charge discount for Military Base customers taking primary service and served from a dedicated distribution feeder. (Delizio PFT, page 32). The Company states that this change should result in both Luke Air Force Base and the Yuma Marine Corps Air Station being served on the same footing with regard to their electric service. Discounts for dedicated services help customers avoid paying for the carrying costs for all

distribution feeders on the system. This change is fair to both the Company and customers and should be accepted.

Fourth, given that these customers may at some point take direct access, the Company added a provision to the E-34 and E-35 rate schedules to require the 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. (Delizio PFT, page 33). This provision only applies in those instances where the arrangements can be directly attributable to a specific customer or customers. Passing direct costs on to those customers, who elect to take service from others, minimizes the risk of cross subsidization.

CANCELLING PARTIAL REQUIREMENTS RATE SCHEDULES

Q. Why is the Company proposing to cancel Partial Requirement Rate Schedules E32-R, E-51, and E-55?

A. The Company proposes that the existing Partial Requirement Rate Schedules, E-32R, E-51 and E-55, which are currently frozen, be cancelled. (Delizio PFT, page 30). This was an issue in the last APS rate case. In Decision No. 69663, the Commission adopted the Company's request to freeze Partial Requirement Rate Schedules E-32R, E-51, and E-55 and to cancel the rate schedules in this case. Company witness Delizio states that the services provided under these rate schedules are now covered by Schedules E-56 and SC-S. Mr. Delizio states that there are a total of four customers served under these rate schedules (two on E-32R, one on Schedule E-51, and one in Schedule E-55). The Company believes that these customers can migrate to Schedule E-56 and Schedule SC-S with minimal (if any) adverse impact on their bill.

Q. Do you agree with these Company-proposed changes?

A. Yes. As the number of customers is small, the current classes are frozen, and there are other rate schedules available to service them, the Company's proposal to consolidate the number of rate offerings is reasonable.

SOLAR POWER AND GREEN POWER MODIFICATIONS

Q. How does the Company propose to modify its Solar Power offerings?

A. The Company proposes to freeze the Solar-2 rate to customers currently served under its provisions. (Delizio PFT, page 34). Under Solar-2, the Company offers power generated by Company-owned and maintained solar electric systems for customers who cannot be economically connected by extension of the Company's distribution system. The systems typically will include a photovoltaic module array, the module array mounting structure, the control structure, the control equipment, any necessary wiring, batteries, and any other equipment necessary to provide service that meets all applicable building and safety codes at a mutually agreed upon point of delivery. The Company owns, maintains, and makes necessary repairs to the solar electric system. In his testimony, Company witness Delizio states the belief that Solar-2 is no longer necessary since customers may be eligible to participate in APS' Solar Partners Initiative Program and may be eligible for federal and state tax incentives not currently available to utilities. (Delizio PFT, page 34). There are currently only two customers served on Solar-2.

In an effort to encourage greater customer participation in solar power, the Company also proposes changes to Solar-3. Solar-3 is a pilot program, and service under the rate schedule provides all or a portion of the customer's service from solar electric generating systems producing AC electricity and delivered via APS' electric power grid. Customers pay the Company the cost of purchasing the solar power and are credited the avoided cost

value of the energy. In short, a premium is paid for taking solar power, but customers volunteer for the program in order to promote the technology. Currently, customers taking service under this rate schedule must have at least 50% or 100% of their energy supply provided from solar power. In addition, customers taking service under this rate schedule currently cannot combine it with other solar or green power options.

In this case, the Company is proposing two new subscription options: 10% and 35% with respect to the amount of the customer's power coming from solar power. These two new subscription options supplement the current 100% and 50% options. (Delizio PFT, page 34). The Company hopes that these additional choices will increase customer participation in solar power. (Delizio PFT, page 35). In addition, the Company has upgraded its billing system capability so that it can now offer customers the option to supplement energy usage by combining Solar-3 with either Green Power Service Schedule (GPS-1 or GPS-2). The Company states that this ability to "mix and match" will hopefully increase participation in all three rate schedules.

Q. Do you agree with these Company-proposed changes?

A. Yes. Staff supports the change to freeze Solar-2 because there are now many more options for customers to purchase solar power systems as opposed to buying them from the Company. Staff also supports the new subscription options for Solar-3. The added flexibility of lowering the purchase requirement levels and combining the solar program with other green power programs is commendable and should be supported.

DEMAND RESPONSE PROGRAMS

Q. Please comment on the Company's Demand Response Pricing Program Proposals.

A. Demand Response Programs are designed to provide incentives to customers to reduce their load. The need to reduce load may be the result of high prices, market conditions, or threats to system reliability. Demand Response can result in immediate savings of variable supply costs, and can displace the need to build additional transmission or generation capacity. Demand Response programs can be pricing programs, where the customer faces high prices during critical periods in exchange for lower prices during other time periods, or quantity programs, where the customer agrees to curtail load during critical periods. APS states that Time-of-Use rates and Critical Peak Pricing are two examples of Demand Response Programs. In Decision No. 69663, the Commission ordered the Company to conduct a study on demand response and to submit one or more programs based upon that study. (Decision No. 69663, page 154). The Commission also ordered the Company to consider a Critical Peak Pricing ("CPP") Program and offer it in its next rate filing. (Decision No. 69663, page 145).

Company Witness Miessner presents the Company's position on Demand Response Pricing Programs, which include Time-Of-Use Rates ("TOU"), Critical Peak Pricing ("CPP"), Real Time Pricing ("RTP"), and other concepts. Mr. Miessner also presents the research that the Company is conducting to formulate a Demand Response Strategy.

Based on this research, APS has concluded the following:

- Several Demand Response options, including TOU, CPP, and RTP, have resulted in moderate to high levels of load reduction during summer peak periods, depending on the particular utility's customer profile.

- TOU is available for more summer hours, compared to CPP, which may provide more consistent load reduction over time and have a greater impact on reducing capacity costs.
- TOU rates are likely to have a higher customer acceptance compared with CPP and RTP for residential customers and are typically less expensive to implement and operate compared with CPP and RTP.
- CPP programs are "dispatchable" and could provide load response during the most critical hours. However, CPP may appeal to a select group of customers that have the ability to reduce their usage on short notice.
- RTP programs are better targeted to commercial and industrial customers who can manage their usage to reduce the risks of being billed according to hourly energy prices.
- RTP programs are better suited for utilities with highly variable hourly energy prices and can have significant implementation costs, but are generally less effective in reducing peak load than either CPP or TOU. (Miessner PFT, page 7).

Based on these conclusions, APS is recommending a new residential TOU rate, which provides higher peak price signals during the highest summer peak hours. (Miessner PFT, page 8). The Company is also recommending that a CPP program be offered to General Service customers. The program will test the potential load reduction, customer acceptance, and implementation cost issues. The Company is not recommending a RTP program at this time because it does not believe that this option is likely to be as beneficial to APS and its customers compared to other Demand Response Pricing options.

Super Peak TOU Pricing

Q. Please summarize the proposed Residential TOU Rate with the Super Peak Price.

A. As explained by Company witness Miessner, the Company is proposing a new residential TOU rate with a Super Peak Price. The rate will be similar to rate ET-2, with a 7-hour on-peak period, but will add a Super Peak Price for weekday afternoons from 3:00 p.m. to 6:00 p.m. during June, July and August. The price for the Super Peak period is raised to $0.4895 per kWh from the normal price of $0.2349 per kWh. The summer off-peak price will be discounted more than the off-peak price for the ET-2 rate in order to off-set the higher Super Peak Price and to give customers the opportunity to lower monthly bills by reducing load during either the on-peak and/or Super-Peak Period. (Miessner PFT, page 9).

Q. Is the Company's proposal reasonable?

A. Yes, the Company's proposal to add a new Super Peak TOU option is yet another means by which to alleviate load during the critical peak period. As discussed before, the Company's existing TOU rate options have been effective in encouraging customers to move load to off-peak periods. The Super Peak TOU option, which concentrates the financial incentive in a select few hours during the peak months, could prove an even more effective tool. The off-peak price for the Super Peak rate is proposed to be $0.4671 per kWh as compared to the APS-proposed ET-2 off-peak rate of $0.05888 per kWh. Thus, for customers that can move load from the Super Peak period, the savings in the off-peak period would amount to a 20% savings which is significant and should act to incent customers to take action to shift load to the off-peak period. If successful, this type of program could be expanded to other TOU options in future rate cases.

Critical Peak Pricing

Q. Could you please summarize the Company's proposed Critical Peak Pricing ("CPP") Program?

A. To incent customers to reduce load during summer business hours, the Company is proposing a CPP program for General Service Customers, which the Company believes is the best group to target for CPP. The Company believes that this option should be limited at this time to 100 participants for a two-year trial period. The rate would be available to medium, large, and extra large General Service and Water Pumping customers served on rate schedules E-32 M, E-32 L, E-32TOU M, E-32TOU L, E-34, E-35 and E-221. Eligible customers must be capable of reducing usage during critical periods by a minimum of 200 kW and have interval metering.

Q. How would the customers be charged under the rate?

A. This rate schedule would provide a high price for critical hours, as determined by the Company, with one day advance notice. The customer would be charged an additional critical peak price of $0.40 per kWh for consumption during each hour of a "Critical Event", but would be compensated through a discount based on the customer's monthly kWh consumption. As shown on Attachment CAM-2 to Mr. Miessner's testimony, the discounts range from approximately $0.0128 per kWh to $0.149 per kWh, depending on the present rate schedule.

The CPP price and the discount are designed to be revenue neutral for each of the eligible rate classes described above. A customer would have the opportunity to reduce its bills if it reduces usage during the critical hours because the customer would avoid paying the critical peak price, but still receive the monthly discount.

Q. What is a "Critical Event" under APS' proposal?

A. A "Critical Event" may be invoked by the Company for the period from 2 p.m. to 7 p.m., weekdays during June through September, excluding designated holidays. Each "Critical Event" will last the entire 2 p.m. to 7 p.m. period. The critical hours would be limited to 90 hours per year, 5 hours per day, and 18 days per year. A "Critical Event" could be called for any weekday, June through September. The proposed tariff states that a 'Critical Event" could be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage as determined by the Company. Customers would be notified of a critical event in advance by 4:00 p.m. the day before by a phone message and/or e-mail.

Q. Why is the Company proposing restrictions on the program?

A. The Company believes that an initial restriction in participation is reasonable given that the program is new to APS and that there has been little or no experience with CPP programs implemented on a large scale basis. In addition there are uncertainties in program success because we do not know the amount of the typical bill savings and the persistence of the customer's load response over time. If successful, the program could be expanded and/or modified.

Q. Should the Company's proposed CPP program be adopted subject to certain modifications?

A. Yes. The Company's proposal to add a new CPP program is a positive step in helping to control peak load. It is targeted to customers that can most likely shed load; it provides an adequate discount to encourage participation (an approximate 22% savings in energy charges); and it is limited in scope so that it can be controlled, evaluated, and improved

before it is offered to all customers. However, Staff does believe there are two improvements to this offering that should be implemented.

First, since this is a pilot program, it should be structured so that one can learn as much as possible from it. As proposed, the definition of a "Critical Event" is very open ended, and it is possible that no "Critical Events" would occur while the program is in place. As such, the Company, Commission and customers would learn nothing. To successfully test how customers react to the need for a demand response, one must have actual data. As such, Staff would change the tariff language to state that the Company will invoke a minimum of 6 CPP Events and a maximum of 18 CPP Events per calendar year.

Second, as the Company is proposing to offer CPP to seven different service classes, Staff is concerned that limiting the number of participants to 100 may result in sample sizes that are too small to evaluate. Staff recommends that the number of participants be increased to 200.

Q. Have you prepared tables showing Staff's proposed rate design and typical bills.

A. Staff will file schedules containing comparisons of present and proposed rates and typical bills by January 16, 2009.

<u>OTHER RATE MODIFICATIONS</u>

Q. Please describe the Company's proposed changes to the current Environmental Improvement Surcharge.

A. APS states that the Commission has a real commitment to protecting Arizona's environment, and through its past decisions, the Commission has demonstrated that environmental protection is a compelling public interest. And the Company further states

that the use of surcharges is appropriate in order to establish programs that support environmental protection. APS goes on to state that the Environmental Improvement Surcharge ("EIS") currently collects only $4.3 million per year (roughly $2.6 million after tax), and the funds are accounted for as Contributions in Aid of Construction ("CIAC"). APS notes that the projected capital environmental improvement costs for the Cholla Generating Station alone are more than $332 million through 2012. Thus, APS argues that the current EIS does not recover any significant portion of these costs.

APS believes that it is appropriate to expand and expedite the recovery of such environmental costs. APS recommends that the Commission modify the EIS by allowing for a return on investment and a recovery of expenses rather than treating the amounts collected through the EIS surcharge as CIAC. APS indicates that this modification will reduce the up-front dollar rate impact on customers of such environmental improvements.

The Company proposes to implement an adjustor mechanism that would allow the Company to modify the EIS charge on an annual basis as needed to recover actual costs of environmental improvement projects. APS estimates that, if the EIS were to be updated at this time, it would be $0.000179/kWh or only slightly above the current value of $0.00016/kWh. APS does not propose a change to the current EIS and would recover these additional EIS costs in the 2010 EIS filing.

Q. Should the Company's proposed changes to the current EIS be adopted?

A Not as proposed by APS. The Company's position in this case has not changed from its position in the Company's last general rate case. At that time, both RUCO and Staff objected to the implementation of a similar APS proposal for a myriad of reasons. In Decision No. 69663, the Commission stated that APS should be proactive, rather than

reactive, on issues of environmental improvement. The Commission expressly recognized APS' arguments that the cost of mandated improvements may increase once those improvements become mandatory, and that implementing the improvements earlier may be less costly and also bring environmental benefits sooner. The Commission found, however, that the method by which APS proposed to seek recovery of those costs was unusual and outside of the normal ratemaking process. Ultimately, the Commission adopted an EIS surcharge set at $.00016 per kWh and further directed that the level of the EIS shall remain in effect until further order by the Commission.

The arguments made by APS in this case are essentially the same as those made in the last case. APS cites the magnitude of the dollars at issue as a reason for changing the EIS surcharge, to an automatic adjustor mechanism. The dollar value of the environmental improvements to the Cholla plant presented by the Company in this case is $332 million. This compares to an amount cited by APS in the prior case of $243 million. But the magnitude of dollars involved is hardly reason enough to justify such a significant departure from the normal ratemaking process. The use of an automatic adjustor mechanism bypasses the normal checks and balances that are part of the regulatory process in a utility base rate case. The trend of ever-expanding automatic adjustment mechanisms has been of concern to the Commission. Moreover, of particular concern to the Commission in APS' last rate case, was the fact that the adjustor mechanism would include forecasted costs as well. No new arguments have been made by APS in the current case and a compelling need for dramatically changing the nature of the EIS, as proposed by APS, has not been demonstrated. Consequently, Staff recommends that APS' proposed modifications to the EIS Surcharge be rejected.

TRANSMISSION COST ADJUSTMENT

Q. Please describe the Company's proposal with respect to the Transmission Cost Adjustment ("TCA").

A. As explained by Company witness Rumolo, the Company proposes that the Federal Energy Regulatory Commission ("FERC") regulated charges be removed from base rates and directly charged to customers through a separate transmission rate schedule, TCA-1. (Rumolo PFT, page 23).

Q. Does APS currently have a TCA?

A. Yes. The current TCA was established as part of a settlement in Docket No. E-01345A-03-0437. Per the terms of the settlement in that case, the TCA was established in order to ensure that any potential direct access customers will pay the same for transmission as standard offer customers. The TCA was limited to recovery of costs associated with changes in the Company's open access transmission tariff ("OATT") or equivalent tariff. The TCA does not take effect until the transmission component of retail rates exceeds the base of $0.000476 per kWh by five percent. When this trigger amount is reached, the Company may file for Commission approval of a TCA rate. Decision No. 69663 required the Company to restructure its retail rates so that the transmission component of the rates reflected the then current OATT charges.

Q. How does the Company propose to change the TCA?

A. The Company's proposals with respect to the TCA and TCA-1 would directly incorporate by reference the Company's then-effective transmission rates, and the TCA would reflect the transmission cost found in base rates today, plus any increased charges in the future. (Rumolo PFT, page 23). When the FERC-regulated transmission rates are changed, APS would re-file the retail transmission rate schedule TCA-1 with the new charges.

Q. Do you agree with the proposed change?

A. No. The proposal to modify the TCA is unnecessary. The current TCA provides the Company the ability to recover its costs. The Company merely needs to file for a change and request Commission approval. The mechanism proposed by the Company would allow the Company to pass through increases to customers without the need for Commission approval. Continued Commission oversight is important. The Commission may elect to not raise rates and simply defer the charge for later recovery. The Commission may want to defer the change for a variety of reasons. Further, automatic adjustment clauses are generally disliked by customers. Automatic adjustment clauses eliminate risk to the utility and reduce the Company's incentive to control costs. Thus, they should only be established with good cause, and no demonstration of that has been made here. The current TCA achieves the correct balance between the needs of the Company and those of the customer, and should not be modified as requested by the Company.

OTHER TARIFF MODIFICATIONS

Q. Are there other rate modifications being proposed by the Company?

A. Yes. The Company has modified EPR-2 purchase rates to reflect updated avoided cost numbers. The purchase rates have been further refined by defined on-peak/off-peak periods, season, and level of firmness. The on-peak/off-peak purchase price has been segregated by TOU periods of 9 a.m.-9 p.m., noon-7 p.m., and 11 a.m.-9 p.m. on weekdays.

The Company also seeks to modify Service Schedules 1, 4, 5, 8, 10 and 15 in a number of respects. These changes clarify existing provisions of the Schedules or make changes to reflect today's business environment. For example, APS is proposing additional language

to Section 2.7.6 of Schedule 1 to provide for a security deposit not to exceed "the higher amount of either: one (1) times the customer's maximum monthly bill; or two (2) times the customer's average monthly bill as estimated by Company for the services being provided by Company." This replaces language that limited the deposit to two times the average monthly bill. APS acknowledges that it seeks a variance from a Commission rule enacted many years ago, but argues the rule likely reflected a time when peak monthly bills were closer to the average monthly bill than is presently the case.

Q. Do you agree with those APS-proposed changes?

A. Yes. This seems reasonable to change the rules to reflect conditions that exist today.

Demand Side Management Recovery Mechanism

Q. What is Staff's position concerning Demand Side Management recovery mechanisms?

A. In my direct testimony Staff commented on the reasonableness of the Company's proposed changes to the Demand Side Management ("DSM") adjustor mechanism. In addition, Staff witness Ralph Smith testified that the impacts of Staff's recommendations on the recovery mechanism for DSM related costs are not yet known and would be addressed in Staff's rate design testimony filing (Smith PFT, page 11). In Staff witness Smith's accompanying supplemental testimony, he discusses an APS operating income adjustment related to Demand Side Management and estimated future net revenue losses that APS attributes to DSM. My testimony relates to the policy aspects of the DSM recovery mechanisms and describes how APS is compensated for performing DSM through a performance incentive mechanism that is designed to reward APS only when its DSM programs are successful and result in energy or demand savings.

Staff strongly supports steps to encourage energy conservation and that goes to DSM programs as well. That said, however, the DSM lost revenue cost recovery mechanism covers a wide spectrum of possibilities. At one extreme is complete, or full, revenue decoupling mechanism where the utility is protected from any variations from projected revenue forecasts between rate cases regardless of the reason. At the other end of the spectrum is where a utility is ordered to implement energy conservation measures to avoid building, or buying, generation resources and no compensation is given. APS' current DSM programs include a performance incentive mechanism that rewards the Company only when its DSM programs are successful and result in energy or demand savings. Thus, APS' current program strikes the right balance. Additionally, Decision No. 67744 in a previous APS case adopted a Settlement Agreement that provided for a DSM performance incentive. As noted by the Commission in Decision No. 69663, under that Settlement Agreement, APS was not allowed to recover net lost revenues.

In this case, with its DSM income adjustment, the Company is attempting to recover estimated future net lost revenues that APS attributes to DSM. One must remember that every time rates are re-set, the Company is made whole for their so called lost revenues. As Staff noted in my initial testimony the current DSM adjustor mechanism gives APS 10% of program expenditures each year. Recovery of estimated future lost revenues and a performance incentive mechanism are two different and mutually exclusive means to compensate the utility for performing DSM. The Company has agreed to a performance incentive as part of a settlement that balanced the interests of all parties. Thus, the utility

is already compensated for performing DSM. Accordingly, APS' request for recovery of estimated future net lost revenues attributed to DSM should be rejected.

Q. Does this conclude your rate design testimony?

A. Yes, it does, except that Staff will file schedules containing comparisons of present and proposed rates and typical bills by January 16, 2009.

Exhibit__(FWR-2)

APS Response to Staff Discovery Request 22.7

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
NOVEMBER 14, 2008

Staff 22.7 RE: Delizio Testimony pages 15-16, are there any specific workpapers that tie the results of the cost of service study to the revenue allocation? If so, please provide them. If not, for each service class and each rate schedule (e.g. E-32, 21-100 kW) please provide an explanation of how the results of the cost of service study are used in your recommended revenue allocation.

Response: Yes. The attached table provides a comparison between cost of service revenue deficiency for each rate class and the proposed revenue increase. The cost of service provides a guide for revenue allocation – lower performing rates in terms of revenue deficiency or rate of return received a relatively higher proposed increase and visa versa. However, the proposed increases are not designed to return each rate class to cost parity, but rather to move in that direction. Other objectives considered in the revenue allocation process include, for example, (1) preserving rate stability and avoiding rate shock for any rate class, (2) reducing, but not eliminating, the return differential between general service and residential revenue classes, and (3) preserving consistency between time-of-use rates and other rate options. The attachment is provided in Excel format as APS13779.

Witness: Gregory DeLizio

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2007 ADJUSTED

Customer Classification and Current Rate Designation	Average Number of Customers	Adjusted MWh Sales	Base Revenues under Present Rates[1] ($000)	Proposed Rate Designation	Proposed Base Revenues ($000)	Proposed Transmission Revenues ($000)	Proposed Total Revenues ($000)	Increase -Base Rates Amount ($000) (I) - (E)	Increase -Base Rates % (J) / (E)	PSA Impacts[5] ($000)	Bill Impacts Net of PSA Impacts[5] ($000)	Bill Impacts Net of PSA Impacts[5] %	COSS Revenue Requirement Deficiency
Residential													
E-10	62,712	526,327	57,215	E-12	63,903	2,717	66,620	9,405	16.44%	(3,100)	6,305	11.02%	42.8%
E-12	447,532	4,053,590	442,588	E-12	494,535	20,785	515,320	72,732	16.43%	(23,880)	48,852	11.04%	9.3%
EC-1	17,348	343,675	32,443	ECT-1R	36,400	1,751	38,151	5,708	17.59%	(2,024)	3,684	11.36%	50.1%
ET-1	353,442	6,181,124	594,946	ET-1	667,843	31,529	699,372	104,426	17.55%	(36,411)	68,015	11.43%	12.9%
ECT-1R	48,110	1,418,894	122,822	ECT-1R	138,661	7,251	145,912	23,090	18.80%	(8,358)	14,732	11.99%	38.5%
ET-2	29,822	724,545	70,808	ET-2	79,523	3,712	83,235	12,427	17.55%	(4,268)	8,159	11.52%	22.9%
ECT-2	7,046	308,660	26,213	ECT-2	29,488	1,587	31,075	4,862	18.55%	(1,818)	3,044	11.61%	38.5%
Total Residential	966,012	13,556,815	1,347,035		1,510,353	69,332	1,579,685	232,650	17.27%	(79,859)	152,791	11.34%	21.7%
General Service													
E-20	329	34,392	3,267	E-20	3,631	296	3,927	660	20.20%	(203)	457	13.99%	34.3%
E-21	20	1,037	123	E-32TOU	139	6	145	22	17.89%	(6)	16	13.01%	7.8%
E-22	13	2,622	308	E-32TOU	350	18	368	60	19.48%	(15)	45	14.61%	7.8%
E-23	84	19,246	1,749	E-32TOU	1,977	76	2,053	304	17.38%	(113)	191	10.92%	7.8%
E-24	38	111,865	7,722	E-32TOU	8,699	317	9,016	1,294	16.76%	(659)	635	8.22%	7.8%
E-30	4,618	5,548	1,134	E-30	1,334	12	1,346	212	18.69%	(33)	179	15.78%	21.5%
E-32 (0 to 20 KW)	89,228	1,435,595	172,703	E-32 (0 to 20 KW)	198,866	6,087	204,953	32,250	18.67%	(8,457)	23,793	13.78%	21.5%
E-32 (21 to 100 KW)	18,248	2,727,984	272,756	E-32 (21 to 100 KW)	303,734	14,223	317,957	45,201	16.57%	(16,070)	29,131	10.68%	10.3%
E-32 (101 to 400 KW)	4,058	3,468,621	292,377	E-32 (101 to 400 KW)	325,073	14,730	339,803	47,426	16.22%	(20,433)	26,993	9.23%	8.9%
E-32 (401+ kw)	1,006	4,067,019	306,941	E-32 (401+ kw)	340,594	14,666	355,260	48,319	15.74%	(23,958)	24,361	7.94%	3.9%
E-32TOU	64	76,981	5,526	E-32TOU	6,349	75	6,424	898	16.24%	(453)	445	8.05%	7.9%
E-34	39	1,282,858	84,806	E-34	94,544	4,280	98,824	14,018	16.53%	(7,557)	6,461	7.62%	13.2%
E-35	20	1,554,899	89,217	E-35	101,039	4,857	105,896	16,679	18.69%	(9,160)	7,519	8.43%	20.3%
E-40	1	1	1	E-40	2	-	2	1	18.42%	-	1	11.60%	21.5%
E-51	1	8,748	602	E-56	698	29	727	125	20.76%	(52)	73	12.13%	18.8%
E-55	1	8,170	936	E-56	1,035	32	1,067	131	14.00%	(48)	83	8.87%	13.2%
Total General Service	117,768	14,805,686	1,240,168		1,388,064	59,704	1,447,768	207,600	16.74%	(87,217)	120,383	9.71%	11.6%
Irrigation and Water Pumping													
E-38, E-38-8T, E-38TOW	71	5,658	430	E-221, E-221-8T, E-221TOW	443	26	469	39	9.07%	(33)	6	1.40%	1.8%
E-221, E-221-8T, E-221TOW	1,397	332,112	24,946	E-221, E-221-8T, E-221TOW	25,918	2,110	28,028	3,082	12.35%	(1,956)	1,126	4.51%	3.8%
Total Irrigation	1,468	337,770	25,376		26,361	2,136	28,497	3,121	12.30%	(1,989)	1,132	4.46%	3.8%
Outdoor Lighting													
E-58	600	31,868	8,719	E-58	10,271	135	10,406	1,687	19.35%	(188)	1,499	17.19%	34.3%
E-59, City Streetlight Contracts	243	82,185	7,635	E-59, City Streetlight Contrac	8,773	348	9,121	1,486	19.46%	(484)	1,002	13.12%	34.3%
E-67	189	3,944	178	E-67	198	17	215	37	20.79%	(23)	14	7.87%	34.3%
Contract	40	10,753	840	Contract	957	45	1,002	162	19.29%	(63)	99	11.79%	34.3%
Total Outdoor Lighting	1,072	128,750	17,372		20,199	545	20,744	3,372	19.41%	(758)	2,614	15.05%	34.3%
Dusk to Dawn Lighting Service		26,102	7,496		8,836	111	8,947	1,451	19.36%	(154)	1,297	17.30%	14.2%
Total Sales to Ultimate Retail Customers	1,086,320	28,855,123	2,637,447		2,953,813	131,828	3,085,641	448,194	16.99%	(169,977)	278,217	10.55%	15.9%

EXHIBIT (FWR-3)

TABLE SHOWING STAFF AND COMPANY PROPOSED REVENUE ALLOCATION

Exibit__(FWR-3)

Arizona Public Service
Docket No. E-01345A-08-0172

Staff and Company Proposed Revenue Allocation

Customer Classification and Current Rate Designation	Proposed Rate Designation		Company Proposal: Adjusted Present Revenue ($)	Adjusted Proposed Revenue ($)	Transmission Revenue ($)	Total Proposed Revenue ($)	Increase ($)	Percent Increase	Staff Proposal: Total Present Revenues net of E-3 & E-4	Staff Prposed Increase	E-3, E-4 Revenues	Staff Total Proposed Revenue	Increase	Percent Increase
Residential														
E10	E-12		57,214,435	63,903,558	2,716,910	66,620,468	9,406,033	16.44%	53,743,948	6,352,777	3,470,487	63,567,212	6,352,777	11.10%
E12	E-12		442,587,367	494,535,672	20,785,346	515,321,018	72,733,651	16.43%	422,287,335	49,916,268	20,300,032	492,503,635	49,916,268	11.26%
EC-1	ECT-1R		32,442,990	36,399,749	1,751,482	38,151,232	5,708,242	17.59%	32,070,829	3,790,917	372,161	36,233,907	3,790,917	11.68%
ET-1	ET-1		594,945,870	667,842,652	31,528,547	699,371,199	104,425,329	17.55%	578,443,018	68,374,575	16,502,852	663,320,445	68,374,575	11.49%
ECT-1R	ECT-1R		122,821,690	138,660,904	7,250,921	145,911,825	23,090,135	18.80%	121,832,838	14,401,191	988,852	137,222,881	14,401,191	11.73%
ET-2	ET-2		70,807,787	79,523,220	3,711,971	83,235,190	12,427,403	17.55%	68,963,250	8,151,767	1,844,537	78,959,554	8,151,767	11.51%
ECT-2	ECT-2		26,212,827	29,487,893	1,587,272	31,074,965	4,862,138	18.55%	25,835,838	3,065,733	276,989	29,278,580	3,065,733	11.70%
		Total Residential	1,347,032,966	1,510,353,447	68,332,449	1,578,685,896	232,652,930	17.27%	1,303,277,056	154,053,228	43,755,910	1,501,086,194	154,053,228	11.44%
General Service														
E-20	E-20		3,267,158	3,630,840	296,217	3,927,057	659,899	20.20%	3,267,158	386,193		3,653,351	386,193	11.82%
E-30	E-30		1,133,744	1,333,845	12,098	1,345,743	211,999	18.70%	1,133,744	134,014		1,267,758	134,014	11.82%
E-34	E-34		84,805,810	94,544,275	4,279,809	98,824,084	14,018,274	16.53%	84,805,810	10,024,429		94,830,239	10,024,429	11.82%
E-35	E-35		89,217,103	101,038,587	4,856,952	105,895,539	16,678,436	18.69%	89,217,103	10,545,864		99,762,967	10,545,864	11.82%
E-40	E-40		1,305	1,542	6	1,548	243	18.62%	1,305	154		1,459	154	11.82%
E-51	E-56		602,059	698,861	28,286	727,147	125,088	20.78%	602,059	71,166		673,225	71,166	11.82%
E-55	E-56		936,310	1,035,064	32,376	1,067,440	131,130	14.01%	936,310	110,676		1,046,986	110,676	11.82%
New E-32 Rates														
E-21	E-32TOU		123,129	139,215	6,477	145,692	22,563	18.32%	123,129	14,554		137,683	13,535	
E-22	E-32TOU		308,204	349,675	18,464	368,139	59,935	19.45%	308,204	36,431		344,635	24,487	
E-23	E-32TOU		1,749,448	1,976,532	75,918	2,052,450	303,002	17.32%	1,749,448	206,793		1,956,241	180,140	
E-24	E-32TOU		7,721,782	8,698,642	316,872	9,015,514	1,293,732	16.75%	7,721,782	912,749		8,634,531	805,678	
E-32 (0 to 20 KW)	E-32 (0 to 20 KW)		172,702,526	198,868,184	6,086,630	204,952,814	32,250,288	18.67%	172,702,526	20,414,218		193,116,744	24,911,744	
E-32 (21 to 100 KW)	E-32 (21 to 100 KW)		272,755,575	303,734,186	14,222,605	317,956,791	45,201,216	16.57%	272,755,575	32,240,940		304,996,515	31,721,087	
E-32 (101 to 400 KW)	E-32 (101 to 400 KW)		292,377,288	325,073,305	14,729,680	339,802,985	47,425,697	16.22%	292,377,288	34,560,315		326,937,603	33,231,801	
E-32 (401-999 kw)	E-32 (401-999 kw)		306,941,087	340,594,113	14,666,186	355,260,299	48,319,212	15.74%	306,941,087	36,281,821		343,222,908	33,669,255	
E-32 TOU	E-32 TOU		5,526,429	6,348,751	74,684	6,423,435	897,006	16.23%	5,526,429	653,249		6,179,678	743,343	
		Subtotal E-32 Rates	1,060,205,468	1,185,780,602	50,197,517	1,235,978,119	175,772,651	16.58%	1,060,205,468	125,321,070		1,185,526,538	125,321,070	11.82%
		Total General Service	1,240,168,957	1,388,063,417	59,703,261	1,447,766,678	207,597,720	16.74%	1,240,168,957	146,593,566		1,386,762,524	146,593,566	11.82%
Irrigation and Water Pumping														
E-38	E-221, E-221-8T, E-221TOW		430,321	443,099	26,112	469,212	38,891	9.04%	430,321	50,866		481,187	50,866	11.82%
E-221	E-221, E-221-8T, E-221TOW		24,945,866	25,918,207	2,109,656	28,027,863	3,081,998	12.35%	24,945,866	2,948,714		27,894,579	2,948,714	11.82%
		Total Irrigation	25,376,187	26,361,306	2,135,769	28,497,075	3,120,889	12.30%	25,376,187	2,999,580		28,375,766	2,999,580	11.82%
Outdoor Lighting														
E-58	E-58		8,719,188	10,271,074	135,275	10,406,350	1,687,162	19.35%	8,719,188	1,030,647		9,749,835	1,030,647	11.82%
E-59	E-59		7,635,291	8,772,681	348,078	9,120,759	1,485,468	19.46%	7,635,291	902,526		8,537,817	902,526	11.82%
E-67	E-67		178,381	198,109	16,846	214,756	36,375	20.39%	178,381	21,085		199,466	21,085	11.82%
Contract 12	Contract 12		840,117	957,363	45,401	1,002,764	162,647	19.36%	840,117	99,306		939,423	99,306	11.82%
		Total Outdoor Lighting	17,372,977	20,199,228	545,401	20,744,629	3,371,651	19.41%	17,372,977	2,053,564		19,426,542	2,053,564	11.82%
Dusk to Dawn														
E-47			7,496,002	8,835,659	110,813	8,946,472	1,450,470	19.35%	7,496,002	886,061		8,382,063	886,061	11.82%
		Total Dusk to Dawn	7,496,002	8,835,659	110,813	8,946,472	1,450,470		7,496,002	886,061		8,382,063	886,061	11.82%
		Grand Total	2,637,447,089	2,953,813,057	131,827,892	3,085,640,750	448,193,660	16.99%	2,593,691,179	306,586,000		2,944,033,089	306,586,000	11.62%

EXHIBIT
S-9
ADMITTED
ALL-STATE LEGAL®

BEFORE THE ARIZONA CORPORATION COMMISSI

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 SUPPLEMENTAL DIRECT TESTIMONY ON RATE DESIGN AND EXHIBIT FWR-4**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Supplemental Direct Testimony on Rate Design of Staff Witness Frank W. Radigan and Exhibit FWR-4 in the above-referenced matter.

RESPECTFULLY SUBMITTED this 16th day of January, 2009.

Janet Wagner, Assistant Chief Counsel
Maureen A. Scott, Staff Senior Counsel
Charles Hains, Attorney
Amanda Ho, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing filed this 16th day of January, 2009 with:

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

. . .

Copies of the foregoing mailed this
16th day of January, 2009 to:

Thomas L. Mumaw
Meghan H. Grabel
PINNACLE WEST CAPITAL CORPORATION
LAW DEPARTMENT
P.O. Box 53999
Phoenix, Arizona 85072-3999

William J. Maledon
OSBORN MALEDON P.A.
2929 North Central Avenue
Phoenix, Arizona 85067-6379

Robert Metli
SNELL & WILMER L.L.P.
400 East Van Buren Street
Phoenix, Arizona 85004-2202

Barbara Klemstine
Zachary Fryer
Susan Casady
ARIZONA PUBLIC SERVICE COMPANY
P.O. Box 53999
Mail Station 9708
Phoenix, Arizona 85072-3999

Michael L. Kurtz
Kurt J. Boehm
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG P.C.
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012-2913

Lawrence V. Robertson, Jr.
Attorney at Law
P.O. Box 1448
Tubac, Arizona 85646

Michael A. Curtis
William P. Sullivan
CURTIS, GOODWIN, SULLIVAN,
UDALL & SCHWAB, P.L.C.
501 East Thomas Road
Phoenix, Arizona 85012-3205

. . .

. . .

Timothy M. Hogan
ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004

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

Michael M. Grant
GALLAGHER & KENNEDY
2575 East Camelback Road
Phoenix, Arizona 85016-9225

Gary Yaquinto
ARIZONA INVESTMENT COUNCIL
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004

Jay I. Moyes
Karen E. Nally
MOYES SELLERS & SIMS
1850 North Central Avenue, Suite 1100
Phoenix, Arizona 85004-0001

David Berry
WESTERN RESOURCE ADVOCATES
P.O. Box 1064
Scottsdale, Arizona 85252

Jeff Schlegel
SWEEP Arizona Representative
1167 West Samalayuca Drive
Tucson, Arizona 85704

Jeffrey J. Woner
K.R. SALINE & ASSOC., PLC
160 North Pasadena, Suite 101
Mesa, Arizona 85201

Scott Canty, General Counsel
THE HOPI TRIBE
P.O. Box 123
Kykotsmovi, Arizona 86039

Karen S. White
Air Force Utility Litigation &
Negotiation Team
AFLO/JACL-UTL
139 Barnes Drive
Tyndall AFB, Florida 32403

. . .

John Moore, Jr.
7321 North 16th Street
Phoenix, Arizona 85020

Cynthia Zwick
1940 East Luke Avenue
Phoenix, Arizona 85016

Karyn Christene

SUPPLEMENTAL

DIRECT

TESTIMONY

OF

FRANK W. RADIGAN

DOCKET NO. E-01345A-08-0172

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 RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN

JANUARY 16, 2009

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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 RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01345A-08-0172

SUPPLEMENTAL DIRECT TESTIMONY

ON THE ISSUES OF REVENUE ALLOCATION

AND RATE DESIGN

OF

FRANK W. RADIGAN

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JANUARY 16, 2009

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. DESCRIPTION OF EXHIBIT 1

SCHEDULES

Schedules H-3 and H-4 Using Staff's Proposed Rate Design .....Exhibit FWR-4

SUPPLEMENTAL EXECUTIVE SUMMARY
ARIZONA PUBLIC SERBVICE COMPANY
DOCKET NO. E-01345A-08-0172

The purpose of my testimony is to present Staff's Schedules H-3 and H-4 which are put forth as one exhibit, Exhibit FWR-4. Schedule H-3 shows present and proposed rates by rate schedule. Schedule H-4 shows a comparison of typical bills under present and proposed rates by various consumption levels for each rate schedule.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Frank W. Radigan. I am a principal in the Hudson River Energy Company, a consulting firm providing services to the utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. Are you the same Frank Radigan who previously filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your supplemental testimony you are presenting?

A. The purpose of my testimony is to present Staff's Schedules H-3 and H-4 which are put forth as one exhibit, Exhibit FWR-4. Schedule H-3 shows present and proposed rates by rate schedule. Schedule H-4 shows a comparison of typical bills under present and proposed rates by various consumption levels for each rate schedule.

II. DESCRIPTION OF EXHIBIT

Q. Please describe what information is presented in Exhibit FWR-4.

A. The schedules present the rates and bill comparisons that reflect Staff's proposed revenue requirement, revenue allocation and rate design. Schedule H-3 is a 25 page document that shows the detailed rates by component for each of the Company's current and proposed rate schedules. Schedule H-4 contains 63 pages and presents comparison of monthly bills not only for each rate schedule but also by season. This schedule is presented in the same format as the Company's Schedule H-4 and is helpful in assessing how the proposed revenue allocation and rate design will impact a customer's electric bill.

Q. Could you please describe the impact of your proposed rate design for a few of the largest service classifications?

A. Yes. The rate schedule with the largest number of customers is E-12 – Residential Service Standard Rate and the typical bill comparison for the summer period, May-October, is shown on Schedule H-4, page 2 of 63 of Exhibit FWR-4. A customer on rate schedule E-12 using 600 kWh per month (very close to the median usage of 617 kWh) will see an increase of 11.5%. This is slightly higher than the class average increase of 11.3%. The reason for the slightly higher increase is due to the higher than average increase being given to the basic service charge.

Q. What is the impact on low-income customers?

A. Under Staff's proposed rate design, low-income customers receive no increase. The Support Programs are rate schedules E-3 Energy Support Program and E-4 Medical Equipment Support Program. The Support Programs are offered under each of the residential service rate schedules, and none of them are getting a rate increase under Staff's proposed rate design. For example, the typical bill comparison of a E-3 customer taking service under ET-1 – Residential Service TOU Energy Advantage Rate is shown on Schedule H-4, page 10 of 63 of Exhibit FWR-4 and as can be seen there is no increase in the bill for this customer under Staff's rate design.

Q. Can you give an example of the rate impact to a general service customer?

A. Yes, the E-32 Small General Service (21-100 kW) is one of the largest general service rate schedules. As shown on Schedule H-4, page 38 of 63 of Exhibit FWR-4 a customer with a 60 kW demand and a load factor of 45% during the summer period will receive an increase of 11.7% or very close to the overall average increase of 11.8%.

Q. What is the expected rate increase for the Company's largest customers served under E-35 Extra Large General Service Time of Use Rate?

A. As shown on Schedule H-4, page 52 of 63 of Exhibit FWR-4 a customer with a 4,500 kW on-peak demand and a load factor of 40% will receive an increase of 11.8% which is equal to the overall average increase of 11.8%. In fact, all usages shown for this rate schedule receive the average increase which is reflective of Staff's rate design that increased all charges (other than the low-income support rates E-3 and E-4) on an equal percentage basis.

Q. Does this conclude your supplemental direct testimony?

A. Yes, it does.

Exhibt (FWR-4)

Schedules H-3 (25 pages) and H-4 (63 pages)
Using
Staff's Proposed Revenue Increase, Revenue Allocation and Rate Design

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
1	E-3	Residential Energy	Rate	Sum & Win	For Bills 0-400 kWh	40%	disc.	NO CHANGE					1
2		Support Program			For Bills 401-800 kWh	26%	disc.						2
3					For Bills 801-1200 kWh	14%	disc.						3
4					For Bills 1201 kWh and above	$ 13.00	disc.						4
5													5
6	E-4	Medical Care	Rate	Sum & Win	For Bills 0-800 kWh	40%	disc.	NO CHANGE					6
7		Equipment			For Bills 801-1400 kWh	26%	disc.						7
8		Support Program			For Bills 1401-2000 kWh	14%	disc.						8
9					For Bills 2001 kWh and above	$ 26.00	disc.						9
10													10
11	E-10	Residential Service	Rate	Summer	RATE E-10 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE E-12.			RATE E-10 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE E-12.					11
12	(INTERIM)												12
13													13
14													14
15													15
16				Winter									16
17													17
18													18
19			Minimum	Sum & Win									19
20													20
21	E-12	Residential Service	Rate	Summer	Basic Service Charge	$ 0.253	/day	Basic Service Charge	$ 0.312	/day	$ 0.05880	/day	21
22					First 400 kWh	0.08570	/kWh	0-400 kWh	0.09429	/kWh	0.00859	/kWh	22
23					Next 400 kWh	0.12175	/kWh	401-800 kWh	0.13395	/kWh	0.01220	/kWh	23
24					All additional kWh	0.14427	/kWh	801-3000 kWh	0.15873	/kWh	0.01446	/kWh	24
25								3001 kWh and above	0.16987	/kWh	0.02560	/kWh	25
26													26
27				Winter	Basic Service Charge	$ 0.253	/day	Basic Service Charge	$ 0.312	/day	$ 0.05880	/day	27
28					All kWh	0.08327	/kWh	All kWh	0.09162	/kWh	0.00835	/kWh	28
29													29
30			Minimum	Sum & Win	Basic Service Charge	$ 0.253	/day	Basic Service Charge	$ 0.312	/day	$ 0.05880	/day	30
31													31
32	EC-1	Residential Service	Rate	Summer	RATE EC-1 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE ECT-1R.			RATE EC-1 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE ECT-1R.					32
33	(INTERIM)	With Demand Charge											33
34													34
35													35
36				Winter									36
37													37
38													38
39													39
40			Minimum	Sum & Win									40

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
41													41
42	ET-1	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	42
43		Time of Use			All On-Peak kWh	0.15810	/kWh	All On-Peak kWh	0.17811	/kWh	0.02001	/kWh	43
44					All Off-Peak kWh	0.05110	/kWh	All Off-Peak kWh	0.05757	/kWh	0.00647	/kWh	44
45													45
46				Winter	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	46
47					All On-Peak kWh	0.12845	/kWh	All On-Peak kWh	0.14471	/kWh	0.01626	/kWh	47
48					All Off-Peak kWh	0.04925	/kWh	All Off-Peak kWh	0.05548	/kWh	0.00623	/kWh	48
49													49
50			Minimum	Sum & Win	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	50
51													51
52	ET-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	52
53		Time of Use			All On-Peak kWh	0.21601	/kWh	All On-Peak kWh	0.24379	/kWh	0.02778	/kWh	53
54					All Off-Peak kWh	0.05413	/kWh	All Off-Peak kWh	0.06108	/kWh	0.00696	/kWh	54
55													55
56				Winter	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	56
57					All On-Peak kWh	0.17519	/kWh	All On-Peak kWh	0.19772	/kWh	0.02253	/kWh	57
58					All Off-Peak kWh	0.05412	/kWh	All Off-Peak kWh	0.06108	/kWh	0.00696	/kWh	58
59													59
60			Minimum	Sum & Win	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	60
61													61
62	ECT-1R	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	62
63		Time of Use with			All On-Peak kW	11.86	/kW	All On-Peak kW	13.342	/kW	1.48178	/kW	63
64		Demand Charge			All On-Peak kWh	0.06593	/kWh	All On-Peak kWh	0.07417	/kWh	0.00824	/kWh	64
65					All Off-Peak kWh	0.03689	/kWh	All Off-Peak kWh	0.04150	/kWh	0.00461	/kWh	65
66													66
67				Winter	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	67
68					All On-Peak kW	8.15	/kW	All On-Peak kW	9.166	/kW	1.01626	/kW	68
69					All On-Peak kWh	0.04875	/kWh	All On-Peak kWh	0.05587	/kWh	0.00622	/kWh	69
70					All Off-Peak kWh	0.03526	/kWh	All Off-Peak kWh	0.03967	/kWh	0.00441	/kWh	70
71													71
72			Minimum	Sum & Win	Minimum	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	72
73													73
74	ECT-2	Residential Service	Rate	Summer	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	74
75		Time of Use with			All On-Peak kW	11.87	/kW	All On-Peak kW	13.384	/kW	1.49443	/kW	75
76		Demand Charge			All On-Peak kWh	0.07633	/kWh	All On-Peak kWh	0.08519	/kWh	0.00886	/kWh	76
77					All Off-Peak kWh	0.03864	/kWh	All Off-Peak kWh	0.04350	/kWh	0.00486	/kWh	77
78													78
79				Winter	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	79
80					All On-Peak kW	8.15	/kW	All On-Peak kW	9.176	/kW	1.02609	/kW	80
81					All On-Peak kWh	0.05150	/kWh	All On-Peak kWh	0.05796	/kWh	0.00646	/kWh	81
82					All Off-Peak kWh	0.03784	/kWh	All Off-Peak kWh	0.04260	/kWh	0.00476	/kWh	82
83													83
84			Minimum	Sum & Win	Minimum	$ 0.493	/day	Basic Service Charge	$ 0.509	/day	$ 0.01600	/day	84

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
85													85
86	ET-SP	Residential Service	Rate	Super Peak	PROPOSED NEW SCHEDULE			Basic Service Charge	$ 0.509	/day	$ 0.50900	/day	86
87				Summer				All Super-Peak kWh	0.49465	/kWh	0.49465	/kWh	87
88		Time of Use						All On-Peak kWh	0.24465	/kWh	0.24465	/kWh	88
89								All Off-Peak kWh	0.05259	/kWh	0.05259	/kWh	89
90													90
91				Summer				Basic Service Charge	$ 0.509	/day	$ 0.50900	/day	91
92								All On-Peak kWh	0.24465	/kWh	0.24465	/kWh	92
93								All Off-Peak kWh	0.05259	/kWh	0.05259	/kWh	93
94													94
95				Winter				Basic Service Charge	$ 0.509	/day	$ 0.50900	/day	95
96								All On-Peak kWh	0.19642	/kWh	0.19642	/kWh	96
97								All Off-Peak kWh	0.05259	/kWh	0.05259	/kWh	97
98				Sup. Pk. Sum,									98
99			Minimum	Sum & Win				Basic Service Charge	$ 0.509	/day	$ 0.50900	/day	99
100													100
101	E-20	General Service	Rate	Summer	Basic Service Charge	$ 0.941	/day	Basic Service Charge	$ 1.160	/day	$ 0.21869	/day	101
102		Time of Use for			All On-Peak kW	2.112	/kW	All On-Peak kW	2.368	/kW	0.25555	/kW	102
103		Religious Houses of			Excess Off-Peak kW	1.056	/kW	Excess Off-Peak kW	1.184	/kW	0.12778	/kWh	103
104		Worship			All On-Peak kWh	0.12704	/kWh	All On-Peak kWh	0.14241	/kWh	0.01537	/kWh	104
105					All Off-Peak kWh	0.06136	/kWh	All Off-Peak kWh	0.06878	/kWh	0.00742	/kWh	105
106													106
107				Winter	Basic Service Charge	$ 0.941	/day	Basic Service Charge	$ 1.160	/day	$ 0.21869	/day	107
108					All On-Peak kW	1.905	/kW	All On-Peak kW	2.136	/kW	0.23051	/kW	108
109					Excess Off-Peak kW	0.953	/kW	Excess Off-Peak kW	1.068	/kW	0.11531	/kWh	109
110					All On-Peak kWh	0.11170	/kWh	All On-Peak kWh	0.12522	/kWh	0.01352	/kWh	110
111					All Off-Peak kWh	0.05500	/kWh	All Off-Peak kWh	0.06166	/kWh	0.00666	/kWh	111
112													112
113			Minimum	Sum & Win	Basic Service Charge	$ 0.941	/day	Basic Service Charge	$ 1.160	/day	$ 0.21869	/day	113
114					Demand Charge	1.724	/kW	Demand Charge	1.933	/kW	0.20850	/kW	114
115													115
116	E-21	General Service	Rate	Summer	RATE E-21 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU			RATE E-21 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU					116
117		Time of Use											117
118		Less Than 100 kW											118
119													119
120													120
121													121
122				Winter									122
123													123
124													124
125													125
126													126
127													127
128			Minimum	Sum & Win									128
129													129

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
130													130
131	E-22	Small General Service	Rate	Summer									131
132		Time of Use											132
133													133
134													134
135													135
136													136
137				Winter	RATE E-22 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU			RATE E-22 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU					137
138													138
139													139
140													140
141													141
142													142
143			Minimum	Sum & Win									143
144													144
145													145
146	E-23	Medium General Service	Rate	Summer									146
147		Time of Use											147
148													148
149													149
150													150
151													151
152				Winter	RATE E-23 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU			RATE E-23 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU					152
153													153
154													154
155													155
156													156
157													157
158			Minimum	Sum & Win									158
159													159
160													160
161	E-24	Large General Service	Rate	Summer									161
162		Time of Use											162
163													163
164													164
165													165
166													166
167				Winter	RATE E-24 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU			RATE E-24 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO E-32TOU					167
168													168
169													169
170													170
171													171
172													172
173			Minimum	Sum & Win									173
174													174

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Staff Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (I) - (F)		Line No.
175													175
176	E-30	Extra Small General	Rate	Summer	Basic Service Charge	$ 0.275	/day	Basic Service Charge	$ 0.339	/day	$ 0.06391	/day	176
177		Service Unmetered			All kWh	0.12782	/kWh	All kWh	0.13300	/kWh	0.00518	/kWh	177
178													178
179				Winter	Basic Service Charge	$ 0.275	/day	Basic Service Charge	$ 0.339	/day	$ 0.06391	/day	179
180					All kWh	0.11472	/kWh	All kWh	0.11937	/kWh	0.00465	/kWh	180
181													181
182	E-32 XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.577	/day	$ 0.00150	/day	182
183	(Presently	20 kW or Less			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.122	/day	(0.01221)	/day	183
184	E-32)				BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.870	/day	(0.05617)	/day	184
185					First 5,000 kWh: Secondary	0.11438	/kWh	First 5,000 kWh: Secondary	0.13207	/kWh	0.01769	/kWh	185
186					All remaining kWh: Secondary	0.06254	/kWh	All remaining kWh: Secondary	0.07443	/kWh	0.01189	/kWh	186
187					First 5,000 kWh: Primary	0.11160	/kWh	First 5,000 kWh: Primary	0.11158	/kWh	(0.00002)	/kWh	187
188					All remaining kWh: Primary	0.05875	/kWh	All remaining kWh: Primary	0.06887	/kWh	0.00921	/kWh	188
189													189
190				Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.577	/day	$ 0.00150	/day	190
191					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.122	/day	(0.01221)	/day	191
192					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.870	/day	(0.05617)	/day	192
193					First 5,000 kWh: Secondary	0.09929	/kWh	First 5,000 kWh: Secondary	0.11087	/kWh	0.01158	/kWh	193
194					All remaining kWh: Secondary	0.04745	/kWh	All remaining kWh: Secondary	0.05333	/kWh	0.00588	/kWh	194
195					First 5,000 kWh: Primary	0.09651	/kWh	First 5,000 kWh: Primary	0.10551	/kWh	0.00900	/kWh	195
196					All remaining kWh: Primary	0.04467	/kWh	All remaining kWh: Primary	0.04787	/kWh	0.00320	/kWh	196
197													197
198			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.577	/day	$ 0.00150	/day	198
199					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.122	/day	(0.01221)	/day	199
200					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.870	/day	(0.05617)	/day	200

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
201													201
202	E-32 S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46880	/day	202
203	(Presently	21-100 kW			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	203
204	E-32)				BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	204
205					First 100 kW: Secondary	8.477	/kW	First 100 kW: Secondary	7.372	/kW	(1.10539)	/kW	205
206					All remaining kW: Secondary	4.509	/kW	All remaining kW: Secondary	3.708	/kW	(0.80125)	/kW	206
207					First 100 kW: Primary	7.865	/kW	First 100 kW: Primary	5.748	/kW	(2.11746)	/kW	207
208					All remaining kW: Primary	3.897	/kW	All remaining kW: Primary	2.084	/kW	(1.81331)	/kW	208
209					First 200 kWh per kW	0.09115	/kWh	First 200 kWh per kW	0.10879	/kWh	0.01764	/kWh	209
210					All remaining kWh	0.05330	/kWh	All remaining kWh	0.06346	/kWh	0.01016	/kWh	210
211													211
212			Rate	Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46880	/day	212
213					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	213
214					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	214
215					First 100 kW: Secondary	8.477	/kW	First 100 kW: Secondary	7.372	/kW	(1.10539)	/kW	215
216					All remaining kW: Secondary	4.509	/kW	All remaining kW: Secondary	3.708	/kW	(0.80125)	/kW	216
217					First 100 kW: Primary	7.865	/kW	First 100 kW: Primary	5.748	/kW	(2.11746)	/kW	217
218					All remaining kW: Primary	3.897	/kW	All remaining kW: Primary	2.084	/kW	(1.81331)	/kW	218
219					First 200 kWh per kW	0.07613	/kWh	First 200 kWh per kW	0.09080	/kWh	0.01467	/kWh	219
220					All remaining kWh	0.03828	/kWh	All remaining kWh	0.04548	/kWh	0.00720	/kWh	220
221													221
222			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46880	/day	222
223					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	223
224					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	224
225					Minimum Demand Charge:	1.910	/kW	Minimum Demand Charge:	2.094	/kW	0.18400	/kW	225

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Staff Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
226													226
227	E-32 M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46680	/day	227
228	(Presently	101- 400 kW			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	228
229	E-32)				BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	229
230					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	230
231					First 100 kW: Secondary	8.477	/kW	First 100 kW: Secondary	8.200	/kW	(0.27722)	/kW	231
232					All remaining kW: Secondary	4.509	/kW	All remaining kW: Secondary	4.136	/kW	(0.37302)	/kW	232
233					First 100 kW: Primary	7.865	/kW	First 100 kW: Primary	7.388	/kW	(0.47689)	/kW	233
234					All remaining kW: Primary	3.897	/kW	All remaining kW: Primary	3.324	/kW	(0.57269)	/kW	234
235					First 100 kW: Transmission	6.132	/kW	First 100 kW: Transmission	2.737	/kW	(3.39484)	/kW	235
236					All remaining kW: Transmission	2.164	/kW	All remaining kW: Transmission	0.127	/kW	(2.03719)	/kW	236
237					First 200 kWh per kW	0.09115	/kWh	First 200 kWh per kW	0.10163	/kWh	0.01048	/kWh	237
238					All remaining kWh	0.05330	/kWh	All remaining kWh	0.05984	/kWh	0.00654	/kWh	238
239													239
240			Rate	Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46680	/day	240
241					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.587	/day	0.45309	/day	241
242					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 3.335	/day	0.40912	/day	242
243					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	$ 22.353	/day	(0.06916)	/day	243
244					First 100 kW: Secondary	8.477	/kW	First 100 kW: Secondary	$ 8.200	/kW	(0.27722)	/kW	244
245					All remaining kW: Secondary	4.509	/kW	All remaining kW: Secondary	$ 4.136	/kW	(0.37302)	/kW	245
246					First 100 kW: Primary	7.865	/kW	First 100 kW: Primary	$ 7.388	/kW	(0.47689)	/kW	246
247					All remaining kW: Primary	3.897	/kW	All remaining kW: Primary	$ 3.324	/kW	(0.57269)	/kW	247
248					First 100 kW: Transmission	6.132	/kW	First 100 kW: Transmission	0.085	/kW	(6.04595)	/kW	248
249					All remaining kW: Transmission	2.164	/kW	All remaining kW: Transmission	0.043	/kW	(2.12075)	/kW	249
250					First 200 kWh per kW	0.07613	/kWh	First 200 kWh per kW	0.08505	/kWh	0.00892	/kWh	250
251					All remaining kWh	0.03828	/kWh	All remaining kWh	0.04325	/kWh	0.00497	/kWh	251
252													252
253			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.068	/day	$ 0.49300	/day	253
254					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	254
255					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	255
256					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	256
257					Minimum Demand Charge:	1.910	/kW	Minimum Demand Charge:	2.330	/kW	0.42000	/kW	257
258													258
259	E-32 L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46680	/day	259
260	(Presently	401 kW and above			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	260
261	E-32)				BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	261
262					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	262
263					First 100 kW: Secondary	8.477	/kW	First 100 kW: Secondary	8.496	/kW	0.01932	/kW	263
264					All remaining kW: Secondary	4.509	/kW	All remaining kW: Secondary	4.278	/kW	(0.23060)	/kW	264
265					First 100 kW: Primary	7.865	/kW	First 100 kW: Primary	7.933	/kW	0.06750	/kW	265
266					All remaining kW: Primary	3.897	/kW	All remaining kW: Primary	3.715	/kW	(0.18242)	/kW	266
267					First 100 kW: Transmission	6.132	/kW	First 100 kW: Transmission	3.034	/kW	(3.09830)	/kW	267
268					All remaining kW: Transmission	2.164	/kW	All remaining kW: Transmission	0.269	/kW	(1.89477)	/kW	268
269					First 200 kWh per kW	0.09115	/kWh	First 200 kWh per kW	0.09869	/kWh	0.00754	/kWh	269
270					All remaining kWh	0.05330	/kWh	All remaining kWh	0.05963	/kWh	0.00633	/kWh	270
271													271
272			Rate	Winter	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46680	/day	272
273					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.587	/day	0.45309	/day	273
274					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 3.335	/day	0.40912	/day	274
275					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	$ 22.353	/day	(0.06916)	/day	275
276					First 100 kW: Secondary	8.477	/kW	First 100 kW: Secondary	$ 8.496	/kW	0.01932	/kW	276
277					All remaining kW: Secondary	4.509	/kW	All remaining kW: Secondary	$ 4.278	/kW	(0.23060)	/kW	277
278					First 100 kW: Primary	7.865	/kW	First 100 kW: Primary	$ 7.933	/kW	0.06750	/kW	278
279					All remaining kW: Primary	3.897	/kW	All remaining kW: Primary	$ 3.715	/kW	(0.18242)	/kW	279
280					First 100 kW: Transmission	6.132	/kW	First 100 kW: Transmission	$ 3.034	/kW	(3.09830)	/kW	280
281					All remaining kW: Transmission	2.164	/kW	All remaining kW: Transmission	$ 0.269	/kW	(1.89477)	/kW	281
282					First 200 kWh per kW	0.07613	/kWh	First 200 kWh per kW	0.08319	/kWh	0.00706	/kWh	282
283					All remaining kWh	0.03828	/kWh	All remaining kWh	0.04413	/kWh	0.00585	/kWh	283
284													284
285			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 1.042	/day	$ 0.46680	/day	285
286					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.587	/day	0.45309	/day	286
287					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 3.335	/day	0.40912	/day	287
288					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	$ 22.353	/day	(0.06916)	/day	288
289					Minimum Demand Charge:	1.910	/kW	Minimum Demand Charge:	2.414	/kW	0.50400	/kW	289

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
290													290
291	E-32R	Partial Requirements	Rate	Sum & Win	Billed on Rate E-32 or Rate E-32TOU			RATE E-32R PROPOSE TO CANCEL;					291
292		General Service						CUSTOMERS MOVE TO E-56					292
293			Minimum	Sum & Win	Includes contract minimums in kW determination								293
294													294
295	E-32TOU XS	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.606	/day	BSC: Self-Contained Meters	$ 0.609	/day	$ 0.00069	/day	295
296	(Presently	Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.122	/day	(0.01221)	/day	296
297	E-32TOU)	20 kW or Less			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	2.870	/day	(0.05617)	/day	297
298					First 5,000 On-Peak kWh: Secondary	0.14329	/kWh	First 5,000 On-Peak kWh: Secondary	0.16728	/kWh	0.02399	/kWh	298
299					All remaining On-Peak kWh: Secondary	0.07118	/kWh	All remaining On-Peak kWh: Secondary	0.08015	/kWh	0.00897	/kWh	299
300					First 5,000 Off-Peak kWh: Secondary	0.10607	/kWh	First 5,000 Off-Peak kWh: Secondary	0.12247	/kWh	0.01640	/kWh	300
301					All remaining Off-Peak kWh: Secondary	0.03849	/kWh	All remaining Off-Peak kWh: Secondary	0.04086	/kWh	0.00237	/kWh	301
302					First 5,000 On-Peak kWh: Primary	0.14047	/kWh	First 5,000 On-Peak kWh: Primary	0.16523	/kWh	0.02476	/kWh	302
303					All remaining On-Peak kWh: Primary	0.06770	/kWh	All remaining On-Peak kWh: Primary	0.07811	/kWh	0.01041	/kWh	303
304					First 5,000 Off-Peak kWh: Primary	0.10325	/kWh	First 5,000 Off-Peak kWh: Primary	0.12042	/kWh	0.01717	/kWh	304
305					All remaining Off-Peak kWh: Primary	0.03567	/kWh	All remaining Off-Peak kWh: Primary	0.03881	/kWh	0.00314	/kWh	305
306													306
307				Winter	BSC: Self-Contained Meters	$ 0.606	/day	BSC: Self-Contained Meters	$ 0.609	/day	$ 0.00069	/day	307
308					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.122	/day	(0.01221)	/day	308
309					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 2.870	/day	(0.05617)	/day	309
310					First 5,000 On-Peak kWh: Secondary	0.12847	/kWh	First 5,000 On-Peak kWh: Secondary	0.14950	/kWh	0.02103	/kWh	310
311					All remaining On-Peak kWh: Secondary	0.05633	/kWh	All remaining On-Peak kWh: Secondary	0.06232	/kWh	0.00599	/kWh	311
312					First 5,000 Off-Peak kWh: Secondary	0.09124	/kWh	First 5,000 Off-Peak kWh: Secondary	0.10469	/kWh	0.01345	/kWh	312
313					All remaining Off-Peak kWh: Secondary	0.02766	/kWh	All remaining Off-Peak kWh: Secondary	0.02788	/kWh	0.00022	/kWh	313
314					First 5,000 On-Peak kWh: Primary	0.12565	/kWh	First 5,000 On-Peak kWh: Primary	0.14745	/kWh	0.02180	/kWh	314
315					All remaining On-Peak kWh: Primary	0.05285	/kWh	All remaining On-Peak kWh: Primary	0.06027	/kWh	0.00742	/kWh	315
316					First 5,000 Off-Peak kWh: Primary	0.08842	/kWh	First 5,000 Off-Peak kWh: Primary	0.10264	/kWh	0.01422	/kWh	316
317					All remaining Off-Peak kWh: Primary	0.02484	/kWh	All remaining Off-Peak kWh: Primary	0.02583	/kWh	0.00099	/kWh	317
318													318
319			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 0.609	/day	$ 0.00069	/day	319
320					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.122	/day	(0.01221)	/day	320
321					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 2.870	/day	(0.05617)	/day	321

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I - F)	(L)	Line No.
322													322
323	E-32TOU S	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	323
324	(Presently	Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	324
325	E-32TOU)	21-100 kW			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	325
326					First 100 On-Peak kW: Secondary	12.400	/kW	First 100 On-Peak kW: Secondary	12.287	/kW	(0.11301)	/kW	326
327					All remaining On-Peak kW: Secondary	8.420	/kW	All remaining On-Peak kW: Secondary	7.539	/kW	(0.88061)	/kW	327
328					First 100 Off-Peak kW: Secondary	4.755	/kW	First 100 Off-Peak kW: Secondary	5.296	/kW	0.54081	/kW	328
329					All remaining Off-Peak kW: Secondary	2.648	/kW	All remaining Off-Peak kW: Secondary	2.942	/kW	0.29401	/kW	329
330					First 100 On-Peak kW: Primary	12.002	/kW	First 100 On-Peak kW: Primary	$ 10.824	/kW	(1.17621)	/kW	330
331					All remaining On-Peak kW: Primary	8.361	/kW	All remaining On-Peak kW: Primary	$ 6.808	/kW	(1.55321)	/kW	331
332					First 100 Off-Peak kW: Primary	4.256	/kW	First 100 Off-Peak kW: Primary	$ 4.613	/kW	0.35699	/kW	332
333					All remaining Off-Peak kW: Primary	2.579	/kW	All remaining Off-Peak kW: Primary	2.552	/kW	(0.02718)	/kW	333
334					All On-Peak kWh:	0.06312	/kWh	All On-Peak kWh:	0.07343	/kWh	0.01031	/kWh	334
335					All Off-Peak kWh:	0.05016	/kWh	All Off-Peak kWh:	0.05826	/kWh	0.00810	/kWh	335
336													336
337				Winter	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	337
338					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.587	/day	0.45309	/day	338
339					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 3.335	/day	0.40912	/day	339
340					First 100 On-Peak kW: Secondary	12.400	/kW	First 100 On-Peak kW: Secondary	12.287	/kW	(0.11301)	/kW	340
341					All remaining On-Peak kW: Secondary	8.420	/kW	All remaining On-Peak kW: Secondary	7.539	/kW	(0.88061)	/kW	341
342					First 100 Off-Peak kW: Secondary	4.755	/kW	First 100 Off-Peak kW: Secondary	5.296	/kW	0.54081	/kW	342
343					All remaining Off-Peak kW: Secondary	2.648	/kW	All remaining Off-Peak kW: Secondary	2.942	/kW	0.29401	/kW	343
344					First 100 On-Peak kW: Primary	12.002	/kW	First 100 On-Peak kW: Primary	$ 10.824	/kW	(1.17621)	/kW	344
345					All remaining On-Peak kW: Primary	8.361	/kW	All remaining On-Peak kW: Primary	$ 6.808	/kW	(1.55321)	/kW	345
346					First 100 Off-Peak kW: Primary	4.256	/kW	First 100 Off-Peak kW: Primary	$ 4.613	/kW	0.35699	/kW	346
347					All remaining Off-Peak kW: Primary	2.579	/kW	All remaining Off-Peak kW: Primary	2.552	/kW	(0.02718)	/kW	347
348					All On-Peak kWh:	0.04836	/kWh	All On-Peak kWh:	0.05734	/kWh	0.00898	/kWh	348
349					All Off-Peak kWh:	0.03540	/kWh	All Off-Peak kWh:	0.04184	/kWh	0.00644	/kWh	349
350													350
351			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	351
352					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	$ 1.587	/day	0.45309	/day	352
353					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	$ 3.335	/day	0.40912	/day	353
354					Minimum Demand Charge:	1.910	/kW	Minimum Demand Charge:	2.150	/kW	0.24000	/kW	354

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
355													355
356	E-32TOU M	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	356
357	(Presently	Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	357
358	E-32TOU)	101- 400 kW			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	358
359					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	359
360					First 100 On-Peak kW: Secondary	12.400	/kW	First 100 On-Peak kW: Secondary	12.933	/kW	0.53275	/kW	360
361					All remaining On-Peak kW: Secondary	8.420	/kW	All remaining On-Peak kW: Secondary	7.652	/kW	(0.76843)	/kW	361
362					First 100 Residual kW: Secondary	4.755	/kW	First 100 Off-Peak kW: Secondary	5.573	/kW	0.81785	/kW	362
363					All remaining Residual kW: Secondary	2.648	/kW	All remaining Off-Peak kW: Secondary	2.922	/kW	0.27353	/kW	363
364					First 100 On-Peak kW: Primary	12.002	/kW	First 100 On-Peak kW: Primary	11.470	/kW	(0.53245)	/kW	364
365					All remaining On-Peak kW: Primary	8.361	/kW	All remaining On-Peak kW: Primary	6.920	/kW	(1.44103)	/kW	365
366					First 100 Residual kW: Primary	4.256	/kW	First 100 Off-Peak kW: Primary	4.890	/kW	0.63402	/kW	366
367					All remaining Residual kW: Primary	2.579	/kW	All remaining Off-Peak kW: Primary	2.531	/kW	(0.04766)	/kW	367
368					First 100 On-Peak kW: Transmission	11.291	/kW	First 100 On-Peak kW: Transmission	6.104	/kW	(5.18652)	/kW	368
369					All remaining On-Peak kW: Transmission	8.116	/kW	All remaining On-Peak kW: Transmission	4.608	/kW	(3.50789)	/kW	369
370					First 100 Residual kW: Transmission	3.693	/kW	First 100 Off-Peak kW: Transmission	3.427	/kW	(0.26618)	/kW	370
371					All remaining Residual kW: Transmission	2.486	/kW	All remaining Off-Peak kW: Transmission	1.751	/kW	(0.73504)	/kW	371
372					All On-Peak kWh:	0.06312	/kWh	All On-Peak kWh:	0.07496	/kWh	0.01186	/kWh	372
373					All Off-Peak kWh:	0.05016	/kWh	All Off-Peak kWh:	0.05849	/kWh	0.00833	/kWh	373
374													374
375				Winter	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	375
376					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	376
377					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	377
378					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	378
379					First 100 On-Peak kW: Secondary	12.400	/kW	First 100 On-Peak kW: Secondary	12.933	/kW	0.53275	/kW	379
380					All remaining On-Peak kW: Secondary	8.420	/kW	All remaining On-Peak kW: Secondary	7.652	/kW	(0.76843)	/kW	380
381					First 100 Residual kW: Secondary	4.755	/kW	First 100 Off-Peak kW: Secondary	5.573	/kW	0.81785	/kW	381
382					All remaining Residual kW: Secondary	2.648	/kW	All remaining Off-Peak kW: Secondary	2.922	/kW	0.27353	/kW	382
383					First 100 On-Peak kW: Primary	12.002	/kW	First 100 On-Peak kW: Primary	11.470	/kW	(0.53245)	/kW	383
384					All remaining On-Peak kW: Primary	8.361	/kW	All remaining On-Peak kW: Primary	6.920	/kW	(1.44103)	/kW	384
385					First 100 Residual kW: Primary	4.256	/kW	First 100 Off-Peak kW: Primary	4.890	/kW	0.63402	/kW	385
386					All remaining Residual kW: Primary	2.579	/kW	All remaining Off-Peak kW: Primary	2.531	/kW	(0.04766)	/kW	386
387					First 100 On-Peak kW: Transmission	11.291	/kW	First 100 On-Peak kW: Transmission	6.104	/kW	(5.18652)	/kW	387
388					All remaining On-Peak kW: Transmission	8.116	/kW	All remaining On-Peak kW: Transmission	4.608	/kW	(3.50789)	/kW	388
389					First 100 Residual kW: Transmission	3.693	/kW	First 100 Off-Peak kW: Transmission	3.427	/kW	(0.26618)	/kW	389
390					All remaining Residual kW: Transmission	2.486	/kW	All remaining Off-Peak kW: Transmission	1.751	/kW	(0.73504)	/kW	390
391					All On-Peak kWh:	0.04836	/kWh	All On-Peak kWh:	0.05734	/kWh	0.00898	/kWh	391
392					All Off-Peak kWh:	0.03540	/kWh	All Off-Peak kWh:	0.04184	/kWh	0.00644	/kWh	392
393													393
394			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	394
395					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	395
396					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	396
397					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	397
398					Minimum Demand Charge:	1.910	/kW	Minimum Demand Charge:	2.138	/kW	0.22800	/kW	398

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
399													399
400	E-32TOU L	General Service	Rate	Summer	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	400
401	(Presently	Time of Use			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	401
402	E-32TOU)	401 kW and above			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	402
403					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	403
404					First 100 On-Peak kW: Secondary	12.400	/kW	First 100 On-Peak kW: Secondary	13.286	/kW	0.88587	/kW	404
405					All remaining On-Peak kW: Secondary	8.420	/kW	All remaining On-Peak kW: Secondary	7.904	/kW	(0.51579)	/kW	405
406					First 100 Residual kW: Secondary	4.755	/kW	First 100 Off-Peak kW: Secondary	5.435	/kW	0.68030	/kW	406
407					All remaining Residual kW: Secondary	2.648	/kW	All remaining Off-Peak kW: Secondary	2.970	/kW	0.32230	/kW	407
408					First 100 On-Peak kW: Primary	12.002	/kW	First 100 On-Peak kW: Primary	11.823	/kW	(0.17933)	/kW	408
409					All remaining On-Peak kW: Primary	8.361	/kW	All remaining On-Peak kW: Primary	7.173	/kW	(1.18839)	/kW	409
410					First 100 Residual kW: Primary	4.256	/kW	First 100 Off-Peak kW: Primary	4.752	/kW	0.49648	/kW	410
411					All remaining Residual kW: Primary	2.579	/kW	All remaining Off-Peak kW: Primary	2.580	/kW	0.00111	/kW	411
412					First 100 On-Peak kW: Transmission	11.291	/kW	First 100 On-Peak kW: Transmission	6.458	/kW	(4.83341)	/kW	412
413					All remaining On-Peak kW: Transmission	8.116	/kW	All remaining On-Peak kW: Transmission	4.861	/kW	(3.25525)	/kW	413
414					First 100 Residual kW: Transmission	3.693	/kW	First 100 Off-Peak kW: Transmission	3.289	/kW	(0.40372)	/kW	414
415					All remaining Residual kW: Transmission	2.486	/kW	All remaining Off-Peak kW: Transmission	1.800	/kW	(0.68626)	/kW	415
416					All On-Peak kWh:	0.06312	/kWh	All On-Peak kWh:	0.07484	/kWh	0.01172	/kWh	416
417					All Off-Peak kWh:	0.05016	/kWh	All Off-Peak kWh:	0.05937	/kWh	0.00921	/kWh	417
418													418
419				Winter	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	419
420					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	420
421					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	421
422					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	422
423					First 100 On-Peak kW: Secondary	12.400	/kW	First 100 On-Peak kW: Secondary	13.286	/kW	0.88587	/kW	423
424					All remaining On-Peak kW: Secondary	8.420	/kW	All remaining On-Peak kW: Secondary	7.904	/kW	(0.51579)	/kW	424
425					First 100 Residual kW: Secondary	4.755	/kW	First 100 Off-Peak kW: Secondary	5.435	/kW	0.68030	/kW	425
426					All remaining Residual kW: Secondary	2.648	/kW	All remaining Off-Peak kW: Secondary	2.970	/kW	0.32230	/kW	426
427					First 100 On-Peak kW: Primary	12.002	/kW	First 100 On-Peak kW: Primary	11.823	/kW	(0.17933)	/kW	427
428					All remaining On-Peak kW: Primary	8.361	/kW	All remaining On-Peak kW: Primary	7.173	/kW	(1.18839)	/kW	428
429					First 100 Residual kW: Primary	4.256	/kW	First 100 Off-Peak kW: Primary	4.752	/kW	0.49648	/kW	429
430					All remaining Residual kW: Primary	2.579	/kW	All remaining Off-Peak kW: Primary	2.580	/kW	0.00111	/kW	430
431					First 100 On-Peak kW: Transmission	11.291	/kW	First 100 On-Peak kW: Transmission	6.458	/kW	(4.83341)	/kW	431
432					All remaining On-Peak kW: Transmission	8.116	/kW	All remaining On-Peak kW: Transmission	4.861	/kW	(3.25525)	/kW	432
433					First 100 Residual kW: Transmission	3.693	/kW	First 100 Off-Peak kW: Transmission	3.289	/kW	(0.40372)	/kW	433
434					All remaining Residual kW: Transmission	2.486	/kW	All remaining Off-Peak kW: Transmission	1.800	/kW	(0.68626)	/kW	434
435					All On-Peak kWh:	0.04836	/kWh	All On-Peak kWh:	0.05722	/kWh	0.00886	/kWh	435
436					All Off-Peak kWh:	0.03540	/kWh	All Off-Peak kWh:	0.04176	/kWh	0.00636	/kWh	436
437													437
438			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 1.074	/day	$ 0.46599	/day	438
439					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.587	/day	0.45309	/day	439
440					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.335	/day	0.40912	/day	440
441					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	22.353	/day	(0.06916)	/day	441
442					Minimum Demand Charge:	1.910	/kW	Minimum Demand Charge:	2.132	/kW	0.22200	/kW	442

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES

COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F)	(G)	(H) Staff Proposed Rates Block	(I)	(J)	(K) Change (I) - (F)	(L)	Line No.
443													443
444	E-34	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.709	/day	$ 0.13363	/day	444
445		General Service			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.398	/day	0.26354	/day	445
446					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.606	/day	0.68000	/day	446
447					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	27.633	/day	5.21087	/day	447
448					All kW: Secondary	15.297	/kW	All kW: Secondary	17.164	/kW	1.86746	/kW	448
449					All kW: Primary	14.507	/kW	All kW: Primary	16.278	/kW	1.77101	/kW	449
450					All kW: Primary on Military Bases	11.257	/kW	All kW: Primary on Military Bases	11.868	/kW	0.61124	/kW	450
451					All kW: Transmission	10.577	/kW	All kW: Transmission	12.631	/kW	2.05425	/kW	451
452					All kWh	0.03715	/kWh	All kWh	0.04169	/kWh	0.00454	/kWh	452
453													453
454			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.575	/day	BSC: Self-Contained Meters	$ 0.709	/day	$ 0.13363	/day	454
455					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.398	/day	0.26354	/day	455
456					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.606	/day	0.68000	/day	456
457					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	27.633	/day	5.21087	/day	457
458					Demand Charge: Secondary	15.297	/kW	Demand Charge: Secondary	17.164	/kW	1.86746	/kW	458
459					Demand Charge: Primary	14.507	/kW	Demand Charge: Primary	16.278	/kW	1.77101	/kW	459
460					Demand Charge: Primary on Military Bases	11.257	/kW	Demand Charge: Primary on Military Bases	11.868	/kW	0.61124	/kW	460
461					Demand Charge: Transmission	10.577	/kW	Demand Charge: Transmission	12.631	/kW	2.05425	/kW	461
462													462
463	E-35	Extra Large	Rate	Sum & Win	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 0.749	/day	$ 0.14130	/day	463
464		General Service			BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.398	/day	0.26354	/day	464
465		Time Of Use			BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.606	/day	0.68000	/day	465
466					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	27.633	/day	5.21087	/day	466
467					All On-Peak kW: Secondary	13.313	/kW	All On-Peak kW: Secondary	14.887	/kW	1.57440	/kW	467
468					All Excess Off-Peak kW: Secondary	2.412	/kW	All Off-Peak kW: Secondary	2.897	/kW	0.28524	/kW	468
469					All On-Peak kW: Primary	12.653	/kW	All On-Peak kW: Primary	14.149	/kW	1.49634	/kW	469
470					All Excess Off-Peak kW: Primary	2.346	/kW	All Off-Peak kW: Primary	2.623	/kW	0.27744	/kW	470
471					All On-Peak kW: Primary on Military Bases	10.163	/kW	All On-Peak kW: Primary on Military Bases	11.365	/kW	1.20188	/kW	471
472					All Excess Off-Peak kW: Primary on Military	2.096	/kW	All Off-Peak kW: Primary on Military Bases	2.344	/kW	0.24787	/kW	472
473					All On-Peak kW: Trans.	9.248	/kW	All On-Peak kW: Transmission	10.342	/kW	1.09367	/kW	473
474					All Excess Off-Peak kW: Trans.	2.005	/kW	All Off-Peak kW: Transmission	2.242	/kW	0.23711	/kW	474
475					All On-Peak kWh	0.04141	/kWh	All On-Peak kWh	0.04631	/kWh	0.00490	/kWh	475
476					All Off-Peak kWh	0.03114	/kWh	All Off-Peak kWh	0.03482	/kWh	0.00368	/kWh	476
477													477
478			Minimum	Sum & Win	BSC: Self-Contained Meters	$ 0.608	/day	BSC: Self-Contained Meters	$ 0.749	/day	$ 0.14130	/day	478
479					BSC: Instrument-rated Meters	1.134	/day	BSC: Instrument-rated Meters	1.398	/day	0.26354	/day	479
480					BSC: Primary Meters	2.926	/day	BSC: Primary Meters	3.606	/day	0.68000	/day	480
481					BSC: Transmission Meters	22.422	/day	BSC: Transmission Meters	27.633	/day	5.21087	/day	481
482					Demand Charge: Secondary	13.313	/kW	Demand Charge: Secondary	14.887	/kW	1.57440	/kW	482
483					Demand Charge: Primary	12.653	/kW	Demand Charge: Primary	14.149	/kW	1.49634	/kW	483
484					Demand Charge: Primary on Military Bases	10.163	/kW	Demand Charge: Primary on Military Bases	11.365	/kW	1.20188	/kW	484
485					Demand Charge: Transmission	9.248	/kW	Demand Charge: Transmission	10.342	/kW	1.09367	/kW	485

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
486													486
487	E-36	Station Use Service	Rate	Sum & Win	Basic Service Charge	$ 5,100.00	/mo	Basic Service Charge	$ 4,930.00	/mo	$ (1,170.00)	/mo	487
488					Metering Charge Company Owned	1.29%		Metering Charge Company Owned	1.29%		-		488
489					Metering Charge Customer Owned	0.35%		Metering Charge Customer Owned	0.35%		-		489
490					All kW: Secondary	4.58	/kW	All kW: Secondary	4.577	/kW	(0.00300)	/kW	490
491					All kW: Primary	4.42	/kW	All kW: Primary	3.971	/kW	(0.44900)	/kW	491
492					All kW: Transmission	1.43	/kW	All kW: Transmission	0.207	/kW	(1.22300)	/kW	492
493					All kWh: Hourly Pricing Proxy plus	0.0005	/kWh	All kWh: Hourly Pricing Proxy plus	0.00050	/kWh	-	/kWh	493
494													494
495	E-38	Agricultural	Rate	Summer	RATE E-38 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE E-221.			RATE E-38 CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE E-221.					495
496		Irrigation Service											496
497													497
498													498
499													499
500				Winter									500
501													501
502													502
503													503
504			Minimum	Sum & Win									504
505													505
506													506
507		Customer Owned	Discount	Sum & Win									507
508		Transformer Option											508
509													509
510		Time of Week Option	Adjustment to Bill	Sum & Win									510
511													511
512													512
513													513
514	E-38-8T	Agricultural	Rate	Sum & Win	RATE E-38-8T CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE E-221-8T.			RATE E-38-8T CANCELLED PER A.C.C. DECISION NO. 69663; CUSTOMERS MOVED TO RATE E-221-8T.					514
515		Irrigation Service											515
516		Time of Use											516
517													517
518													518
519													519
520			Minimum	Sum & Win									520
521													521
522		Customer Owned											522
523		Transformer Option	Discount	Sum & Win									523

Supporting Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Staff Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (I) - (F)		Line No.
524													524
525	E-40	Agricultural Wind		Sum & Win	Service Charge $/HP	$ 0.043	/HP-day	Service Charge $/HP	$ 0.048	/HP-day	$ 0.00508	/day	525
526		Machine Service			All kWh	0.08073	/kWh	All kWh	0.08714	/kWh	0.00641	/kWh	526
527													527
528	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	FIXTURES (Company Owned)			FIXTURES (Company Owned)					528
529		Service			A. Acorn 9,500 HPS	$ 23.90	/mo	A. Acorn 9,500 HPS	$ 26.10	/mo	$ 2.19702	/mo	529
530					Acorn 16,000 HPS	26.53	/mo	Acorn 16,000 HPS	28.97	/mo	2.43879	/mo	530
531					B. Architectural 9,500 HPS	13.58	/mo	B. Architectural 9,500 HPS	14.83	/mo	1.24835	/mo	531
532					Architectural 16,000 HPS	15.86	/mo	Architectural 16,000 HPS	17.32	/mo	1.45794	/mo	532
533					Architectural 30,000 HPS	18.82	/mo	Architectural 30,000 HPS	20.55	/mo	1.73004	/mo	533
534					Architectural 50,000 HPS	23.22	/mo	Architectural 50,000 HPS	25.35	/mo	2.13451	/mo	534
535					Architectural 14,000 MH	19.00	/mo	Architectural 14,000 MH	20.75	/mo	1.74659	/mo	535
536					Architectural 21,000 MH	21.57	/mo	Architectural 21,000 MH	23.56	/mo	1.98264	/mo	536
537					Architectural 36,000 MH	26.97	/mo	Architectural 36,000 MH	29.45	/mo	2.47923	/mo	537
538					Architectural 8,000 LPS	19.74	/mo	Architectural 8,000 LPS	21.55	/mo	1.81000	/mo	538
539					Architectural 13,500 LPS	23.28	/mo	Architectural 13,500 LPS	25.42	/mo	2.14000	/mo	539
540					Architectural 22,500 LPS	26.59	/mo	Architectural 22,500 LPS	29.03	/mo	2.44000	/mo	540
541					Architectural 33,000 LPS	31.99	/mo	Architectural 33,000 LPS	34.93	/mo	2.94000	/mo	541
542					C. Cobra/Roadway 5,800 HPS	7.71	/mo	C. Cobra/Roadway 5,800 HPS	8.42	/mo	0.70875	/mo	542
543					Cobra/Roadway 9,500 HPS	9.06	/mo	Cobra/Roadway 9,500 HPS	9.91	/mo	0.83468	/mo	543
544					Cobra/Roadway 16,000 HPS	11.37	/mo	Cobra/Roadway 16,000 HPS	12.42	/mo	1.04519	/mo	544
545					Cobra/Roadway 30,000 HPS	13.71	/mo	Cobra/Roadway 30,000 HPS	14.97	/mo	1.26030	/mo	545
546					Cobra/Roadway 50,000 HPS	16.50	/mo	Cobra/Roadway 50,000 HPS	18.31	/mo	1.70982	/mo	546
547					Cobra/Roadway 14,000 MH	13.22	/mo	Cobra/Roadway 14,000 MH	14.44	/mo	1.21526	/mo	547
548					Cobra/Roadway 21,000 MH	15.45	/mo	Cobra/Roadway 21,000 MH	16.87	/mo	1.42025	/mo	548
549					Cobra/Roadway 36,000 MH	20.34	/mo	Cobra/Roadway 36,000 MH	22.21	/mo	1.86977	/mo	549
550					Cobra/Roadway 8,000 FL	15.19	/mo	Cobra/Roadway 8,000 FL	16.59	/mo	1.39635	/mo	550
551					D. Decorative Transit 9,500 HPS	32.76	/mo	D. Decorative Transit 9,500 HPS	35.77	/mo	3.01148	/mo	551
552					Decorative Transit 16,000 HPS	32.57	/mo	Decorative Transit 16,000 HPS	35.56	/mo	2.99402	/mo	552
553					Decorative Transit 30,000 HPS	37.50	/mo	Decorative Transit 30,000 HPS	40.95	/mo	3.44721	/mo	553
554					E. Flood 30,000 HPS	18.20	/mo	E. Flood 30,000 HPS	19.87	/mo	1.67305	/mo	554
555					Flood 50,000 HPS	22.57	/mo	Flood 50,000 HPS	24.64	/mo	2.07476	/mo	555
556					Flood 21,000 MH	19.43	/mo	Flood 21,000 MH	21.22	/mo	1.78611	/mo	556
557					Flood 36,000 MH	23.69	/mo	Flood 36,000 MH	25.87	/mo	2.17772	/mo	557
558					F. Post Top gray 8,000 FL	16.37	/mo	F. Post Top gray 8,000 FL	17.87	/mo	1.50482	/mo	558
559					Post Top gray 9,500 HPS	9.36	/mo	Post Top gray 9,500 HPS	10.22	/mo	0.86042	/mo	559
560					Post Top black 9,500 HPS	10.78	/mo	Post Top black 9,500 HPS	11.77	/mo	0.99096	/mo	560
561					Post Top Transit 9,500 HPS	28.88	/mo	Post Top Transit 9,500 HPS	31.32	/mo	2.63643	/mo	561
562					G. FROZEN 4,000 INC	8.54	/mo	G. FROZEN 4,000 INC	9.43	/mo	0.79424	/mo	562
563					FROZEN 7,000 MV	11.19	/mo	FROZEN 7,000 MV	12.22	/mo	1.02865	/mo	563
564					FROZEN 20,000 MV	22.01	/mo	FROZEN 20,000 MV	24.03	/mo	2.02328	/mo	564
565					FROZEN Brackets 8ft to 16ft	1.52	/mo	FROZEN Brackets 8ft to 16ft	1.66	/mo	0.13973	/mo	565
566					FIXTURES (Customer Owned)			FIXTURES (Customer Owned)					566
567					A. Acorn 9,500 HPS	$ 8.14	/mo	A. Acorn 9,500 HPS	8.89	/mo	$ 0.74827	/mo	567
568					Acorn 16,000 HPS	10.29	/mo	Acorn 16,000 HPS	11.24	/mo	0.94591	/mo	568

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
569													569
570	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	FIXTURES (Customer Owned) (cont)			FIXTURES (Customer Owned) (cont)					570
571	(cont)	Service			B. Architectural 9,500 HPS	$ 6.48	/mo	B. Architectural 9,500 HPS	7.06	/mo	$ 0.58568	/mo	571
572		(cont)			Architectural 16,000 HPS	8.67	/mo	Architectural 16,000 HPS	9.47	/mo	0.79700	/mo	572
573					Architectural 30,000 HPS	11.13	/mo	Architectural 30,000 HPS	12.15	/mo	1.02313	/mo	573
574					Architectural 50,000 HPS	16.01	/mo	Architectural 50,000 HPS	17.48	/mo	1.47173	/mo	574
575					Architectural 14,000 MH	10.41	/mo	Architectural 14,000 MH	11.37	/mo	0.95695	/mo	575
576					Architectural 21,000 MH	12.84	/mo	Architectural 21,000 MH	14.02	/mo	1.18032	/mo	576
577					Architectural 36,000 MH	17.66	/mo	Architectural 36,000 MH	19.28	/mo	1.62341	/mo	577
578					Architectural 8,000 LPS	8.67	/mo	Architectural 8,000 LPS	9.47	/mo	0.79700	/mo	578
579					Architectural 13,500 LPS	10.46	/mo	Architectural 13,500 LPS	11.42	/mo	0.96154	/mo	579
580					Architectural 22,500 LPS	12.76	/mo	Architectural 22,500 LPS	13.93	/mo	1.17297	/mo	580
581					Architectural 33,000 LPS	15.03	/mo	Architectural 33,000 LPS	16.41	/mo	1.38164	/mo	581
582					C. Cobra/Roadway 5,800 HPS	4.56	/mo	C. Cobra/Roadway 5,800 HPS	4.98	/mo	0.41918	/mo	582
583					Cobra/Roadway 9,500 HPS	5.58	/mo	Cobra/Roadway 9,500 HPS	6.09	/mo	0.51294	/mo	583
584					Cobra/Roadway 16,000 HPS	7.79	/mo	Cobra/Roadway 16,000 HPS	8.51	/mo	0.71610	/mo	584
585					Cobra/Roadway 30,000 HPS	10.12	/mo	Cobra/Roadway 30,000 HPS	11.05	/mo	0.93029	/mo	585
586					Cobra/Roadway 50,000 HPS	14.46	/mo	Cobra/Roadway 50,000 HPS	15.79	/mo	1.32924	/mo	586
587					Cobra/Roadway 14,000 MH	9.01	/mo	Cobra/Roadway 14,000 MH	9.84	/mo	0.82825	/mo	587
588					Cobra/Roadway 21,000 MH	11.21	/mo	Cobra/Roadway 21,000 MH	12.24	/mo	1.03049	/mo	588
589					Cobra/Roadway 36,000 MH	15.57	/mo	Cobra/Roadway 36,000 MH	17.00	/mo	1.43128	/mo	589
590					Cobra/Roadway 8,000 FL	4.45	/mo	Cobra/Roadway 8,000 FL	4.86	/mo	0.40907	/mo	590
591					D. Decorative Transit 9,500 HPS	9.81	/mo	D. Decorative Transit 9,500 HPS	10.71	/mo	0.90179	/mo	591
592					Decorative Transit 16,000 HPS	5.57	/mo	Decorative Transit 16,000 HPS	6.08	/mo	0.51203	/mo	592
593					Decorative Transit 30,000 HPS	14.15	/mo	Decorative Transit 30,000 HPS	15.45	/mo	1.30075	/mo	593
594					E. Flood 30,000 HPS	11.31	/mo	E. Flood 30,000 HPS	12.35	/mo	1.03968	/mo	594
595					Flood 50,000 HPS	15.69	/mo	Flood 50,000 HPS	17.13	/mo	1.44231	/mo	595
596					Flood 21,000 MH	11.96	/mo	Flood 21,000 MH	13.05	/mo	1.09851	/mo	596
597					Flood 36,000 MH	16.21	/mo	Flood 36,000 MH	17.70	/mo	1.49011	/mo	597
598					F. Post Top gray 8,000 FL	4.62	/mo	F. Post Top gray 8,000 FL	5.04	/mo	0.42470	/mo	598
599					Post Top gray 9,500 HPS	5.87	/mo	Post Top gray 9,500 HPS	6.41	/mo	0.53960	/mo	599
600					Post Top black 9,500 HPS	6.08	/mo	Post Top black 9,500 HPS	6.64	/mo	0.55891	/mo	600
601					Post Top Transit 9,500 HPS	9.04	/mo	Post Top Transit 9,500 HPS	9.87	/mo	0.83101	/mo	601
602					G. FROZEN 4,000 INC	4.83	/mo	G. FROZEN 4,000 INC	5.27	/mo	0.44400	/mo	602
603					FROZEN 7,000 MV	6.42	/mo	FROZEN 7,000 MV	7.01	/mo	0.59018	/mo	603
604					FROZEN 20,000 MV	12.47	/mo	FROZEN 20,000 MV	13.62	/mo	1.14631	/mo	604
605					POLES			POLES					605
606					A. Anchor Flush, Round, 1X, 12ft	$ 10.75	/mo	A. Anchor Flush, Round, 1X, 12ft	11.74	/mo	$ 0.98820	/mo	606
607					Anchor Flush, Round, 1X, 22ft	12.10	/mo	Anchor Flush, Round, 1X, 22ft	13.21	/mo	1.11230	/mo	607
608					Anchor Flush, Round, 1X, 25ft	13.69	/mo	Anchor Flush, Round, 1X, 25ft	14.89	/mo	1.20331	/mo	608
609					Anchor Flush, Round, 1X, 30ft	15.04	/mo	Anchor Flush, Round, 1X, 30ft	16.42	/mo	1.38256	/mo	609
610					Anchor Flush, Round, 1X, 32ft	15.80	/mo	Anchor Flush, Round, 1X, 32ft	17.25	/mo	1.45242	/mo	610
611					Anchor Flush, Round, 2X, 12ft	11.46	/mo	Anchor Flush, Round, 2X, 12ft	12.51	/mo	1.05347	/mo	611
612					Anchor Flush, Round, 2X, 22ft	13.17	/mo	Anchor Flush, Round, 2X, 22ft	14.38	/mo	1.21066	/mo	612
613					Anchor Flush, Round, 2X, 25ft	13.73	/mo	Anchor Flush, Round, 2X, 25ft	14.99	/mo	1.26214	/mo	613
614					Anchor Flush, Round, 2X, 30ft	15.96	/mo	Anchor Flush, Round, 2X, 30ft	17.43	/mo	1.46713	/mo	614
615					Anchor Flush, Round, 2X, 32ft	17.03	/mo	Anchor Flush, Round, 2X, 32ft	18.60	/mo	1.56549	/mo	615
616					Anchor Flush, Square, 5", 13ft	12.32	/mo	Anchor Flush, Square, 5", 13ft	13.45	/mo	1.13252	/mo	616
617					Anchor Flush, Square, 5", 15ft	11.01	/mo	Anchor Flush, Square, 5", 15ft	12.02	/mo	1.01210	/mo	617
618					Anchor Flush, Square, 5", 23ft	13.06	/mo	Anchor Flush, Square, 5", 23ft	14.26	/mo	1.20056	/mo	618
619					Anchor Flush, Square, 5", 25ft	14.36	/mo	Anchor Flush, Square, 5", 25ft	15.68	/mo	1.32005	/mo	619
620					Anchor Flush, Square, 5", 28ft	15.94	/mo	Anchor Flush, Square, 5", 28ft	17.41	/mo	1.46529	/mo	620

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
621													621
622	E-47	Dusk to Dawn Lighting	Rate	Sum & Win	POLES (cont)			POLES (cont)					622
623	(cont)	Service			A. Anchor Flush, Square, 5", 32ft	$ 15.65	/mo	A. Anchor Flush, Square, 5", 32ft	17.31	/mo	$ 1.45702	/mo	623
624		(cont)			Anchor Flush, Concrete, 12ft	36.72	/mo	Anchor Flush, Concrete, 12ft	40.10	/mo	3.37551	/mo	624
625					Anchor Flush, Fiberglass, 12ft	31.10	/mo	Anchor Flush, Fiberglass, 12ft	33.96	/mo	2.85889	/mo	625
626					Anchor Flush, Dec Transit Ped, 4", 16ft	30.32	/mo	Anchor Flush, Dec Transit Ped, 4", 16ft	33.11	/mo	2.78718	/mo	626
627					Anchor Flush, Dec Transit, 5", 30ft	58.54	/mo	Anchor Flush, Dec Transit, 5", 30ft	63.92	/mo	5.38133	/mo	627
628					B. Anchor Pedstl, Round, 1X, 12ft	10.34	/mo	B. Anchor Pedstl, Round, 1X, 12ft	11.29	/mo	0.95051	/mo	628
629					Anchor Pedstl, Round, 1X, 22ft	11.69	/mo	Anchor Pedstl, Round, 1X, 22ft	12.76	/mo	1.07461	/mo	629
630					Anchor Pedstl, Round, 1X, 25ft	12.67	/mo	Anchor Pedstl, Round, 1X, 25ft	13.83	/mo	1.16470	/mo	630
631					Anchor Pedstl, Round, 1X, 30ft	14.64	/mo	Anchor Pedstl, Round, 1X, 30ft	15.98	/mo	1.34579	/mo	631
632					Anchor Pedstl, Round, 1X, 32ft	15.38	/mo	Anchor Pedstl, Round, 1X, 32ft	16.79	/mo	1.41382	/mo	632
633					Anchor Pedstl, Round, 2X, 12ft	11.05	/mo	Anchor Pedstl, Round, 2X, 12ft	12.07	/mo	1.01576	/mo	633
634					Anchor Pedstl, Round, 2X, 22ft	12.34	/mo	Anchor Pedstl, Round, 2X, 22ft	13.47	/mo	1.13436	/mo	634
635					Anchor Pedstl, Round, 2X, 25ft	13.32	/mo	Anchor Pedstl, Round, 2X, 25ft	14.54	/mo	1.22445	/mo	635
636					Anchor Pedstl, Round, 2X, 30ft	15.55	/mo	Anchor Pedstl, Round, 2X, 30ft	16.98	/mo	1.42944	/mo	636
637					Anchor Pedstl, Round, 2X, 32ft	16.61	/mo	Anchor Pedstl, Round, 2X, 32ft	18.14	/mo	1.52688	/mo	637
638					Anchor Pedstl, Round, 3 Bolt, 32ft	19.09	/mo	Anchor Pedstl, Round, 3 Bolt, 32ft	20.84	/mo	1.75486	/mo	638
639					Anchor Pedstl, Square, 5", 13ft	11.92	/mo	Anchor Pedstl, Square, 5", 13ft	13.02	/mo	1.09575	/mo	639
640					Anchor Pedstl, Square, 5", 15ft	12.19	/mo	Anchor Pedstl, Square, 5", 15ft	13.31	/mo	1.12057	/mo	640
641					Anchor Pedstl, Square, 5", 23ft	12.65	/mo	Anchor Pedstl, Square, 5", 23ft	13.81	/mo	1.16286	/mo	641
642					Anchor Pedstl, Square, 5", 25ft	13.95	/mo	Anchor Pedstl, Square, 5", 25ft	15.23	/mo	1.28236	/mo	642
643					Anchor Pedstl, Square, 5", 28ft	15.51	/mo	Anchor Pedstl, Square, 5", 28ft	16.94	/mo	1.42577	/mo	643
644					Anchor Pedstl, Square, 5", 32ft	16.10	/mo	Anchor Pedstl, Square, 5", 32ft	17.58	/mo	1.48000	/mo	644
645					C. Direct Bury, Round, 19ft	16.27	/mo	C. Direct Bury, Round, 19ft	17.77	/mo	1.49563	/mo	645
646					Direct Bury, Round, 30ft	12.70	/mo	Direct Bury, Round, 30ft	13.87	/mo	1.16746	/mo	646
647					Direct Bury, Round, 38ft	15.50	/mo	Direct Bury, Round, 38ft	16.92	/mo	1.42485	/mo	647
648					Direct Bury, Self-Support, 40ft	19.09	/mo	Direct Bury, Self-Support, 40ft	20.84	/mo	1.75486	/mo	648
649					Direct Bury, Stepped, 49ft	57.40	/mo	Direct Bury, Stepped, 49ft	62.68	/mo	5.27853	/mo	649
650					Direct Bury, Square, 4", 34ft	14.02	/mo	Direct Bury, Square, 4", 34ft	15.31	/mo	1.28880	/mo	650
651					Direct Bury, Square, 5", 20ft	13.31	/mo	Direct Bury, Square, 5", 20ft	14.53	/mo	1.22353	/mo	651
652					Direct Bury, Square, 30ft	13.87	/mo	Direct Bury, Square, 30ft	15.15	/mo	1.27501	/mo	652
653					Direct Bury, Square, 38ft	15.06	/mo	Direct Bury, Square, 38ft	16.44	/mo	1.38440	/mo	653
654					Decorative Transit 41-6	18.08	/mo	Decorative Transit 41-6	19.74	/mo	1.66202	/mo	654
655					Decorative Transit 47	22.52	/mo	Decorative Transit 47	24.59	/mo	2.07016	/mo	655
656					Direct Bury, Steel Dist Pole, 35ft	20.79	/mo	Direct Bury, Steel Dist Pole, 35ft	22.70	/mo	1.91113	/mo	656
657					D. Post Top, Dec Transit, 16ft	30.97	/mo	D. Post Top, Dec Transit, 16ft	33.82	/mo	2.84694	/mo	657
658					Post Top, Gray Steel/Fiberglass, 23ft	10.74	/mo	Post Top, Gray Steel/Fiberglass, 23ft	11.73	/mo	0.98728	/mo	658
659					Post Top, Black Steel, 23ft	11.84	/mo	Post Top, Black Steel, 23ft	12.93	/mo	1.08840	/mo	659
660					E. FROZEN, Wood Poles, 30ft	7.90	/mo	E. FROZEN, Wood Poles, 30ft	8.63	/mo	0.72621	/mo	660
661					FROZEN, Wood Poles, 35ft	7.90	/mo	FROZEN, Wood Poles, 35ft	8.63	/mo	0.72621	/mo	661
662					FROZEN, Wood Poles, 40ft	11.24	/mo	FROZEN, Wood Poles, 40ft	12.27	/mo	1.03324	/mo	662
663					ANCHOR BASE			ANCHOR BASE					663
664					Flush, 4ft	$ 8.75	/mo	Flush, 4ft	9.55	/mo	$ 0.80435	/mo	664
665					Flush, 6ft	10.44	/mo	Flush, 6ft	11.40	/mo	0.95970	/mo	665
666					Pedestal, 8ft	11.96	/mo	Pedestal, 8ft	13.06	/mo	1.09943	/mo	666
667					*Pedestal, 32' round steel pole, 4ft 6"*	8.29	/mo	Pedestal, 32' round steel pole, 4ft 6"	9.05	/mo	0.76206	/mo	667
668					OPTIONAL EQUIPMENT			OPTIONAL EQUIPMENT					668
669					1. 100' OH, UG if conduit by customer	$ 3.09	/mo	1. 100' OH, UG if conduit by customer	3.37	/mo	$ 0.28405	/mo	669
670					2. HPS not accessible by bucket	2.47	/mo	2. HPS not accessible by bucket	2.70	/mo	0.22706	/mo	670
671					3. MH not accessible by bucket	5.33	/mo	3. MH not accessible by bucket	5.82	/mo	0.48996	/mo	671
672					NON-STANDARD FACILITIES			NON-STANDARD FACILITIES					672
673					Service Charge	$ 2.96	/mo	Service Charge	3.23	/mo	$ 0.27210	/mo	673
674					All kWh	0.05604	/kWh	All kWh	0.06119	/kWh	0.00515	/kWh	674

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
675													675
676	E-51	Optional Electric	Basic	Sum & Win	Basic Service Charge	$ 0.276	/day						676
677		Service for Qualified			Generator Meter Charge	0.828	/day						677
678		Cogeneration and Small		Sum & Win	Reservation Charge per kW	2.488	/kW						678
679		Power Production			Initial Reservation Charge	24.88	/kW						679
680		Facilities over 100 KW											680
681			Standby	Summer	All On-Peak kWh	$ 0.05802	/kWh	RATE E-51 PROPOSE TO CANCEL;					681
682					All Off-Peak kWh	0.03342	/kWh	CUSTOMERS MOVE TO E-56.					682
683													683
684				Winter	All On-Peak kWh	$ 0.04471	/kWh						684
685					All Off-Peak kWh	0.03342	/kWh						685
686													686
687			Maintenance	Sum & Win	All kWh	$ 0.03342	/kWh						687
688													688
689	E-53	Electric Service for	Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU								689
690		Athletic Stadiums						NO CHANGE					690
691		and Sports Fields	Minimum	Sum & Win	No bills rendered when no usage								691
692													692
693	E-54	Seasonal Service	Rate	Sum & Win	Billed on Rate Schedule E-32 or Rate Schedule E-32TOU								693
694								NO CHANGE					694
695			Minimum	Sum & Win	"Floor" Annual Minimum	$ 603.49	/yr						695
696					Monthly Minimum	50.29	/mo						696
697													697
698	E-55	Electric Service for	Basic	Sum & Win	Basic Service Charge	$ 54.95	/day						698
699		Partial Requirements	Service		Generator Meter Charge	2.055	/day						699
700		Service of 3000 kW											700
701		or greater	Standby	Sum & Win	Res Charge per kW 95% abv	$ 4.21	/mo						701
702			Service		Res Charge per kW 90-94%	5.14	/mo						702
703					Res Charge per kW 80-89%	6.77	/mo						703
704				Summer	All On-Peak kWh	0.03040	/kWh						704
705				(Jun-Oct)	All Off-Peak kWh	0.01616	/kWh						705
706				Winter	All On-Peak kWh	0.02605	/kWh						706
707				(Nov-May)	All Off-Peak kWh	0.01033	/kWh						707
708													708
709			Maint.	Sum & Win	All On-Peak kWh	$ 0.02605	/kWh	RATE E-55 PROPOSE TO CANCEL;					709
710			Service		All Off-Peak kWh	0.01033	/kWh	CUSTOMERS MOVE TO E-56.					710
711													711
712			C.F. penalty	Sum & Win	C.F. less than 75%	$ 21.28	/kW						712
713					C.F. less than 75% @ 69kV	18.94	/kW						713
714					C.F. Transmission Level Reservation Chg	18.05	/kW						714
715													715
716		Above 69 kV	Standby	Sum & Win	Res Charge per kW 95% abv	$ 1.45	/mo						716
717			Service		Res Charge per kW 90-94%	2.30	/mo						717
718					Res Charge per kW 80-89%	4.11	/mo						718
719													719
720			C.F. penalty	Sum & Win	C.F. less than 75%	$ 18.94	/kW						720
721					C.F. less than 75% @ 69kV	18.11	/kW						721
722													722
723	E-56	Electric Service for	Basic										723
724		Partial Requirements	Service	Sum & Win	Basic Service Charge	per applicable rate		Basic Service Charge	per applicable rate				724
725		Service for CG				schedule			schedule				725
726		installations of 100kw											726
727			Supplemental	Sum & Win	All Supplemental Charges	per applicable rate		All Supplemental Charges	per applicable rate				727
728			Service			schedule			schedule				728
729													729
730			Back-Up	Sum & Win	Back-Up Service with E-32 On-Peak	0.0755	/kW-day	Back-Up Service with E-32 On-Peak	0.1005	/kW-day	0.02500	/kW-day	730
731			Service		Back-Up Service with E-32 Off-Peak	n/a		Back-Up Service with E-32 Off-Peak	n/a		-		731
732					Back-Up Service with E-34 On-Peak	0.4923	/kW-day	Back-Up Service with E-34 On-Peak	0.5968	/kW-day	0.10460	/kW-day	732
733					Back-Up Service with E-34 Off-Peak	n/a		Back-Up Service with E-34 Off-Peak	n/a		-		733
734													734
735			Maint.	Sum & Win	Scheduled Maintenance On-Peak	1/2 Back-up Charge		Scheduled Maintenance On-Peak	1/2 Back-up Charge		-		735
736			Service		Scheduled Maintenance Off-Peak	n/a		Scheduled Maintenance Off-Peak	n/a		-		736
737													737
738			Excess	Sum & Win	Secondary Service Excess Charge	$ 45.69	/kW	Secondary Service Excess Charge	$ 51.34	/kW	$ 5.45000	/kW	738
739					Primary Service Excess Charge	43.52	/kW	Primary Service Excess Charge	49.52	/kW	$ 6.00000	/kW	739
740					Transmission Service Excess Charge	31.73	/kW	Transmission Service Excess Charge	38.23	/kW	$ 6.50000	/kW	740
741													741

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
742													742
743	E-58	Street Lighting Service	Rate	Sum & Win	FIXTURES (Investment by Company)			FIXTURES (Investment by Company)					743
744					A. Acorn 9,500 HPS	$ 23.90	/mo	A. Acorn 9,500 HPS	27.18	/mo	$ 3.27566	/mo	744
745					Acorn 16,000 HPS	26.53	/mo	Acorn 16,000 HPS	30.17	/mo	3.63612	/mo	745
746					B. Architectural 9,500 HPS	13.58	/mo	B. Architectural 9,500 HPS	15.44	/mo	1.86123	/mo	746
747					Architectural 16,000 HPS	15.86	/mo	Architectural 16,000 HPS	18.03	/mo	2.17372	/mo	747
748					Architectural 30,000 HPS	18.82	/mo	Architectural 30,000 HPS	21.40	/mo	2.57941	/mo	748
749					Architectural 50,000 HPS	23.22	/mo	Architectural 50,000 HPS	26.40	/mo	3.18246	/mo	749
750					Architectural 14,000 MH	19.00	/mo	Architectural 14,000 MH	21.60	/mo	2.60408	/mo	750
751					Architectural 21,000 MH	21.57	/mo	Architectural 21,000 MH	24.53	/mo	2.95632	/mo	751
752					Architectural 36,000 MH	26.97	/mo	Architectural 36,000 MH	30.67	/mo	3.69643	/mo	752
753					Architectural 8,000 LPS	19.74	/mo	Architectural 8,000 LPS	22.45	/mo	2.70551	/mo	753
754					Architectural 13,500 LPS	23.26	/mo	Architectural 13,500 LPS	26.47	/mo	3.19069	/mo	754
755					Architectural 22,500 LPS	26.59	/mo	Architectural 22,500 LPS	30.23	/mo	3.64435	/mo	755
756					Architectural 33,000 LPS	31.99	/mo	Architectural 33,000 LPS	36.37	/mo	4.38445	/mo	756
757					C. Cobra/Roadway 5,800 HPS	7.71	/mo	C. Cobra/Roadway 5,800 HPS	8.77	/mo	1.05671	/mo	757
758					Cobra/Roadway 9,500 HPS	9.06	/mo	Cobra/Roadway 9,500 HPS	10.32	/mo	1.24448	/mo	758
759					Cobra/Roadway 16,000 HPS	11.37	/mo	Cobra/Roadway 16,000 HPS	12.93	/mo	1.55834	/mo	759
760					Cobra/Roadway 30,000 HPS	13.71	/mo	Cobra/Roadway 30,000 HPS	15.59	/mo	1.87905	/mo	760
761					Cobra/Roadway 50,000 HPS	18.60	/mo	Cobra/Roadway 50,000 HPS	21.15	/mo	2.54826	/mo	761
762					Cobra/Roadway 14,000 MH	13.22	/mo	Cobra/Roadway 14,000 MH	15.03	/mo	1.81189	/mo	762
763					Cobra/Roadway 21,000 MH	15.45	/mo	Cobra/Roadway 21,000 MH	17.57	/mo	2.11753	/mo	763
764					Cobra/Roadway 36,000 MH	20.34	/mo	Cobra/Roadway 36,000 MH	23.13	/mo	2.78774	/mo	764
765					Cobra/Roadway 8,000 FL	15.19	/mo	Cobra/Roadway 8,000 FL	17.27	/mo	2.08190	/mo	765
766					D. Decorative Transit 9,500 HPS	32.76	/mo	D. Decorative Transit 9,500 HPS	37.25	/mo	4.48996	/mo	766
767					Decorative Transit 16,000 HPS	32.57	/mo	Decorative Transit 16,000 HPS	37.03	/mo	4.46395	/mo	767
768					Decorative Transit 30,000 HPS	37.50	/mo	Decorative Transit 30,000 HPS	42.64	/mo	5.13964	/mo	768
769					E. Flood 30,000 HPS	18.20	/mo	E. Flood 30,000 HPS	20.69	/mo	2.49444	/mo	769
770					Flood 50,000 HPS	22.57	/mo	Flood 50,000 HPS	25.66	/mo	3.09338	/mo	770
771					Flood 21,000 MH	19.43	/mo	Flood 21,000 MH	22.09	/mo	2.66362	/mo	771
772					Flood 36,000 MH	23.69	/mo	Flood 36,000 MH	26.94	/mo	3.24686	/mo	772
773					F. Post Top gray 6,000 FL	16.37	/mo	F. Post Top gray 6,000 FL	18.61	/mo	2.24362	/mo	773
774					Post Top gray 9,500 HPS	9.36	/mo	Post Top gray 9,500 HPS	10.64	/mo	1.28285	/mo	774
775					Post Top black 9,500 HPS	10.78	/mo	Post Top black 9,500 HPS	12.26	/mo	1.47747	/mo	775
776					Post Top Transit 9,500 HPS	28.56	/mo	Post Top Transit 9,500 HPS	32.61	/mo	3.93080	/mo	776
777					G. FROZEN 4,000 INC	8.64	/mo	G. FROZEN 4,000 INC	9.82	/mo	1.18417	/mo	777
778					FROZEN 7,000 MV	11.19	/mo	FROZEN 7,000 MV	12.72	/mo	1.53367	/mo	778
779					FROZEN 11,000 MV	14.02	/mo	FROZEN 11,000 MV	15.94	/mo	1.92154	/mo	779
780					FROZEN 20,000 MV	22.01	/mo	FROZEN 20,000 MV	25.03	/mo	3.01662	/mo	780

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Staff Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (I) - (F)		Line No.
781													781
782	E-58	Street Lighting Service	Rate	Sum & Win	FIXTURES (Investment by Others)			FIXTURES (Investment by Others)					782
783	(cont)				A. Acorn 9,500 HPS	$ 8.14	/mo	A. Acorn 9,500 HPS	$ 9.26	/mo	$ 1.11564	/mo	783
784					Acorn 16,000 HPS	10.29	/mo	Acorn 16,000 HPS	11.70	/mo	1.41032	/mo	784
785					B. Architectural 9,500 HPS	6.48	/mo	B. Architectural 9,500 HPS	7.37	/mo	0.88813	/mo	785
786					Architectural 16,000 HPS	8.87	/mo	Architectural 16,000 HPS	9.86	/mo	1.18828	/mo	786
787					Architectural 30,000 HPS	11.13	/mo	Architectural 30,000 HPS	12.66	/mo	1.52544	/mo	787
788					Architectural 50,000 HPS	16.01	/mo	Architectural 50,000 HPS	18.20	/mo	2.19428	/mo	788
789					Architectural 14,000 MH	10.41	/mo	Architectural 14,000 MH	11.84	/mo	1.42676	/mo	789
790					Architectural 21,000 MH	12.84	/mo	Architectural 21,000 MH	14.60	/mo	1.75881	/mo	790
791					Architectural 36,000 MH	17.66	/mo	Architectural 36,000 MH	20.08	/mo	2.42043	/mo	791
792					Architectural 8,000 LPS	8.87	/mo	Architectural 8,000 LPS	9.86	/mo	1.18828	/mo	792
793					Architectural 13,500 LPS	10.46	/mo	B. Architectural 13,500 LPS	11.89	/mo	1.43362	/mo	793
794					Architectural 22,500 LPS	12.76	/mo	Architectural 22,500 LPS	14.51	/mo	1.74885	/mo	794
795					Architectural 33,000 LPS	15.03	/mo	Architectural 33,000 LPS	17.09	/mo	2.05997	/mo	795
796					C. Cobra/Roadway 5,800 HPS	4.56	/mo	C. Cobra/Roadway 5,800 HPS	5.18	/mo	0.62498	/mo	796
797					Cobra/Roadway 9,500 HPS	5.585	/mo	Cobra/Roadway 9,500 HPS	6.35	/mo	0.76545	/mo	797
798					Cobra/Roadway 16,000 HPS	7.79	/mo	Cobra/Roadway 16,000 HPS	8.86	/mo	1.06767	/mo	798
799					Cobra/Roadway 30,000 HPS	10.12	/mo	Cobra/Roadway 30,000 HPS	11.51	/mo	1.38702	/mo	799
800					Cobra/Roadway 50,000 HPS	14.46	/mo	Cobra/Roadway 50,000 HPS	16.44	/mo	1.98184	/mo	800
801					Cobra/Roadway 14,000 MH	9.01	/mo	Cobra/Roadway 14,000 MH	10.24	/mo	1.23488	/mo	801
802					Cobra/Roadway 21,000 MH	11.21	/mo	Cobra/Roadway 21,000 MH	12.75	/mo	1.53641	/mo	802
803					Cobra/Roadway 36,000 MH	15.57	/mo	Cobra/Roadway 36,000 MH	17.70	/mo	2.13398	/mo	803
804					Cobra/Roadway 8,000 FL	4.45	/mo	Cobra/Roadway 8,000 FL	5.06	/mo	0.60990	/mo	804
805					D. Decorative Transit 9,500 HPS	9.81	/mo	D. Decorative Transit 9,500 HPS	11.15	/mo	1.34453	/mo	805
806					Decorative Transit 16,000 HPS	10.96	/mo	Decorative Transit 16,000 HPS	12.46	/mo	1.50214	/mo	806
807					Decorative Transit 30,000 HPS	14.16	/mo	Decorative Transit 30,000 HPS	16.09	/mo	1.93936	/mo	807
808					E. Flood 30,000 HPS	11.31	/mo	E. Flood 30,000 HPS	12.86	/mo	1.55011	/mo	808
809					Flood 50,000 HPS	15.69	/mo	Flood 50,000 HPS	17.84	/mo	2.15042	/mo	809
810					Flood 21,000 MH	11.95	/mo	Flood 21,000 MH	13.59	/mo	1.63783	/mo	810
811					Flood 36,000 MH	16.21	/mo	Flood 36,000 MH	18.43	/mo	2.22169	/mo	811
812					F. Post Top gray 8,000 FL	4.62	/mo	F. Post Top gray 8,000 FL	5.25	/mo	0.63320	/mo	812
813					Post Top gray 9,500 HPS	5.87	/mo	Post Top gray 9,500 HPS	6.67	/mo	0.80452	/mo	813
814					Post Top black 9,500 HPS	6.08	/mo	Post Top black 9,500 HPS	6.91	/mo	0.83331	/mo	814
815					Post Top Transit 9,500 HPS	9.04	/mo	Post Top Transit 9,500 HPS	10.28	/mo	1.23900	/mo	815
816					G. FROZEN 4,000 INC	4.83	/mo	G. FROZEN 4,000 INC	5.49	/mo	0.66199	/mo	816
817					FROZEN 7,000 MV	6.42	/mo	FROZEN 7,000 MV	7.30	/mo	0.87991	/mo	817
818					FROZEN 11,000 MV	8.55	/mo	FROZEN 11,000 MV	9.72	/mo	1.17184	/mo	818
819					FROZEN 20,000 MV	12.47	/mo	FROZEN 20,000 MV	14.18	/mo	1.70910	/mo	819

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
820													820
821	E-58	Street Lighting Service	Rate	Sum & Win	POLES (Investment by Company)			POLES (Investment by Company)					821
822	(cont)				A. Anchor Flush, Round, 1X, 12ft	$ 10.75	/mo	A. Anchor Flush, Round, 1X, 12ft	12.22	/mo	$ 1.47335	/mo	822
823					Anchor Flush, Round, 1X, 22ft	12.10	/mo	Anchor Flush, Round, 1X, 22ft	13.76	/mo	1.65839	/mo	823
824					Anchor Flush, Round, 1X, 25ft	13.09	/mo	Anchor Flush, Round, 1X, 25ft	14.88	/mo	1.79408	/mo	824
825					Anchor Flush, Round, 1X, 30ft	15.04	/mo	Anchor Flush, Round, 1X, 30ft	17.10	/mo	2.06134	/mo	825
826					Anchor Flush, Round, 1X, 32ft	15.80	/mo	Anchor Flush, Round, 1X, 32ft	17.97	/mo	2.16550	/mo	826
827					Anchor Flush, Round, 2X, 12ft	11.46	/mo	Anchor Flush, Round, 2X, 12ft	13.03	/mo	1.57067	/mo	827
828					Anchor Flush, Round, 2X, 22ft	13.17	/mo	Anchor Flush, Round, 2X, 22ft	14.96	/mo	1.80504	/mo	828
829					Anchor Flush, Round, 2X, 25ft	13.73	/mo	Anchor Flush, Round, 2X, 25ft	15.61	/mo	1.88178	/mo	829
830					Anchor Flush, Round, 2X, 30ft	15.96	/mo	Anchor Flush, Round, 2X, 30ft	18.15	/mo	2.18743	/mo	830
831					Anchor Flush, Round, 2X, 32ft	17.03	/mo	Anchor Flush, Round, 2X, 32ft	19.36	/mo	2.33408	/mo	831
832					Anchor Flush, Square, 5", 13ft	12.32	/mo	Anchor Flush, Square, 5", 13ft	14.01	/mo	1.68854	/mo	832
833					Anchor Flush, Square, 5", 15ft	11.01	/mo	Anchor Flush, Square, 5", 15ft	12.52	/mo	1.50900	/mo	833
834					Anchor Flush, Square, 5", 23ft	13.06	/mo	Anchor Flush, Square, 5", 23ft	14.85	/mo	1.78996	/mo	834
835					Anchor Flush, Square, 5", 25ft	14.36	/mo	Anchor Flush, Square, 5", 25ft	16.33	/mo	1.96814	/mo	835
836					Anchor Flush, Square, 5", 28ft	15.94	/mo	Anchor Flush, Square, 5", 28ft	18.12	/mo	2.18469	/mo	836
837					Anchor Flush, Square, 5", 32ft	15.85	/mo	Anchor Flush, Square, 5", 32ft	18.02	/mo	2.17235	/mo	837
838					Anchor Flush, Concrete, 12ft	36.72	/mo	Anchor Flush, Concrete, 12ft	41.75	/mo	5.03273	/mo	838
839					Anchor Flush, Fiberglass, 12ft	31.10	/mo	Anchor Flush, Fiberglass, 12ft	35.36	/mo	4.26247	/mo	839
840					Anchor Flush, Dec Transit Pad, 4", 16ft	30.32	/mo	Anchor Flush, Dec Transit Pad, 4", 16ft	34.48	/mo	4.15557	/mo	840
841					Anchor Flush, Dec Transit, 6", 30ft	58.54	/mo	Anchor Flush, Dec Transit, 6", 30ft	66.56	/mo	8.02332	/mo	841
842					B. Anchor Pedstl, Round, 1X, 12ft	10.34	/mo	B. Anchor Pedstl, Round, 1X, 12ft	11.76	/mo	1.41717	/mo	842
843					Anchor Pedstl, Round, 1X, 22ft	11.69	/mo	Anchor Pedstl, Round, 1X, 22ft	13.29	/mo	1.60220	/mo	843
844					Anchor Pedstl, Round, 1X, 25ft	12.57	/mo	Anchor Pedstl, Round, 1X, 25ft	14.41	/mo	1.73651	/mo	844
845					Anchor Pedstl, Round, 1X, 30ft	14.64	/mo	Anchor Pedstl, Round, 1X, 30ft	16.65	/mo	2.00651	/mo	845
846					Anchor Pedstl, Round, 1X, 32ft	15.38	/mo	Anchor Pedstl, Round, 1X, 32ft	17.49	/mo	2.10794	/mo	846
847					Anchor Pedstl, Round, 2X, 12ft	11.05	/mo	Anchor Pedstl, Round, 2X, 12ft	12.56	/mo	1.51448	/mo	847
848					Anchor Pedstl, Round, 2X, 22ft	12.34	/mo	Anchor Pedstl, Round, 2X, 22ft	14.03	/mo	1.69128	/mo	848
849					Anchor Pedstl, Round, 2X, 25ft	13.32	/mo	Anchor Pedstl, Round, 2X, 25ft	15.15	/mo	1.82560	/mo	849
850					Anchor Pedstl, Round, 2X, 30ft	15.55	/mo	Anchor Pedstl, Round, 2X, 30ft	17.68	/mo	2.13124	/mo	850
851					Anchor Pedstl, Round, 2X, 32ft	16.61	/mo	Anchor Pedstl, Round, 2X, 32ft	18.89	/mo	2.27652	/mo	851
852					Anchor Pedstl, Round, 3 Bolt, 32ft	19.09	/mo	Anchor Pedstl, Round, 3 Bolt, 32ft	21.71	/mo	2.61642	/mo	852
853					Anchor Pedstl, Square, 5", 13ft	11.82	/mo	Anchor Pedstl, Square, 5", 13ft	13.55	/mo	1.63372	/mo	853
854					Anchor Pedstl, Square, 5", 15ft	12.19	/mo	Anchor Pedstl, Square, 5", 15ft	13.86	/mo	1.67073	/mo	854
855					Anchor Pedstl, Square, 5", 23ft	12.65	/mo	Anchor Pedstl, Square, 5", 23ft	14.38	/mo	1.73377	/mo	855
856					Anchor Pedstl, Square, 5", 25ft	13.95	/mo	Anchor Pedstl, Square, 5", 25ft	15.86	/mo	1.91195	/mo	856
857					Anchor Pedstl, Square, 5", 28ft	15.51	/mo	Anchor Pedstl, Square, 5", 28ft	17.64	/mo	2.12575	/mo	857
858					Anchor Pedstl, Square, 5", 32ft	16.10	/mo	Anchor Pedstl, Square, 5", 32ft	18.31	/mo	2.20662	/mo	858
859					C. Direct Bury, Round, 19ft	16.27	/mo	C. Direct Bury, Round, 19ft	18.50	/mo	2.22992	/mo	859
860					Direct Bury, Round, 30ft	12.70	/mo	Direct Bury, Round, 30ft	14.44	/mo	1.74062	/mo	860
861					Direct Bury, Round, 38ft	15.50	/mo	Direct Bury, Round, 38ft	17.62	/mo	2.12438	/mo	861
862					Direct Bury, Self-Support, 40ft	19.09	/mo	Direct Bury, Self-Support, 40ft	21.71	/mo	2.61642	/mo	862
863					Direct Bury, Stepped, 49ft	57.40	/mo	Direct Bury, Stepped, 49ft	65.27	/mo	7.86707	/mo	863
864					Direct Bury, Square, 4", 34ft	14.02	/mo	Direct Bury, Square, 4", 34ft	15.94	/mo	1.92154	/mo	864
865					Direct Bury, Square, 5", 20ft	13.31	/mo	Direct Bury, Square, 5", 20ft	15.13	/mo	1.82423	/mo	865
866					Direct Bury, Square, 30ft	13.87	/mo	Direct Bury, Square, 30ft	15.77	/mo	1.90096	/mo	866
867					Direct Bury, Square, 38ft	15.06	/mo	Direct Bury, Square, 38ft	17.12	/mo	2.06408	/mo	867
868					Decorative Transit 41- 6	18.08	/mo	Decorative Transit 41- 6	20.56	/mo	2.47799	/mo	868
869					Decorative Transit 47	22.52	/mo	Decorative Transit 47	25.61	/mo	3.06652	/mo	869
870					Direct Bury, Steel Dist Pole, 35ft	20.79	/mo	Direct Bury, Steel Dist Pole, 35ft	23.64	/mo	2.84942	/mo	870

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
871													871
872	E-58 (cont)	Street Lighting Service	Rate	Sum & Win	POLES (Investment by Company) (cont)			POLES (Investment by Company) (cont)					872
873					D. Post Top, Dec Transit, 16ft	$ 30.97	/mo	D. Post Top, Dec Transit, 16ft	35.21	/mo	$ 4.24486	/mo	873
874					Post Top, Gray Steel/Fiberglass, 23ft	10.74	/mo	Post Top, Gray Steel/Fiberglass, 23ft	12.21	/mo	1.47198	/mo	874
875					Post Top, Black Steel, 23ft	11.84	/mo	Post Top, Black Steel, 23ft	13.46	/mo	1.62276	/mo	875
876					E. Existing Distribution Pole	1.31	/mo	E. Existing Distribution Pole	1.49	/mo	0.17954	/mo	876
877					F. FROZEN, Wood Poles, 30ft	7.90	/mo	F. FROZEN, Wood Poles, 30ft	8.98	/mo	1.08275	/mo	877
878					FROZEN, Wood Poles, 35ft	7.90	/mo	FROZEN, Wood Poles, 35ft	8.98	/mo	1.08275	/mo	878
879					A. Anchor Flush, Round, 1X, 12ft	1.46	/mo	A. Anchor Flush, Round, 1X, 12ft	1.68	/mo	0.20284	/mo	879
880					Anchor Flush, Round, 1X, 22ft	1.66	/mo	Anchor Flush, Round, 1X, 22ft	1.89	/mo	0.22751	/mo	880
881					Anchor Flush, Round, 1X, 25ft	1.81	/mo	Anchor Flush, Round, 1X, 25ft	2.06	/mo	0.24807	/mo	881
882					Anchor Flush, Round, 1X, 30ft	2.07	/mo	Anchor Flush, Round, 1X, 30ft	2.35	/mo	0.28371	/mo	882
883					Anchor Flush, Round, 1X, 32ft	2.09	/mo	Anchor Flush, Round, 1X, 32ft	2.38	/mo	0.28645	/mo	883
884					Anchor Flush, Round, 2X, 12ft	1.58	/mo	Anchor Flush, Round, 2X, 12ft	1.80	/mo	0.21655	/mo	884
885					Anchor Flush, Round, 2X, 22ft	1.82	/mo	Anchor Flush, Round, 2X, 22ft	2.07	/mo	0.24944	/mo	885
886					Anchor Flush, Round, 2X, 25ft	1.99	/mo	Anchor Flush, Round, 2X, 25ft	2.15	/mo	0.25904	/mo	886
887					Anchor Flush, Round, 2X, 30ft	2.20	/mo	Anchor Flush, Round, 2X, 30ft	2.50	/mo	0.30153	/mo	887
888					Anchor Flush, Round, 2X, 32ft	2.35	/mo	Anchor Flush, Round, 2X, 32ft	2.67	/mo	0.32208	/mo	888
889					Anchor Flush, Square, 5", 13ft	1.70	/mo	Anchor Flush, Square, 5", 13ft	1.93	/mo	0.23300	/mo	889
890					Anchor Flush, Square, 5", 15ft	1.52	/mo	Anchor Flush, Square, 5", 15ft	1.73	/mo	0.20833	/mo	890
891					Anchor Flush, Square, 5", 23ft	1.79	/mo	Anchor Flush, Square, 5", 23ft	2.04	/mo	0.24533	/mo	891
892					Anchor Flush, Square, 5", 25ft	1.97	/mo	Anchor Flush, Square, 5", 25ft	2.24	/mo	0.27000	/mo	892
893					Anchor Flush, Square, 5", 28ft	2.19	/mo	Anchor Flush, Square, 5", 28ft	2.49	/mo	0.30015	/mo	893
894					Anchor Flush, Square, 5", 32ft	2.18	/mo	Anchor Flush, Square, 5", 32ft	2.48	/mo	0.29878	/mo	894
895					Anchor Flush, Concrete, 12ft	5.06	/mo	Anchor Flush, Concrete, 12ft	5.75	/mo	0.69351	/mo	895
896					Anchor Flush, Fiberglass, 12ft	4.25	/mo	Anchor Flush, Fiberglass, 12ft	4.87	/mo	0.58660	/mo	896
897					Anchor Flush, Dec Transit Ped, 4", 16ft	4.18	/mo	Anchor Flush, Dec Transit Ped, 4", 16ft	4.75	/mo	0.57290	/mo	897
898					Anchor Flush, Dec Transit, 6", 30ft	8.06	/mo	Anchor Flush, Dec Transit, 6", 30ft	9.16	/mo	1.10468	/mo	898
899					B. Anchor Pedstl, Round, 1X, 12ft	1.42	/mo	B. Anchor Pedstl, Round, 1X, 12ft	1.61	/mo	0.19462	/mo	899
900					Anchor Pedstl, Round, 1X, 22ft	1.61	/mo	Anchor Pedstl, Round, 1X, 22ft	1.83	/mo	0.22066	/mo	900
901					Anchor Pedstl, Round, 1X, 25ft	1.75	/mo	Anchor Pedstl, Round, 1X, 25ft	1.99	/mo	0.23985	/mo	901
902					Anchor Pedstl, Round, 1X, 30ft	2.02	/mo	Anchor Pedstl, Round, 1X, 30ft	2.30	/mo	0.27686	/mo	902
903					Anchor Pedstl, Round, 1X, 32ft	2.12	/mo	Anchor Pedstl, Round, 1X, 32ft	2.41	/mo	0.29056	/mo	903
904					Anchor Pedstl, Round, 2X, 12ft	1.52	/mo	Anchor Pedstl, Round, 2X, 12ft	1.73	/mo	0.20833	/mo	904
905					Anchor Pedstl, Round, 2X, 22ft	1.70	/mo	Anchor Pedstl, Round, 2X, 22ft	1.93	/mo	0.23300	/mo	905
906					Anchor Pedstl, Round, 2X, 25ft	1.83	/mo	Anchor Pedstl, Round, 2X, 25ft	2.08	/mo	0.25081	/mo	906
907					Anchor Pedstl, Round, 2X, 30ft	2.14	/mo	Anchor Pedstl, Round, 2X, 30ft	2.43	/mo	0.29330	/mo	907
908					Anchor Pedstl, Round, 2X, 32ft	2.29	/mo	Anchor Pedstl, Round, 2X, 32ft	2.60	/mo	0.31386	/mo	908
909					Anchor Pedstl, Round, 3 Bolt, 32ft	2.62	/mo	Anchor Pedstl, Round, 3 Bolt, 32ft	2.98	/mo	0.35909	/mo	909
910					Anchor Pedstl, Square, 5", 13ft	1.54	/mo	Anchor Pedstl, Square, 5", 13ft	1.86	/mo	0.22477	/mo	910
911					Anchor Pedstl, Square, 5", 15ft	1.67	/mo	Anchor Pedstl, Square, 5", 15ft	1.90	/mo	0.22889	/mo	911
912					Anchor Pedstl, Square, 5", 23ft	1.75	/mo	Anchor Pedstl, Square, 5", 23ft	1.99	/mo	0.23985	/mo	912
913					Anchor Pedstl, Square, 5", 25ft	1.93	/mo	Anchor Pedstl, Square, 5", 25ft	2.19	/mo	0.26452	/mo	913
914					Anchor Pedstl, Square, 5", 28ft	2.14	/mo	Anchor Pedstl, Square, 5", 28ft	2.43	/mo	0.29330	/mo	914
915					Anchor Pedstl, Square, 5", 32ft	2.21	/mo	Anchor Pedstl, Square, 5", 32ft	2.51	/mo	0.30290	/mo	915

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Rates	(G)	(H) Staff Proposed Rates Block	(I) Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
916													916
917	E-58	Street Lighting Service	Rate	Sum & Win	POLES (Investment by Others) (cont)			POLES (Investment by Others) (cont)					917
918	(cont)				C. Direct Bury, Round, 19ft	$ 2.24	/mo	C. Direct Bury, Round, 19ft	2.55	/mo	$ 0.30701	/mo	918
919					Direct Bury, Round, 30ft	2.35	/mo	Direct Bury, Round, 30ft	2.67	/mo	0.32208	/mo	919
920					Direct Bury, Round, 36ft	2.41	/mo	Direct Bury, Round, 36ft	2.74	/mo	0.33031	/mo	920
921					Direct Bury, Self-Support, 40ft	3.02	/mo	Direct Bury, Self-Support, 40ft	3.43	/mo	0.41391	/mo	921
922					Direct Bury, Stepped, 49ft	7.91	/mo	Direct Bury, Stepped, 49ft	8.99	/mo	1.08412	/mo	922
923					Direct Bury, Square, 4", 34ft	2.43	/mo	Direct Bury, Square, 4", 34ft	2.76	/mo	0.33305	/mo	923
924					Direct Bury, Square, 5", 20ft	2.20	/mo	Direct Bury, Square, 5", 20ft	2.50	/mo	0.30153	/mo	924
925					Direct Bury, Square, 30ft	2.29	/mo	Direct Bury, Square, 30ft	2.60	/mo	0.31385	/mo	925
926					Direct Bury, Square, 38ft	2.51	/mo	Direct Bury, Square, 38ft	2.87	/mo	0.35772	/mo	926
927					Decorative Transit 41- 6	2.66	/mo	Decorative Transit 41- 6	3.02	/mo	0.36457	/mo	927
928					Decorative Transit 47	3.31	/mo	Decorative Transit 47	3.76	/mo	0.45386	/mo	928
929					Direct Bury, Steel Dist Pole, 35ft	2.74	/mo	Direct Bury, Steel Dist Pole, 35ft	3.12	/mo	0.37554	/mo	929
930					D. Post Top, Dec Transit, 16ft	4.26	/mo	D. Post Top, Dec Transit, 16ft	4.84	/mo	0.58386	/mo	930
931					Post Top, Gray Steel/Fiberglass, 23ft	1.77	/mo	Post Top, Gray Steel/Fiberglass, 23ft	2.01	/mo	0.24259	/mo	931
932					Post Top, Black Steel, 23ft	1.95	/mo	Post Top, Black Steel, 23ft	2.22	/mo	0.26728	/mo	932
933					E. Existing Distribution Pole	-	/mo	E. Existing Distribution Pole	0.00	/mo	-	/mo	933
934					F. FROZEN, Wood Poles, 30ft	1.37	/mo	F. FROZEN, Wood Poles, 30ft	1.56	/mo	0.18777	/mo	934
935					FROZEN, Wood Poles, 35ft	1.31	/mo	FROZEN, Wood Poles, 35ft	1.49	/mo	0.17954	/mo	935
936					ANCHOR BASE (Investment by Company)			ANCHOR BASE (Investment by Company)					936
937					Flush, 4ft	$ 8.75	/mo	Flush, 4ft	9.95	/mo	$ 1.18825	/mo	937
938					Flush, 6ft	10.44	/mo	Flush, 6ft	11.87	/mo	1.43088	/mo	938
939					Pedestal, 8ft	11.96	/mo	Pedestal, 8ft	13.60	/mo	1.63920	/mo	939
940					Pedestal, 32' round steel pole, 4ft 6"	8.29	/mo	Pedestal, 32' round steel pole, 4ft 6"	9.43	/mo	1.13620	/mo	940
941					ANCHOR BASE (Investment by Others)			ANCHOR BASE (Investment by Others)					941
942					Flush, 4ft	$ 1.20	/mo	Flush, 4ft	1.36	/mo	$ 0.16447	/mo	942
943					Flush, 6ft	1.81	/mo	Flush, 6ft	2.06	/mo	0.24807	/mo	943
944					Pedestal, 8ft	2.08	/mo	Pedestal, 8ft	2.37	/mo	0.28508	/mo	944
945					Pedestal, 32' round steel pole, 4ft 6"	1.44	/mo	Pedestal, 32' round steel pole, 4ft 6"	1.64	/mo	0.19736	/mo	945
946					OPTIONAL EQUIPMENT			OPTIONAL EQUIPMENT					946
947					Per foot of cable under paving	$ 0.13880	/mo	Per foot of cable under paving	0.15782	/mo	$ 0.01902	/mo	947
948					Per foot of cable not under paving	0.04936	/mo	Per foot of cable not under paving	0.05613	/mo	0.00677	/mo	948
949													949
950													950
951	E-59	Energy Services for Government		Sum & Win	Service Charge	$ 2.46	/mo	Service Charge	2.75077	/mo	$ 0.29077	/mo	951
952		Owned Streetlighting Systems			Energy Charge	0.05385	/kWh	Energy Charge	0.06022	/kWh	0.00637	/kWh	952
953													953
954	E-67	Municipal Lighting	Rate	Sum & Win	All kWh	$ 0.04580	/kWh	All kWh	0.05124	/kWh	$ 0.00544	/kWh	954
955		Service -- City of Phoenix											955
956													956
957	E-114	Share the Light	Rate		Billed on Rate Schedule E-58			NO CHANGE					957
958													958
959	E-116	Share the Light	Rate		Billed on Rate Schedule E-58			NO CHANGE					959
960													960
961	E-145	Share the Light	Rate		Billed on Rate Schedule E-58			NO CHANGE					961

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
962													962
963	E-221	Water Pumping Service	Rate	Sum & Win	Basic Service Charge	$ 0.493	/day	Basic Service Charge	$ 0.606	/day	$ 0.11457	/day	963
964					All kW	1.560	/kW	All kW	1.862	/kW	0.20215	/kW	964
965					First 240 kWh	0.10311	/kWh	First 240 kWh	0.11567	/kWh	0.01256	/kWh	965
966					Next 275 kWh per kW	0.07010	/kWh	Next 275 kWh per kW	0.07864	/kWh	0.00854	/kWh	966
967					All additional kWh	0.05755	/kWh	All additional kWh	0.06456	/kWh	0.00701	/kWh	967
968													968
969		Time of Week Option		Sum & Win	Based on Measured kWh in Control Period:			Based on Measured kWh in Control Period:					969
970					2 kWh per kW or less	$ (0.00693)	/kWh	2 kWh per kW or less	$ (0.00777)	/kWh	$ (0.00084)	/kWh	970
971					Greater than 8 kWh/kW	0.00347	/kWh	Greater than 8 kWh/kW	0.00389	/kWh	0.00042	/kWh	971
972													972
973			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.493	/day	Minimum Basic Service Charge	$ 1.049	/day	$ 0.55577	/day	973
974					Minimum Demand Charge	1.66	/kW	Minimum Demand Charge	2.647	/kW	0.98740	/kW	974
975					Minimum Annual kW Charge	24.00	/kW	Minimum Annual kW Charge	24.00	/kW	-	/kW	975
976					Minimum Annual Lump Sum Charge	180.00	-	Minimum Annual Lump Sum Charge	180.00	-	-	-	976
977													977
978	E-221-ST	Water Pumping Service Time Of Use	Rate	Sum & Win	Basic Service Charge	$ 0.851	/day	Basic Service Charge	$ 1.049	/day	$ 0.19777	/day	978
979					All On-Peak kW	3.950	/kW	All On-Peak kW	4.431	/kW	0.48103	/kW	979
980					All Off-Peak kW	2.360	/kW	All Off-Peak kW	2.647	/kW	0.28740	/kW	980
981					All On-Peak kWh	0.08454	/kWh	All On-Peak kWh	0.09484	/kWh	0.01030	/kWh	981
982					All Off-Peak kWh	0.04547	/kWh	All Off-Peak kWh	0.05101	/kWh	0.00554	/kWh	982
983													983
984			Minimum	Sum & Win	Minimum Basic Service Charge	$ 0.851	/day	Minimum Basic Service Charge	$ 1.021	/day	$ 0.17000	/day	984
985					Minimum Demand Charge	2.360	/kW	Minimum Demand Charge	1.062	/kW	(1.29800)	/kW	985
986					Minimum Annual kW Charge	34.20	/kW	Minimum Annual kW Charge	34.20	/kW	-	/kW	986
987					Minimum Annual Lump Sum Charge	310.44	-	Minimum Annual Lump Sum Charge	310.44	-	-	/kW	987
988													988
989	E-249	Share the Light	Rate	Sum & Win	Billed on Rate Schedule E-58								989
990													990
991	CPP-GS	Critical Peak Pricing General Service	Rate	Sum & Win	PROPOSED NEW SCHEDULE			NO CHANGE					991
992								Critical Peak Price	$ 0.40000	/kWh	$ 0.40000	/kWh	992
993								Energy Discount E-32 M	$ (0.014892)	/kWh	$ (0.01489)	/kWh	993
994								Energy Discount E-32 L	(0.014438)	/kWh	(0.01444)	/kWh	994
995								Energy Discount E-32 TOU M	(0.014892)	/kWh	(0.01489)	/kWh	995
996								Energy Discount E-32 TOU L	(0.014438)	/kWh	(0.01444)	/kWh	996
997								Energy Discount E-34	(0.014350)	/kWh	(0.01435)	/kWh	997
998								Energy Discount E-35	(0.012470)	/kWh	(0.01247)	/kWh	998
999								Energy Discount E-221	(0.011755)	/kWh	(0.01176)	/kWh	999
1000													1000
1001	SC-S	Standard Contract - Solar	Rate	Sum & Win	NEW SCHEDULE PER A.C.C. DECISION NO. 70130			All kWh	Varies by Customer				1001
1002								All kW	Varies by Customer				1002
1003													1003
1004	EPR-2			Summer	Non-Firm On-Peak	$ 0.06486	/kWh	Non-Firm On-Peak	$ 0.06959		$ 0.00473	/kWh	1004
1005					Non-Firm Off-Peak	0.04531	/kWh	Non-Firm Off-Peak	0.05737		0.01206	/kWh	1005
1006					Firm On-Peak	0.07630	/kWh	Firm On-Peak	0.09802		0.02172	/kWh	1006
1007					Firm Off-Peak	0.05330	/kWh	Firm Off-Peak	0.06258		0.00928	/kWh	1007
1008													1008
1009				Winter	Non-Firm On-Peak	$ 0.06384	/kWh	Non-Firm On-Peak	$ 0.05578		$ (0.00806)	/kWh	1009
1010					Non-Firm Off-Peak	0.04905	/kWh	Non-Firm Off-Peak	0.05467		0.00562	/kWh	1010
1011					Firm On-Peak	0.07510	/kWh	Firm On-Peak	0.05578		(0.01932)	/kWh	1011
1012					Firm Off-Peak	0.05770	/kWh	Firm Off-Peak	0.05467		(0.00303)	/kWh	1012

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L)	Line No.
1013													1013
1014	EPR-2		12pm - 7pm	Summer	PROPOSED NEW ADDITION TO SCHEDULE			Non-Firm On-Peak	$ 0.07052		$ 0.07052	/kWh	1014
1015	(cont)		Rate					Non-Firm Off-Peak	0.05940		0.05940	/kWh	1015
1016								Firm On-Peak	0.11927		0.11927	/kWh	1016
1017								Firm Off-Peak	0.06364		0.06364	/kWh	1017
1018													1018
1019				Winter				Non-Firm On-Peak	$ 0.05245		$ 0.05245	/kWh	1019
1020								Non-Firm Off-Peak	0.05577		0.05577	/kWh	1020
1021								Firm On-Peak	0.05245		0.05245	/kWh	1021
1022								Firm Off-Peak	0.05577		0.05577	/kWh	1022
1023													1023
1024			11am - 9pm	Summer				Non-Firm On-Peak	$ 0.07057		$ 0.07057	/kWh	1024
1025			Rate					Non-Firm Off-Peak	0.05798		0.05798	/kWh	1025
1026								Firm On-Peak	0.10489		0.10489	/kWh	1026
1027								Firm Off-Peak	0.06275		0.06275	/kWh	1027
1028													1028
1029				Winter				Non-Firm On-Peak	$ 0.05518		$ 0.05518	/kWh	1029
1030								Non-Firm Off-Peak	0.05502		0.05502	/kWh	1030
1031								Firm On-Peak	0.05518		0.05518	/kWh	1031
1032								Firm Off-Peak	0.05502		0.05502	/kWh	1032
1033													1033
1034	EPR-5	Net Metering Rate		Sum & Win	Energy Credit for Excess Generation	Credited Rates Per Applicable Rate Schedule		Energy Credit for Excess Generation	Credited Rates Per Applicable Rate Schedule				1034
1035		Renewable Resource Facilities											1035
1036		of 100 kW or Less for Partial											1036
1037													1037
1038	Solar-2	Individual Solar	Initial Fee	Sum & Win	Up to $100,000	5% one time		NO CHANGE					1038
1039		Electric Service			More than $100,000	10% one time							1039
1040													1040
1041			Rate	Sum & Win	Service Fee:								1041
1042					Battery: None, sys size up to 2.5 kW	$ 5.00 /mo							1042
1043					Battery: None, sys size over 2.5 kW	5.00 /mo							1043
1044					Battery: Sealed, sys size up to 2.5 kW	45.00 /mo							1044
1045					Battery: Sealed, sys size over 2.5 kW	65.00 /mo							1045
1046					Battery: Flooded, sys size up to 2.5 kW	65.00 /mo							1046
1047					Battery: Flooded, sys size over 2.5 kW	85.00 /mo							1047
1048													1048
1049					Component Fee:								1049
1050					Long	1.41% /mo							1050
1051					Medium	1.83% /mo							1051
1052					Short	2.75% /mo							1052
1053													1053
1054	Solar-3	Solar Power Pilot Program	Rate	Sum & Win	Solar Power Premium	$ 0.16600 /kWh		NO CHANGE					1054
1055													1055
1056	SP-1	Solar Partners	Rate	Sum & Win	Residential/Business 15 kWh per month	$ 2.64 /mo		NO CHANGE					1056
1057													1057
1058	DSMAC-1[1]	Demand Side Management	Adjustment	Sum & Win	all kWh	$ - /kWh		NO CHANGE					1058
1059		Adjustment Charge			all kW	- /kW							1059

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES

COMPARISON OF PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2007

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block	(F) Present Rates Rates	(G)	(H) Staff Proposed Rates Block	(I) Staff Proposed Rates Rates	(J)	(K) Change (I) - (F)	(L) Line No.
1060												1060
1061	CRCC-1[1]	Competition Rules	Adjustment	Sum & Win	All kWh	$ 0.000338	/kWh	NO CHANGE				1061
1062		Compliance Charge										1062
1063												1063
1064	RCDAC-1[1]	Returning Customer Direct	Adjustment	Sum & Win	Customers over 3mW	varies by customer		NO CHANGE				1064
1065		Access Charge										1065
1066												1066
1067	PSA-1[1,2]	Power Supply	Adjustment	Sum & Win	PSA Adjustor	$ 0.003987	/kWh	NO CHANGE				1067
1068		Adjustment			PSA Historical	0.001048	/kWh					1068
1069					PSA Forward	0.002952	/kWh					1069
1070					PSA Transition	-	/kWh					1070
1071					PSA Surcharge	0.001176	/kWh					1071
1072												1072
1073	RES[1]	Renewable Energy Standard	Adjustment	Sum & Win	All kWh	$ 0.003288	/kWh	NO CHANGE.				1073
1074					Cap for all Residential Services	1.32	/service	ADJUSTOR SCHEDULE RES REPLACED				1074
1075					Cap for General Services under 3MW	46.84	/service	ADJUSTOR SCHEDULE EPS-1 PER DECISION NO. 70313				1075
1076					Cap for General Services 3MW and above	146.53	/service					1076
1077												1077
1078	ES[1]	Environmental	Adjustment	Sum & Win	All kWh	$ 0.00016	/kWh	NO CHANGE				1078
1079		Improvement Surcharge										1079
1080												1080
1081	TCA-1[1,3]	Transmission	Adjustment	Sum & Win	NEW ADJUSTMENT SCHEDULE PER A.C.C. DECISION NO. 69663			Reflected the unbundled transmission charges approved by				1081
1082		Cost						A.C.C. and FERC approved OATT per the TCA PDA.				1082
1083												1083
1084												1084
1085												1085
1086												1086
1087	GPS-1[1]	Green Power Block Schedule	Adjustment	Sum & Win	100 kWh Block	$ 1.00000	/kWh Block	NO CHANGE				1087
1088												1088
1089	GPS-2[1]	Green Power Percent Schedule	Adjustment	Sum & Win	100.0% total monthly kWh	$ 0.01000	/kWh	NO CHANGE				1089
1090					50.0% total monthly kWh	0.00500	/kWh					1090
1091					35.0% total monthly kWh	0.00350	/kWh					1091
1092					10.0% total monthly kWh	0.00100	/kWh					1092
1093												1093
1094	SDR	Self Directed Renewable Resources	Adjustment	Sum & Win	Varies per customer			NO CHANGE				1094
1095												1095
1096												1096

1097 [1] These adjustor schedules may be modified outside of a rate case in accordance with the adjustor schedules's Plan of Administration. These schedules do not impact any of the proof of revenue's.

1098 [2] Update to adjustment schedule PSA-1 approved by A.C.C. Decision No. 69663 per the PSA PDA.

1099 [3] Unbundled transmission cost removed from proposed base rates.

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Proposed rates are shown on a bundled basis. See Tariff Sheets for unbundled components.
2) Present rates effective 7/01/2007.

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
E-12 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	24.24	27.68	-	27.68	3.44	14.2%
250	28.41	32.26	-	32.26	3.85	13.6%
300	32.57	36.84	-	36.84	4.27	13.1%
350	36.73	41.42	-	41.42	4.69	12.8%
400	40.90	46.00	-	46.00	5.10	12.5%
450	45.06	50.58	-	50.58	5.52	12.3%
500	49.23	55.16	-	55.16	5.93	12.0%
550	53.39	59.74	-	59.74	6.35	11.9%
600	57.55	64.32	-	64.32	6.77	11.8%
650	61.72	68.90	-	68.90	7.18	11.6%
700	65.88	73.49	-	73.49	7.61	11.6%
750	70.04	78.07	-	78.07	8.03	11.5%
800	74.21	82.65	-	82.65	8.44	11.4%
850	78.37	87.23	-	87.23	8.86	11.3%
900	82.53	91.81	-	91.81	9.28	11.2%
950	86.70	96.39	-	96.39	9.69	11.2%
1,000	90.86	100.97	-	100.97	10.11	11.1%
1,100	99.19	110.13	-	110.13	10.94	11.0%
1,200	107.51	119.29	-	119.29	11.78	11.0%
1,300	115.84	128.46	-	128.46	12.62	10.9%
1,400	124.17	137.62	-	137.62	13.45	10.8%
1,500	132.50	146.78	-	146.78	14.28	10.8%
1,600	140.82	155.94	-	155.94	15.12	10.7%
1,700	149.15	165.10	-	165.10	15.95	10.7%
1,800	157.48	174.26	-	174.26	16.78	10.7%
1,900	165.80	183.42	-	183.42	17.62	10.6%
2,000	174.13	192.59	-	192.59	18.46	10.6%
2,200	190.78	210.91	-	210.91	20.13	10.6%
2,400	207.44	229.23	-	229.23	21.79	10.5%
2,600	224.09	247.56	-	247.56	23.47	10.5%
2,800	240.75	265.88	-	265.88	25.13	10.4%
3,000	257.40	284.20	-	284.20	26.80	10.4%
4,000	340.67	375.82	-	375.82	35.15	10.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
E-12 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	24.73	28.21	-	28.21	3.48	14.1%
250	29.02	32.93	-	32.93	3.91	13.5%
300	33.30	37.64	-	37.64	4.34	13.0%
350	37.59	42.36	-	42.36	4.77	12.7%
400	41.87	47.07	-	47.07	5.20	12.4%
450	47.96	53.77	-	53.77	5.81	12.1%
500	54.05	60.47	-	60.47	6.42	11.9%
550	60.13	67.16	-	67.16	7.03	11.7%
600	66.22	73.86	-	73.86	7.64	11.5%
650	72.31	80.56	-	80.56	8.25	11.4%
700	78.40	87.26	-	87.26	8.86	11.3%
750	84.48	93.95	-	93.95	9.47	11.2%
800	90.57	100.65	-	100.65	10.08	11.1%
850	97.78	108.59	-	108.59	10.81	11.1%
900	105.00	116.52	-	116.52	11.52	11.0%
950	112.21	124.46	-	124.46	12.25	10.9%
1,000	119.42	132.40	-	132.40	12.98	10.9%
1,100	133.85	148.27	-	148.27	14.42	10.8%
1,200	148.28	164.14	-	164.14	15.86	10.7%
1,300	162.71	180.02	-	180.02	17.31	10.6%
1,400	177.13	195.89	-	195.89	18.76	10.6%
1,500	191.56	211.76	-	211.76	20.20	10.5%
1,600	205.99	227.64	-	227.64	21.65	10.5%
1,700	220.41	243.51	-	243.51	23.10	10.5%
1,800	234.84	259.38	-	259.38	24.54	10.4%
1,900	249.27	275.25	-	275.25	25.98	10.4%
2,000	263.69	291.13	-	291.13	27.44	10.4%
2,200	292.55	322.87	-	322.87	30.32	10.4%
2,400	321.40	354.62	-	354.62	33.22	10.3%
2,600	350.26	386.37	-	386.37	36.11	10.3%
2,800	379.11	418.11	-	418.11	39.00	10.3%
3,000	407.96	449.86	-	449.86	41.90	10.3%
4,000	552.23	619.73	-	619.73	67.50	12.2%
5,000	696.50	789.60	-	789.60	93.10	13.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
E-12/E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.55	14.55	-	14.55	-	0.0%
250	17.04	17.04	-	17.04	-	0.0%
300	19.54	19.54	-	19.54	-	0.0%
350	22.04	22.04	-	22.04	-	0.0%
400	24.54	24.54	-	24.54	-	0.0%
450	33.35	33.35	-	33.35	-	0.0%
500	36.43	36.43	-	36.43	-	0.0%
550	39.51	39.51	-	39.51	-	0.0%
600	42.59	42.59	-	42.59	-	0.0%
650	45.67	45.67	-	45.67	-	0.0%
700	48.75	48.75	-	48.75	-	0.0%
750	51.83	51.83	-	51.83	-	0.0%
800	54.91	54.91	-	54.91	-	0.0%
850	67.40	67.40	-	67.40	-	0.0%
900	70.98	70.98	-	70.98	-	0.0%
950	74.56	74.56	-	74.56	-	0.0%
1,000	78.14	78.14	-	78.14	-	0.0%
1,100	85.30	85.30	-	85.30	-	0.0%
1,200	92.46	92.46	-	92.46	-	0.0%
1,300	102.84	102.84	-	102.84	-	0.0%
1,400	111.17	111.17	-	111.17	-	0.0%
1,500	119.50	119.50	-	119.50	-	0.0%
1,600	127.82	127.82	-	127.82	-	0.0%
1,700	136.15	136.15	-	136.15	-	0.0%
1,800	144.48	144.48	-	144.48	-	0.0%
1,900	152.80	152.80	-	152.80	-	0.0%
2,000	161.13	161.13	-	161.13	-	0.0%
2,200	177.78	177.78	-	177.78	-	0.0%
2,400	194.44	194.44	-	194.44	-	0.0%
2,600	211.09	211.09	-	211.09	-	0.0%
2,800	227.75	227.75	-	227.75	-	0.0%
3,000	244.40	244.40	-	244.40	-	0.0%
4,000	327.67	327.67	-	327.67	-	0.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
E-12/E-3 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.84	14.84	-	14.84	-	0.0%
250	17.41	17.41	-	17.41	-	0.0%
300	19.98	19.98	-	19.98	-	0.0%
350	22.55	22.55	-	22.55	-	0.0%
400	25.12	25.12	-	25.12	-	0.0%
450	35.49	35.49	-	35.49	-	0.0%
500	39.99	39.99	-	39.99	-	0.0%
550	44.50	44.50	-	44.50	-	0.0%
600	49.00	49.00	-	49.00	-	0.0%
650	53.51	53.51	-	53.51	-	0.0%
700	58.01	58.01	-	58.01	-	0.0%
750	62.52	62.52	-	62.52	-	0.0%
800	67.02	67.02	-	67.02	-	0.0%
850	84.09	84.09	-	84.09	-	0.0%
900	90.30	90.30	-	90.30	-	0.0%
950	96.50	96.50	-	96.50	-	0.0%
1,000	102.70	102.70	-	102.70	-	0.0%
1,100	115.11	115.11	-	115.11	-	0.0%
1,200	127.52	127.52	-	127.52	-	0.0%
1,300	149.71	149.71	-	149.71	-	0.0%
1,400	164.13	164.13	-	164.13	-	0.0%
1,500	178.56	178.56	-	178.56	-	0.0%
1,600	192.99	192.99	-	192.99	-	0.0%
1,700	207.41	207.41	-	207.41	-	0.0%
1,800	221.84	221.84	-	221.84	-	0.0%
1,900	236.27	236.27	-	236.27	-	0.0%
2,000	250.69	250.69	-	250.69	-	0.0%
2,200	279.55	279.55	-	279.55	-	0.0%
2,400	308.40	308.40	-	308.40	-	0.0%
2,600	337.26	337.26	-	337.26	-	0.0%
2,800	366.11	366.11	-	366.11	-	0.0%
3,000	394.96	394.96	-	394.96	-	0.0%
4,000	539.23	539.23	-	539.23	-	0.0%
5,000	683.50	683.50	-	683.50	-	0.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
E-12/E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.55	14.55	-	14.55	-	0.0%
250	17.04	17.04	-	17.04	-	0.0%
300	19.54	19.54	-	19.54	-	0.0%
350	22.04	22.04	-	22.04	-	0.0%
400	24.54	24.54	-	24.54	-	0.0%
450	27.04	27.04	-	27.04	-	0.0%
500	29.54	29.54	-	29.54	-	0.0%
550	32.03	32.03	-	32.03	-	0.0%
600	34.53	34.53	-	34.53	-	0.0%
650	37.03	37.03	-	37.03	-	0.0%
700	39.53	39.53	-	39.53	-	0.0%
750	42.03	42.03	-	42.03	-	0.0%
800	44.52	44.52	-	44.52	-	0.0%
850	57.99	57.99	-	57.99	-	0.0%
900	61.07	61.07	-	61.07	-	0.0%
950	64.16	64.16	-	64.16	-	0.0%
1,000	67.24	67.24	-	67.24	-	0.0%
1,100	73.40	73.40	-	73.40	-	0.0%
1,200	79.56	79.56	-	79.56	-	0.0%
1,300	85.72	85.72	-	85.72	-	0.0%
1,400	91.88	91.88	-	91.88	-	0.0%
1,500	113.95	113.95	-	113.95	-	0.0%
1,600	121.11	121.11	-	121.11	-	0.0%
1,700	128.27	128.27	-	128.27	-	0.0%
1,800	135.43	135.43	-	135.43	-	0.0%
1,900	142.59	142.59	-	142.59	-	0.0%
2,000	149.75	149.75	-	149.75	-	0.0%
2,200	164.78	164.78	-	164.78	-	0.0%
2,400	181.44	181.44	-	181.44	-	0.0%
2,600	198.09	198.09	-	198.09	-	0.0%
2,800	214.75	214.75	-	214.75	-	0.0%
3,000	231.40	231.40	-	231.40	-	0.0%
4,000	314.67	314.67	-	314.67	-	0.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
E-12/E-4 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	14.84	14.84	-	14.84	-	0.0%
250	17.41	17.41	-	17.41	-	0.0%
300	19.98	19.98	-	19.98	-	0.0%
350	22.55	22.55	-	22.55	-	0.0%
400	25.12	25.12	-	25.12	-	0.0%
450	28.77	28.77	-	28.77	-	0.0%
500	32.43	32.43	-	32.43	-	0.0%
550	36.08	36.08	-	36.08	-	0.0%
600	39.73	39.73	-	39.73	-	0.0%
650	43.38	43.38	-	43.38	-	0.0%
700	47.04	47.04	-	47.04	-	0.0%
750	50.69	50.69	-	50.69	-	0.0%
800	54.34	54.34	-	54.34	-	0.0%
850	72.36	72.36	-	72.36	-	0.0%
900	77.70	77.70	-	77.70	-	0.0%
950	83.04	83.04	-	83.04	-	0.0%
1,000	88.37	88.37	-	88.37	-	0.0%
1,100	99.05	99.05	-	99.05	-	0.0%
1,200	109.73	109.73	-	109.73	-	0.0%
1,300	120.40	120.40	-	120.40	-	0.0%
1,400	131.08	131.08	-	131.08	-	0.0%
1,500	164.74	164.74	-	164.74	-	0.0%
1,600	177.15	177.15	-	177.15	-	0.0%
1,700	189.56	189.56	-	189.56	-	0.0%
1,800	201.96	201.96	-	201.96	-	0.0%
1,900	214.37	214.37	-	214.37	-	0.0%
2,000	226.78	226.78	-	226.78	-	0.0%
2,200	266.55	266.55	-	266.55	-	0.0%
2,400	295.40	295.40	-	295.40	-	0.0%
2,600	324.26	324.26	-	324.26	-	0.0%
2,800	353.11	353.11	-	353.11	-	0.0%
3,000	381.96	381.96	-	381.96	-	0.0%
4,000	526.23	526.23	-	526.23	-	0.0%
5,000	670.50	670.50	-	670.50	-	0.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-1 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	29.87	32.26	-	32.26	2.39	8.0%
250	33.64	36.50	-	36.50	2.86	8.5%
300	37.41	40.75	-	40.75	3.34	8.9%
350	41.18	44.99	-	44.99	3.81	9.3%
400	44.94	49.24	-	49.24	4.30	9.6%
450	48.71	53.49	-	53.49	4.78	9.8%
500	52.48	57.73	-	57.73	5.25	10.0%
550	56.25	61.98	-	61.98	5.73	10.2%
600	60.02	66.23	-	66.23	6.21	10.3%
650	63.79	70.47	-	70.47	6.68	10.5%
700	67.56	74.72	-	74.72	7.16	10.6%
750	71.33	78.97	-	78.97	7.64	10.7%
800	75.10	83.21	-	83.21	8.11	10.8%
850	78.87	87.46	-	87.46	8.59	10.9%
900	82.64	91.70	-	91.70	9.06	11.0%
950	86.41	95.95	-	95.95	9.54	11.0%
1,000	90.18	100.20	-	100.20	10.02	11.1%
1,100	97.71	108.69	-	108.69	10.98	11.2%
1,200	105.25	117.18	-	117.18	11.93	11.3%
1,300	112.79	125.68	-	125.68	12.89	11.4%
1,400	120.33	134.17	-	134.17	13.84	11.5%
1,500	127.87	142.66	-	142.66	14.79	11.6%
1,600	135.41	151.15	-	151.15	15.74	11.6%
1,700	142.95	159.65	-	159.65	16.70	11.7%
1,800	150.48	168.14	-	168.14	17.66	11.7%
1,900	158.02	176.63	-	176.63	18.61	11.8%
2,000	165.56	185.12	-	185.12	19.56	11.8%
2,200	180.64	202.11	-	202.11	21.47	11.9%
2,400	195.72	219.10	-	219.10	23.38	11.9%
2,600	210.79	236.08	-	236.08	25.29	12.0%
2,800	225.87	253.07	-	253.07	27.20	12.0%
3,000	240.95	270.05	-	270.05	29.10	12.1%

ET-1 Winter Average Energy On-Peak: 33%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-1 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	33.78	36.67	-	36.67	2.89	8.6%
250	38.53	42.02	-	42.02	3.49	9.1%
300	43.28	47.37	-	47.37	4.09	9.5%
350	48.03	52.72	-	52.72	4.69	9.8%
400	52.78	58.07	-	58.07	5.29	10.0%
450	57.53	63.42	-	63.42	5.89	10.2%
500	62.28	68.77	-	68.77	6.49	10.4%
550	67.02	74.11	-	74.11	7.09	10.6%
600	71.77	79.46	-	79.46	7.69	10.7%
650	76.52	84.81	-	84.81	8.29	10.8%
700	81.27	90.16	-	90.16	8.89	10.9%
750	86.02	95.51	-	95.51	9.49	11.0%
800	90.77	100.86	-	100.86	10.09	11.1%
850	95.51	106.21	-	106.21	10.70	11.2%
900	100.26	111.56	-	111.56	11.30	11.3%
950	105.01	116.91	-	116.91	11.90	11.3%
1,000	109.76	122.26	-	122.26	12.50	11.4%
1,100	119.26	132.96	-	132.96	13.70	11.5%
1,200	128.75	143.66	-	143.66	14.91	11.6%
1,300	138.25	154.36	-	154.36	16.11	11.7%
1,400	147.75	165.06	-	165.06	17.31	11.7%
1,500	157.25	175.76	-	175.76	18.51	11.8%
1,600	166.74	186.45	-	186.45	19.71	11.8%
1,700	176.24	197.15	-	197.15	20.91	11.9%
1,800	185.74	207.85	-	207.85	22.11	11.9%
1,900	195.23	218.55	-	218.55	23.32	11.9%
2,000	204.73	229.25	-	229.25	24.52	12.0%
2,200	223.72	250.65	-	250.65	26.93	12.0%
2,400	242.72	272.05	-	272.05	29.33	12.1%
2,600	261.71	293.44	-	293.44	31.73	12.1%
2,800	280.71	314.84	-	314.84	34.13	12.2%
3,000	299.70	336.24	-	336.24	36.54	12.2%

ET-1 Summer Average Energy On-Peak: 41%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-1/E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.92	17.92	-	17.92	-	0.0%
250	20.18	20.18	-	20.18	-	0.0%
300	22.44	22.44	-	22.44	-	0.0%
350	24.71	24.71	-	24.71	-	0.0%
400	26.97	26.97	-	26.97	-	0.0%
450	36.05	36.05	-	36.05	-	0.0%
500	38.84	38.84	-	38.84	-	0.0%
550	41.63	41.63	-	41.63	-	0.0%
600	44.42	44.42	-	44.42	-	0.0%
650	47.21	47.21	-	47.21	-	0.0%
700	49.99	49.99	-	49.99	-	0.0%
750	52.78	52.78	-	52.78	-	0.0%
800	55.57	55.57	-	55.57	-	0.0%
850	67.83	67.83	-	67.83	-	0.0%
900	71.07	71.07	-	71.07	-	0.0%
950	74.31	74.31	-	74.31	-	0.0%
1,000	77.55	77.55	-	77.55	-	0.0%
1,100	84.03	84.03	-	84.03	-	0.0%
1,200	90.52	90.52	-	90.52	-	0.0%
1,300	99.79	99.79	-	99.79	-	0.0%
1,400	107.33	107.33	-	107.33	-	0.0%
1,500	114.87	114.87	-	114.87	-	0.0%
1,600	122.41	122.41	-	122.41	-	0.0%
1,700	129.95	129.95	-	129.95	-	0.0%
1,800	137.48	137.48	-	137.48	-	0.0%
1,900	145.02	145.02	-	145.02	-	0.0%
2,000	152.56	152.56	-	152.56	-	0.0%
2,200	167.64	167.64	-	167.64	-	0.0%
2,400	182.72	182.72	-	182.72	-	0.0%
2,600	197.79	197.79	-	197.79	-	0.0%
2,800	212.87	212.87	-	212.87	-	0.0%
3,000	227.95	227.95	-	227.95	-	0.0%

ET-1 Winter Average Energy On-Peak: 33%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-1/E-3 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.27	20.27	-	20.27	-	0.0%
250	23.12	23.12	-	23.12	-	0.0%
300	25.97	25.97	-	25.97	-	0.0%
350	28.82	28.82	-	28.82	-	0.0%
400	31.67	31.67	-	31.67	-	0.0%
450	42.57	42.57	-	42.57	-	0.0%
500	46.08	46.08	-	46.08	-	0.0%
550	49.60	49.60	-	49.60	-	0.0%
600	53.11	53.11	-	53.11	-	0.0%
650	56.63	56.63	-	56.63	-	0.0%
700	60.14	60.14	-	60.14	-	0.0%
750	63.65	63.65	-	63.65	-	0.0%
800	67.17	67.17	-	67.17	-	0.0%
850	82.14	82.14	-	82.14	-	0.0%
900	86.23	86.23	-	86.23	-	0.0%
950	90.31	90.31	-	90.31	-	0.0%
1,000	94.39	94.39	-	94.39	-	0.0%
1,100	102.56	102.56	-	102.56	-	0.0%
1,200	110.73	110.73	-	110.73	-	0.0%
1,300	125.25	125.25	-	125.25	-	0.0%
1,400	134.75	134.75	-	134.75	-	0.0%
1,500	144.25	144.25	-	144.25	-	0.0%
1,600	153.74	153.74	-	153.74	-	0.0%
1,700	163.24	163.24	-	163.24	-	0.0%
1,800	172.74	172.74	-	172.74	-	0.0%
1,900	182.23	182.23	-	182.23	-	0.0%
2,000	191.73	191.73	-	191.73	-	0.0%
2,200	210.72	210.72	-	210.72	-	0.0%
2,400	229.72	229.72	-	229.72	-	0.0%
2,600	248.71	248.71	-	248.71	-	0.0%
2,800	267.71	267.71	-	267.71	-	0.0%
3,000	286.70	286.70	-	286.70	-	0.0%

ET-1 Summer Average Energy On-Peak: 41%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-1/E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.92	17.92	-	17.92	-	0.0%
250	20.18	20.18	-	20.18	-	0.0%
300	22.44	22.44	-	22.44	-	0.0%
350	24.71	24.71	-	24.71	-	0.0%
400	26.97	26.97	-	26.97	-	0.0%
450	29.23	29.23	-	29.23	-	0.0%
500	31.49	31.49	-	31.49	-	0.0%
550	33.75	33.75	-	33.75	-	0.0%
600	36.01	36.01	-	36.01	-	0.0%
650	38.27	38.27	-	38.27	-	0.0%
700	40.54	40.54	-	40.54	-	0.0%
750	42.80	42.80	-	42.80	-	0.0%
800	45.06	45.06	-	45.06	-	0.0%
850	58.36	58.36	-	58.36	-	0.0%
900	61.15	61.15	-	61.15	-	0.0%
950	63.94	63.94	-	63.94	-	0.0%
1,000	66.73	66.73	-	66.73	-	0.0%
1,100	72.31	72.31	-	72.31	-	0.0%
1,200	77.89	77.89	-	77.89	-	0.0%
1,300	83.47	83.47	-	83.47	-	0.0%
1,400	89.04	89.04	-	89.04	-	0.0%
1,500	109.97	109.97	-	109.97	-	0.0%
1,600	116.45	116.45	-	116.45	-	0.0%
1,700	122.93	122.93	-	122.93	-	0.0%
1,800	129.42	129.42	-	129.42	-	0.0%
1,900	135.90	135.90	-	135.90	-	0.0%
2,000	142.38	142.38	-	142.38	-	0.0%
2,200	154.64	154.64	-	154.64	-	0.0%
2,400	169.72	169.72	-	169.72	-	0.0%
2,600	184.79	184.79	-	184.79	-	0.0%
2,800	199.87	199.87	-	199.87	-	0.0%
3,000	214.95	214.95	-	214.95	-	0.0%

ET-1 Winter Average Energy On-Peak: 33%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-1/E-4 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.27	20.27	-	20.27	-	0.0%
250	23.12	23.12	-	23.12	-	0.0%
300	25.97	25.97	-	25.97	-	0.0%
350	28.82	28.82	-	28.82	-	0.0%
400	31.67	31.67	-	31.67	-	0.0%
450	34.52	34.52	-	34.52	-	0.0%
500	37.37	37.37	-	37.37	-	0.0%
550	40.21	40.21	-	40.21	-	0.0%
600	43.06	43.06	-	43.06	-	0.0%
650	45.91	45.91	-	45.91	-	0.0%
700	48.76	48.76	-	48.76	-	0.0%
750	51.61	51.61	-	51.61	-	0.0%
800	54.46	54.46	-	54.46	-	0.0%
850	70.68	70.68	-	70.68	-	0.0%
900	74.19	74.19	-	74.19	-	0.0%
950	77.71	77.71	-	77.71	-	0.0%
1,000	81.22	81.22	-	81.22	-	0.0%
1,100	88.25	88.25	-	88.25	-	0.0%
1,200	95.28	95.28	-	95.28	-	0.0%
1,300	102.31	102.31	-	102.31	-	0.0%
1,400	109.33	109.33	-	109.33	-	0.0%
1,500	135.23	135.23	-	135.23	-	0.0%
1,600	143.40	143.40	-	143.40	-	0.0%
1,700	151.57	151.57	-	151.57	-	0.0%
1,800	159.73	159.73	-	159.73	-	0.0%
1,900	167.90	167.90	-	167.90	-	0.0%
2,000	176.07	176.07	-	176.07	-	0.0%
2,200	197.72	197.72	-	197.72	-	0.0%
2,400	216.72	216.72	-	216.72	-	0.0%
2,600	235.71	235.71	-	235.71	-	0.0%
2,800	254.71	254.71	-	254.71	-	0.0%
3,000	273.70	273.70	-	273.70	-	0.0%

ET-1 Summer Average Energy On-Peak: 41%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-2 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	29.73	32.13	-	32.13	2.40	8.1%
250	33.47	36.35	-	36.35	2.88	8.6%
300	37.20	40.56	-	40.56	3.36	9.0%
350	40.94	44.78	-	44.78	3.84	9.4%
400	44.67	48.99	-	48.99	4.32	9.7%
450	48.41	53.21	-	53.21	4.80	9.9%
500	52.14	57.42	-	57.42	5.28	10.1%
550	55.88	61.64	-	61.64	5.76	10.3%
600	59.61	65.85	-	65.85	6.24	10.5%
650	63.35	70.07	-	70.07	6.72	10.6%
700	67.08	74.29	-	74.29	7.21	10.7%
750	70.82	78.50	-	78.50	7.68	10.8%
800	74.55	82.72	-	82.72	8.17	11.0%
850	78.29	86.93	-	86.93	8.64	11.0%
900	82.02	91.15	-	91.15	9.13	11.1%
950	85.76	95.36	-	95.36	9.60	11.2%
1,000	89.49	99.58	-	99.58	10.09	11.3%
1,100	96.96	108.01	-	108.01	11.05	11.4%
1,200	104.43	116.44	-	116.44	12.01	11.5%
1,300	111.90	124.87	-	124.87	12.97	11.6%
1,400	119.37	133.30	-	133.30	13.93	11.7%
1,500	126.84	141.73	-	141.73	14.89	11.7%
1,600	134.31	150.16	-	150.16	15.85	11.8%
1,700	141.78	158.59	-	158.59	16.81	11.9%
1,800	149.25	167.02	-	167.02	17.77	11.9%
1,900	156.72	175.46	-	175.46	18.74	12.0%
2,000	164.19	183.89	-	183.89	19.70	12.0%
2,200	179.13	200.75	-	200.75	21.62	12.1%
2,400	194.07	217.61	-	217.61	23.54	12.1%
2,600	209.01	234.47	-	234.47	25.46	12.2%
2,800	223.96	251.33	-	251.33	27.37	12.2%
3,000	238.90	268.19	-	268.19	29.29	12.3%

ET-2 Winter Average Energy On-Peak: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-2 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	33.71	36.62	-	36.62	2.91	8.6%
250	38.44	41.96	-	41.96	3.52	9.2%
300	43.17	47.30	-	47.30	4.13	9.6%
350	47.90	52.64	-	52.64	4.74	9.9%
400	52.63	57.98	-	57.98	5.35	10.2%
450	57.36	63.31	-	63.31	5.95	10.4%
500	62.09	68.65	-	68.65	6.56	10.6%
550	66.82	73.99	-	73.99	7.17	10.7%
600	71.55	79.33	-	79.33	7.78	10.9%
650	76.28	84.67	-	84.67	8.39	11.0%
700	81.01	90.01	-	90.01	9.00	11.1%
750	85.74	95.34	-	95.34	9.60	11.2%
800	90.47	100.68	-	100.68	10.21	11.3%
850	95.20	106.02	-	106.02	10.82	11.4%
900	99.93	111.36	-	111.36	11.43	11.4%
950	104.66	116.70	-	116.70	12.04	11.5%
1,000	109.39	122.03	-	122.03	12.64	11.6%
1,100	118.85	132.71	-	132.71	13.86	11.7%
1,200	128.31	143.39	-	143.39	15.08	11.8%
1,300	137.77	154.06	-	154.06	16.29	11.8%
1,400	147.23	164.74	-	164.74	17.51	11.9%
1,500	156.69	175.42	-	175.42	18.73	12.0%
1,600	166.15	186.09	-	186.09	19.94	12.0%
1,700	175.61	196.77	-	196.77	21.16	12.0%
1,800	185.07	207.45	-	207.45	22.38	12.1%
1,900	194.53	218.12	-	218.12	23.59	12.1%
2,000	203.99	228.80	-	228.80	24.81	12.2%
2,200	222.91	250.15	-	250.15	27.24	12.2%
2,400	241.83	271.51	-	271.51	29.68	12.3%
2,600	260.75	292.86	-	292.86	32.11	12.3%
2,800	279.67	314.21	-	314.21	34.54	12.4%
3,000	298.59	335.56	-	335.56	36.97	12.4%

ET-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-2/E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.84	17.84	-	17.84	-	0.0%
250	20.08	20.08	-	20.08	-	0.0%
300	22.32	22.32	-	22.32	-	0.0%
350	24.56	24.56	-	24.56	-	0.0%
400	26.80	26.80	-	26.80	-	0.0%
450	35.82	35.82	-	35.82	-	0.0%
500	38.58	38.58	-	38.58	-	0.0%
550	41.35	41.35	-	41.35	-	0.0%
600	44.11	44.11	-	44.11	-	0.0%
650	46.88	46.88	-	46.88	-	0.0%
700	49.64	49.64	-	49.64	-	0.0%
750	52.40	52.40	-	52.40	-	0.0%
800	55.17	55.17	-	55.17	-	0.0%
850	67.33	67.33	-	67.33	-	0.0%
900	70.54	70.54	-	70.54	-	0.0%
950	73.75	73.75	-	73.75	-	0.0%
1,000	76.96	76.96	-	76.96	-	0.0%
1,100	83.39	83.39	-	83.39	-	0.0%
1,200	89.81	89.81	-	89.81	-	0.0%
1,300	98.90	98.90	-	98.90	-	0.0%
1,400	106.37	106.37	-	106.37	-	0.0%
1,500	113.84	113.84	-	113.84	-	0.0%
1,600	121.31	121.31	-	121.31	-	0.0%
1,700	128.78	128.78	-	128.78	-	0.0%
1,800	136.25	136.25	-	136.25	-	0.0%
1,900	143.72	143.72	-	143.72	-	0.0%
2,000	151.19	151.19	-	151.19	-	0.0%
2,200	166.13	166.13	-	166.13	-	0.0%
2,400	181.07	181.07	-	181.07	-	0.0%
2,600	196.01	196.01	-	196.01	-	0.0%
2,800	210.96	210.96	-	210.96	-	0.0%
3,000	225.90	225.90	-	225.90	-	0.0%

ET-2 Winter Average Energy On-Peak: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-2/E-3 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.23	20.23	-	20.23	-	0.0%
250	23.06	23.06	-	23.06	-	0.0%
300	25.90	25.90	-	25.90	-	0.0%
350	28.74	28.74	-	28.74	-	0.0%
400	31.58	31.58	-	31.58	-	0.0%
450	42.45	42.45	-	42.45	-	0.0%
500	45.95	45.95	-	45.95	-	0.0%
550	49.45	49.45	-	49.45	-	0.0%
600	52.95	52.95	-	52.95	-	0.0%
650	56.45	56.45	-	56.45	-	0.0%
700	59.95	59.95	-	59.95	-	0.0%
750	63.45	63.45	-	63.45	-	0.0%
800	66.95	66.95	-	66.95	-	0.0%
850	81.87	81.87	-	81.87	-	0.0%
900	85.94	85.94	-	85.94	-	0.0%
950	90.01	90.01	-	90.01	-	0.0%
1,000	94.08	94.08	-	94.08	-	0.0%
1,100	102.21	102.21	-	102.21	-	0.0%
1,200	110.35	110.35	-	110.35	-	0.0%
1,300	124.77	124.77	-	124.77	-	0.0%
1,400	134.23	134.23	-	134.23	-	0.0%
1,500	143.69	143.69	-	143.69	-	0.0%
1,600	153.15	153.15	-	153.15	-	0.0%
1,700	162.61	162.61	-	162.61	-	0.0%
1,800	172.07	172.07	-	172.07	-	0.0%
1,900	181.53	181.53	-	181.53	-	0.0%
2,000	190.99	190.99	-	190.99	-	0.0%
2,200	209.91	209.91	-	209.91	-	0.0%
2,400	228.83	228.83	-	228.83	-	0.0%
2,600	247.75	247.75	-	247.75	-	0.0%
2,800	266.67	266.67	-	266.67	-	0.0%
3,000	285.59	285.59	-	285.59	-	0.0%

ET-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-2/E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	17.84	17.84	-	17.84	-	0.0%
250	20.08	20.08	-	20.08	-	0.0%
300	22.32	22.32	-	22.32	-	0.0%
350	24.56	24.56	-	24.56	-	0.0%
400	26.80	26.80	-	26.80	-	0.0%
450	29.04	29.04	-	29.04	-	0.0%
500	31.28	31.28	-	31.28	-	0.0%
550	33.53	33.53	-	33.53	-	0.0%
600	35.77	35.77	-	35.77	-	0.0%
650	38.01	38.01	-	38.01	-	0.0%
700	40.25	40.25	-	40.25	-	0.0%
750	42.49	42.49	-	42.49	-	0.0%
800	44.73	44.73	-	44.73	-	0.0%
850	57.93	57.93	-	57.93	-	0.0%
900	60.70	60.70	-	60.70	-	0.0%
950	63.46	63.46	-	63.46	-	0.0%
1,000	66.22	66.22	-	66.22	-	0.0%
1,100	71.75	71.75	-	71.75	-	0.0%
1,200	77.28	77.28	-	77.28	-	0.0%
1,300	82.81	82.81	-	82.81	-	0.0%
1,400	88.34	88.34	-	88.34	-	0.0%
1,500	109.08	109.08	-	109.08	-	0.0%
1,600	115.51	115.51	-	115.51	-	0.0%
1,700	121.93	121.93	-	121.93	-	0.0%
1,800	128.36	128.36	-	128.36	-	0.0%
1,900	134.78	134.78	-	134.78	-	0.0%
2,000	141.21	141.21	-	141.21	-	0.0%
2,200	153.13	153.13	-	153.13	-	0.0%
2,400	168.07	168.07	-	168.07	-	0.0%
2,600	183.01	183.01	-	183.01	-	0.0%
2,800	197.96	197.96	-	197.96	-	0.0%
3,000	212.90	212.90	-	212.90	-	0.0%

ET-2 Winter Average Energy On-Peak: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ET-2/E-4 Summer (May - October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
200	20.23	20.23	-	20.23	-	0.0%
250	23.06	23.06	-	23.06	-	0.0%
300	25.90	25.90	-	25.90	-	0.0%
350	28.74	28.74	-	28.74	-	0.0%
400	31.58	31.58	-	31.58	-	0.0%
450	34.42	34.42	-	34.42	-	0.0%
500	37.25	37.25	-	37.25	-	0.0%
550	40.09	40.09	-	40.09	-	0.0%
600	42.93	42.93	-	42.93	-	0.0%
650	45.77	45.77	-	45.77	-	0.0%
700	48.61	48.61	-	48.61	-	0.0%
750	51.44	51.44	-	51.44	-	0.0%
800	54.28	54.28	-	54.28	-	0.0%
850	70.45	70.45	-	70.45	-	0.0%
900	73.95	73.95	-	73.95	-	0.0%
950	77.45	77.45	-	77.45	-	0.0%
1,000	80.95	80.95	-	80.95	-	0.0%
1,100	87.95	87.95	-	87.95	-	0.0%
1,200	94.95	94.95	-	94.95	-	0.0%
1,300	101.95	101.95	-	101.95	-	0.0%
1,400	108.95	108.95	-	108.95	-	0.0%
1,500	134.75	134.75	-	134.75	-	0.0%
1,600	142.89	142.89	-	142.89	-	0.0%
1,700	151.02	151.02	-	151.02	-	0.0%
1,800	159.16	159.16	-	159.16	-	0.0%
1,900	167.30	167.30	-	167.30	-	0.0%
2,000	175.43	175.43	-	175.43	-	0.0%
2,200	196.91	196.91	-	196.91	-	0.0%
2,400	215.83	215.83	-	215.83	-	0.0%
2,600	234.75	234.75	-	234.75	-	0.0%
2,800	253.67	253.67	-	253.67	-	0.0%
3,000	272.59	272.59	-	272.59	-	0.0%

ET-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (B), (C) and (D).
   Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (B) and (C) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-1R Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Monthly Bill	Components of Proposed Bill		Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	Transmission	under Proposed Rates	Amount ($)	%
						(E) + (F)	(G) - (D)	(H) / (D)
3	20%	438	56.71	62.43	-	62.43	5.72	10.1%
3	30%	657	65.45	72.26	-	72.26	6.81	10.4%
3	40%	876	74.19	82.09	-	82.09	7.90	10.6%
3	50%	1,095	82.93	91.92	-	91.92	8.99	10.8%
3	75%	1,643	104.79	116.52	-	116.52	11.73	11.2%
5	20%	730	84.66	93.87	-	93.87	9.21	10.9%
5	30%	1,095	99.23	110.26	-	110.26	11.03	11.1%
5	40%	1,460	113.79	126.64	-	126.64	12.85	11.3%
5	50%	1,825	128.35	143.02	-	143.02	14.67	11.4%
5	75%	2,738	164.78	184.00	-	184.00	19.22	11.7%
8	20%	1,168	126.59	141.04	-	141.04	14.45	11.4%
8	30%	1,752	149.89	167.25	-	167.25	17.36	11.6%
8	40%	2,336	173.19	193.46	-	193.46	20.27	11.7%
8	50%	2,920	196.49	219.67	-	219.67	23.18	11.8%
8	75%	4,380	254.74	285.20	-	285.20	30.46	12.0%
10	20%	1,460	154.54	172.48	-	172.48	17.94	11.6%
10	30%	2,190	183.66	205.24	-	205.24	21.58	11.7%
10	40%	2,920	212.79	238.01	-	238.01	25.22	11.9%
10	50%	3,650	241.91	270.77	-	270.77	28.86	11.9%
10	75%	5,475	314.72	352.68	-	352.68	37.96	12.1%
12	20%	1,752	182.49	203.92	-	203.92	21.43	11.7%
12	30%	2,628	217.44	243.24	-	243.24	25.80	11.9%
12	40%	3,504	252.39	282.55	-	282.55	30.16	11.9%
12	50%	4,380	287.34	321.87	-	321.87	34.53	12.0%
12	75%	6,570	374.71	420.16	-	420.16	45.45	12.1%
15	20%	2,190	224.41	251.08	-	251.08	26.67	11.9%
15	30%	3,285	268.10	300.23	-	300.23	32.13	12.0%
15	40%	4,380	311.79	349.37	-	349.37	37.58	12.1%
15	50%	5,475	355.47	398.52	-	398.52	43.05	12.1%
15	75%	8,213	464.71	521.41	-	521.41	56.70	12.2%

ECT-1R Winter Average Energy On-Peak: 32%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-1R Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	71.62	79.20	-	79.20	7.58	10.6%
3	30%	657	82.24	91.15	-	91.15	8.91	10.8%
3	40%	876	92.86	103.10	-	103.10	10.24	11.0%
3	50%	1,095	103.48	115.05	-	115.05	11.57	11.2%
3	75%	1,643	130.07	144.95	-	144.95	14.88	11.4%
5	20%	730	109.50	121.81	-	121.81	12.31	11.2%
5	30%	1,095	127.20	141.73	-	141.73	14.53	11.4%
5	40%	1,460	144.91	161.65	-	161.65	16.74	11.6%
5	50%	1,825	162.61	181.56	-	181.56	18.95	11.7%
5	75%	2,738	206.90	231.38	-	231.38	24.48	11.8%
8	20%	1,168	166.33	185.74	-	185.74	19.41	11.7%
8	30%	1,752	194.65	217.60	-	217.60	22.95	11.8%
8	40%	2,336	222.98	249.47	-	249.47	26.49	11.9%
8	50%	2,920	251.31	281.34	-	281.34	30.03	11.9%
8	75%	4,380	322.13	361.00	-	361.00	38.87	12.1%
10	20%	1,460	204.21	228.35	-	228.35	24.14	11.8%
10	30%	2,190	239.62	268.19	-	268.19	28.57	11.9%
10	40%	2,920	275.03	308.02	-	308.02	32.99	12.0%
10	50%	3,650	310.44	347.86	-	347.86	37.42	12.1%
10	75%	5,475	398.96	447.44	-	447.44	48.48	12.2%
12	20%	1,752	242.09	270.97	-	270.97	28.88	11.9%
12	30%	2,628	284.58	318.77	-	318.77	34.19	12.0%
12	40%	3,504	327.08	366.57	-	366.57	39.49	12.1%
12	50%	4,380	369.57	414.37	-	414.37	44.80	12.1%
12	75%	6,570	475.79	533.87	-	533.87	58.08	12.2%
15	20%	2,190	298.92	334.90	-	334.90	35.98	12.0%
15	30%	3,285	352.03	394.65	-	394.65	42.62	12.1%
15	40%	4,380	405.15	454.40	-	454.40	49.25	12.2%
15	50%	5,475	458.26	514.15	-	514.15	55.89	12.2%
15	75%	8,213	591.07	663.55	-	663.55	72.48	12.3%

ECT-1R Summer Average Energy On-Peak: 40%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-1R/E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	41.92	41.92	-	41.92	-	0.0%
3	30%	657	48.36	48.36	-	48.36	-	0.0%
3	40%	876	63.69	63.69	-	63.69	-	0.0%
3	50%	1,095	71.18	71.18	-	71.18	-	0.0%
3	75%	1,643	91.55	91.55	-	91.55	-	0.0%
5	20%	730	62.57	62.57	-	62.57	-	0.0%
5	30%	1,095	85.20	85.20	-	85.20	-	0.0%
5	40%	1,460	100.58	100.58	-	100.58	-	0.0%
5	50%	1,825	115.09	115.09	-	115.09	-	0.0%
5	75%	2,738	151.38	151.38	-	151.38	-	0.0%
8	20%	1,168	108.72	108.72	-	108.72	-	0.0%
8	30%	1,752	136.64	136.64	-	136.64	-	0.0%
8	40%	2,336	159.85	159.85	-	159.85	-	0.0%
8	50%	2,920	183.07	183.07	-	183.07	-	0.0%
8	75%	4,380	241.10	241.10	-	241.10	-	0.0%
10	20%	1,460	141.33	141.33	-	141.33	-	0.0%
10	30%	2,190	170.35	170.35	-	170.35	-	0.0%
10	40%	2,920	199.37	199.37	-	199.37	-	0.0%
10	50%	3,650	228.38	228.38	-	228.38	-	0.0%
10	75%	5,475	300.93	300.93	-	300.93	-	0.0%
12	20%	1,752	169.24	169.24	-	169.24	-	0.0%
12	30%	2,628	204.06	204.06	-	204.06	-	0.0%
12	40%	3,504	238.88	238.88	-	238.88	-	0.0%
12	50%	4,380	273.70	273.70	-	273.70	-	0.0%
12	75%	6,570	360.76	360.76	-	360.76	-	0.0%
15	20%	2,190	211.10	211.10	-	211.10	-	0.0%
15	30%	3,285	254.62	254.62	-	254.62	-	0.0%
15	40%	4,380	298.15	298.15	-	298.15	-	0.0%
15	50%	5,475	341.68	341.68	-	341.68	-	0.0%
15	75%	8,213	450.52	450.52	-	450.52	-	0.0%

ECT-1R Winter Average Energy On-Peak: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-1R/E-3 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Monthly Bill	Components of Proposed Bill		Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	Transmission	under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	53.00	53.00	-	53.00	-	0.0%
3	30%	657	60.86	60.86	-	60.86	-	0.0%
3	40%	876	79.86	79.86	-	79.86	-	0.0%
3	50%	1,095	89.00	89.00	-	89.00	-	0.0%
3	75%	1,643	117.07	117.07	-	117.07	-	0.0%
5	20%	730	81.03	81.03	-	81.03	-	0.0%
5	30%	1,095	109.40	109.40	-	109.40	-	0.0%
5	40%	1,460	131.91	131.91	-	131.91	-	0.0%
5	50%	1,825	149.61	149.61	-	149.61	-	0.0%
5	75%	2,738	193.90	193.90	-	193.90	-	0.0%
8	20%	1,168	143.04	143.04	-	143.04	-	0.0%
8	30%	1,752	181.65	181.65	-	181.65	-	0.0%
8	40%	2,336	209.98	209.98	-	209.98	-	0.0%
8	50%	2,920	238.31	238.31	-	238.31	-	0.0%
8	75%	4,380	309.13	309.13	-	309.13	-	0.0%
10	20%	1,460	191.21	191.21	-	191.21	-	0.0%
10	30%	2,190	226.62	226.62	-	226.62	-	0.0%
10	40%	2,920	262.03	262.03	-	262.03	-	0.0%
10	50%	3,650	297.44	297.44	-	297.44	-	0.0%
10	75%	5,475	385.96	385.96	-	385.96	-	0.0%
12	20%	1,752	229.09	229.09	-	229.09	-	0.0%
12	30%	2,628	271.58	271.58	-	271.58	-	0.0%
12	40%	3,504	314.08	314.08	-	314.08	-	0.0%
12	50%	4,380	356.57	356.57	-	356.57	-	0.0%
12	75%	6,570	462.79	462.79	-	462.79	-	0.0%
15	20%	2,190	285.92	285.92	-	285.92	-	0.0%
15	30%	3,285	339.03	339.03	-	339.03	-	0.0%
15	40%	4,380	392.15	392.15	-	392.15	-	0.0%
15	50%	5,475	445.26	445.26	-	445.26	-	0.0%
15	75%	8,213	578.07	578.07	-	578.07	-	0.0%

ECT-1R Summer Average Energy On-Peak: 40%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-1R/E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	34.03	34.03	-	34.03	-	0.0%
3	30%	657	39.27	39.27	-	39.27	-	0.0%
3	40%	876	44.51	44.51	-	44.51	-	0.0%
3	50%	1,095	49.76	49.76	-	49.76	-	0.0%
3	75%	1,643	62.87	62.87	-	62.87	-	0.0%
5	20%	730	50.80	50.80	-	50.80	-	0.0%
5	30%	1,095	59.54	59.54	-	59.54	-	0.0%
5	40%	1,460	68.27	68.27	-	68.27	-	0.0%
5	50%	1,825	77.01	77.01	-	77.01	-	0.0%
5	75%	2,738	98.87	98.87	-	98.87	-	0.0%
8	20%	1,168	75.95	75.95	-	75.95	-	0.0%
8	30%	1,752	89.93	89.93	-	89.93	-	0.0%
8	40%	2,336	103.91	103.91	-	103.91	-	0.0%
8	50%	2,920	117.89	117.89	-	117.89	-	0.0%
8	75%	4,380	152.84	152.84	-	152.84	-	0.0%
10	20%	1,460	92.72	92.72	-	92.72	-	0.0%
10	30%	2,190	110.20	110.20	-	110.20	-	0.0%
10	40%	2,920	127.67	127.67	-	127.67	-	0.0%
10	50%	3,650	145.15	145.15	-	145.15	-	0.0%
10	75%	5,475	188.83	188.83	-	188.83	-	0.0%
12	20%	1,752	109.49	109.49	-	109.49	-	0.0%
12	30%	2,628	130.46	130.46	-	130.46	-	0.0%
12	40%	3,504	151.43	151.43	-	151.43	-	0.0%
12	50%	4,380	172.40	172.40	-	172.40	-	0.0%
12	75%	6,570	224.83	224.83	-	224.83	-	0.0%
15	20%	2,190	134.65	134.65	-	134.65	-	0.0%
15	30%	3,285	160.86	160.86	-	160.86	-	0.0%
15	40%	4,380	187.07	187.07	-	187.07	-	0.0%
15	50%	5,475	213.28	213.28	-	213.28	-	0.0%
15	75%	8,213	278.83	278.83	-	278.83	-	0.0%

ECT-1R Winter Average Energy On-Peak: 32%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-1R/E-4 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	42.97	42.97	-	42.97	-	0.0%
3	30%	657	49.34	49.34	-	49.34	-	0.0%
3	40%	876	68.72	68.72	-	68.72	-	0.0%
3	50%	1,095	76.58	76.58	-	76.58	-	0.0%
3	75%	1,643	111.86	111.86	-	111.86	-	0.0%
5	20%	730	65.70	65.70	-	65.70	-	0.0%
5	30%	1,095	94.13	94.13	-	94.13	-	0.0%
5	40%	1,460	124.62	124.62	-	124.62	-	0.0%
5	50%	1,825	139.85	139.85	-	139.85	-	0.0%
5	75%	2,738	180.90	180.90	-	180.90	-	0.0%
8	20%	1,168	123.08	123.08	-	123.08	-	0.0%
8	30%	1,752	167.40	167.40	-	167.40	-	0.0%
8	40%	2,336	196.98	196.98	-	196.98	-	0.0%
8	50%	2,920	225.31	225.31	-	225.31	-	0.0%
8	75%	4,380	296.13	296.13	-	296.13	-	0.0%
10	20%	1,460	175.62	175.62	-	175.62	-	0.0%
10	30%	2,190	213.62	213.62	-	213.62	-	0.0%
10	40%	2,920	249.03	249.03	-	249.03	-	0.0%
10	50%	3,650	284.44	284.44	-	284.44	-	0.0%
10	75%	5,475	372.96	372.96	-	372.96	-	0.0%
12	20%	1,752	208.20	208.20	-	208.20	-	0.0%
12	30%	2,628	258.58	258.58	-	258.58	-	0.0%
12	40%	3,504	301.08	301.08	-	301.08	-	0.0%
12	50%	4,380	343.57	343.57	-	343.57	-	0.0%
12	75%	6,570	449.79	449.79	-	449.79	-	0.0%
15	20%	2,190	272.92	272.92	-	272.92	-	0.0%
15	30%	3,285	326.03	326.03	-	326.03	-	0.0%
15	40%	4,380	379.15	379.15	-	379.15	-	0.0%
15	50%	5,475	432.26	432.26	-	432.26	-	0.0%
15	75%	8,213	565.07	565.07	-	565.07	-	0.0%

ECT-1R Summer Average Energy On-Peak: 40%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-2 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	56.83	62.60	-	62.60	5.77	10.2%
3	30%	657	65.63	72.51	-	72.51	6.88	10.5%
3	40%	876	74.42	82.41	-	82.41	7.99	10.7%
3	50%	1,095	83.22	92.31	-	92.31	9.09	10.9%
3	75%	1,643	105.23	117.09	-	117.09	11.86	11.3%
5	20%	730	84.86	94.16	-	94.16	9.30	11.0%
5	30%	1,095	99.52	110.66	-	110.66	11.14	11.2%
5	40%	1,460	114.18	127.17	-	127.17	12.99	11.4%
5	50%	1,825	128.84	143.67	-	143.67	14.83	11.5%
5	75%	2,738	165.50	184.96	-	184.96	19.46	11.8%
8	20%	1,168	126.90	141.49	-	141.49	14.59	11.5%
8	30%	1,752	150.35	167.90	-	167.90	17.55	11.7%
8	40%	2,336	173.81	194.31	-	194.31	20.50	11.8%
8	50%	2,920	197.26	220.72	-	220.72	23.46	11.9%
8	75%	4,380	255.90	286.74	-	286.74	30.84	12.1%
10	20%	1,460	154.93	173.05	-	173.05	18.12	11.7%
10	30%	2,190	184.25	206.06	-	206.06	21.81	11.8%
10	40%	2,920	213.56	239.07	-	239.07	25.51	11.9%
10	50%	3,650	242.88	272.08	-	272.08	29.20	12.0%
10	75%	5,475	316.18	354.60	-	354.60	38.42	12.2%
12	20%	1,752	182.95	204.61	-	204.61	21.66	11.8%
12	30%	2,628	218.14	244.22	-	244.22	26.08	12.0%
12	40%	3,504	253.32	283.83	-	283.83	30.51	12.0%
12	50%	4,380	288.50	323.44	-	323.44	34.94	12.1%
12	75%	6,570	376.46	422.47	-	422.47	46.01	12.2%
15	20%	2,190	225.00	251.94	-	251.94	26.94	12.0%
15	30%	3,285	268.97	301.45	-	301.45	32.48	12.1%
15	40%	4,380	312.95	350.97	-	350.97	38.02	12.1%
15	50%	5,475	356.93	400.48	-	400.48	43.55	12.2%
15	75%	8,213	466.89	524.29	-	524.29	57.40	12.3%

ECT-2 Winter Average Energy On-Peak: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-2 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	71.67	79.31	-	79.31	7.64	10.7%
3	30%	657	82.31	91.29	-	91.29	8.98	10.9%
3	40%	876	92.94	103.26	-	103.26	10.32	11.1%
3	50%	1,095	103.58	115.23	-	115.23	11.65	11.2%
3	75%	1,643	130.19	145.20	-	145.20	15.01	11.5%
5	20%	730	109.59	122.01	-	122.01	12.42	11.3%
5	30%	1,095	127.32	141.96	-	141.96	14.64	11.5%
5	40%	1,460	145.04	161.92	-	161.92	16.88	11.6%
5	50%	1,825	162.77	181.88	-	181.88	19.11	11.7%
5	75%	2,738	207.10	231.80	-	231.80	24.70	11.9%
8	20%	1,168	166.47	186.05	-	186.05	19.58	11.8%
8	30%	1,752	194.83	217.98	-	217.98	23.15	11.9%
8	40%	2,336	223.19	249.91	-	249.91	26.72	12.0%
8	50%	2,920	251.55	281.84	-	281.84	30.29	12.0%
8	75%	4,380	322.45	361.67	-	361.67	39.22	12.2%
10	20%	1,460	204.39	228.74	-	228.74	24.35	11.9%
10	30%	2,190	239.84	268.66	-	268.66	28.82	12.0%
10	40%	2,920	275.29	308.57	-	308.57	33.28	12.1%
10	50%	3,650	310.74	348.48	-	348.48	37.74	12.1%
10	75%	5,475	399.37	448.27	-	448.27	48.90	12.2%
12	20%	1,752	242.31	271.44	-	271.44	29.13	12.0%
12	30%	2,628	284.85	319.33	-	319.33	34.48	12.1%
12	40%	3,504	327.39	367.23	-	367.23	39.84	12.2%
12	50%	4,380	369.93	415.13	-	415.13	45.20	12.2%
12	75%	6,570	476.29	534.87	-	534.87	58.58	12.3%
15	20%	2,190	299.19	335.48	-	335.48	36.29	12.1%
15	30%	3,285	352.37	395.35	-	395.35	42.98	12.2%
15	40%	4,380	405.54	455.22	-	455.22	49.68	12.3%
15	50%	5,475	458.72	515.09	-	515.09	56.37	12.3%
15	75%	8,213	591.68	664.79	-	664.79	73.11	12.4%

ECT-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-2/E-3 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	42.05	42.05	-	42.05	-	0.0%
3	30%	657	48.56	48.56	-	48.56	-	0.0%
3	40%	876	64.00	64.00	-	64.00	-	0.0%
3	50%	1,095	71.57	71.57	-	71.57	-	0.0%
3	75%	1,643	92.23	92.23	-	92.23	-	0.0%
5	20%	730	62.80	62.80	-	62.80	-	0.0%
5	30%	1,095	85.59	85.59	-	85.59	-	0.0%
5	40%	1,460	101.18	101.18	-	101.18	-	0.0%
5	50%	1,825	115.84	115.84	-	115.84	-	0.0%
5	75%	2,738	152.50	152.50	-	152.50	-	0.0%
8	20%	1,168	109.13	109.13	-	109.13	-	0.0%
8	30%	1,752	137.35	137.35	-	137.35	-	0.0%
8	40%	2,336	160.81	160.81	-	160.81	-	0.0%
8	50%	2,920	184.26	184.26	-	184.26	-	0.0%
8	75%	4,380	242.90	242.90	-	242.90	-	0.0%
10	20%	1,460	141.93	141.93	-	141.93	-	0.0%
10	30%	2,190	171.25	171.25	-	171.25	-	0.0%
10	40%	2,920	200.56	200.56	-	200.56	-	0.0%
10	50%	3,650	229.88	229.88	-	229.88	-	0.0%
10	75%	5,475	303.18	303.18	-	303.18	-	0.0%
12	20%	1,752	169.95	169.95	-	169.95	-	0.0%
12	30%	2,628	205.14	205.14	-	205.14	-	0.0%
12	40%	3,504	240.32	240.32	-	240.32	-	0.0%
12	50%	4,380	275.50	275.50	-	275.50	-	0.0%
12	75%	6,570	363.46	363.46	-	363.46	-	0.0%
15	20%	2,190	212.00	212.00	-	212.00	-	0.0%
15	30%	3,285	255.97	255.97	-	255.97	-	0.0%
15	40%	4,380	299.95	299.95	-	299.95	-	0.0%
15	50%	5,475	343.93	343.93	-	343.93	-	0.0%
15	75%	8,213	453.89	453.89	-	453.89	-	0.0%

ECT-2 Winter Average Energy On-Peak: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-2/E-3 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	53.04	53.04	-	53.04	-	0.0%
3	30%	657	60.91	60.91	-	60.91	-	0.0%
3	40%	876	79.93	79.93	-	79.93	-	0.0%
3	50%	1,095	89.08	89.08	-	89.08	-	0.0%
3	75%	1,643	117.19	117.19	-	117.19	-	0.0%
5	20%	730	81.10	81.10	-	81.10	-	0.0%
5	30%	1,095	109.49	109.49	-	109.49	-	0.0%
5	40%	1,460	132.04	132.04	-	132.04	-	0.0%
5	50%	1,825	149.77	149.77	-	149.77	-	0.0%
5	75%	2,738	194.10	194.10	-	194.10	-	0.0%
8	20%	1,168	143.17	143.17	-	143.17	-	0.0%
8	30%	1,752	181.83	181.83	-	181.83	-	0.0%
8	40%	2,336	210.19	210.19	-	210.19	-	0.0%
8	50%	2,920	238.55	238.55	-	238.55	-	0.0%
8	75%	4,380	309.45	309.45	-	309.45	-	0.0%
10	20%	1,460	191.39	191.39	-	191.39	-	0.0%
10	30%	2,190	226.84	226.84	-	226.84	-	0.0%
10	40%	2,920	262.29	262.29	-	262.29	-	0.0%
10	50%	3,650	297.74	297.74	-	297.74	-	0.0%
10	75%	5,475	386.37	386.37	-	386.37	-	0.0%
12	20%	1,752	229.31	229.31	-	229.31	-	0.0%
12	30%	2,628	271.85	271.85	-	271.85	-	0.0%
12	40%	3,504	314.39	314.39	-	314.39	-	0.0%
12	50%	4,380	356.93	356.93	-	356.93	-	0.0%
12	75%	6,570	463.29	463.29	-	463.29	-	0.0%
15	20%	2,190	286.19	286.19	-	286.19	-	0.0%
15	30%	3,285	339.37	339.37	-	339.37	-	0.0%
15	40%	4,380	392.54	392.54	-	392.54	-	0.0%
15	50%	5,475	445.72	445.72	-	445.72	-	0.0%
15	75%	8,213	578.68	578.68	-	578.68	-	0.0%

ECT-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-2/E-4 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	34.10	34.10	-	34.10	-	0.0%
3	30%	657	39.38	39.38	-	39.38	-	0.0%
3	40%	876	44.65	44.65	-	44.65	-	0.0%
3	50%	1,095	49.93	49.93	-	49.93	-	0.0%
3	75%	1,643	63.14	63.14	-	63.14	-	0.0%
5	20%	730	50.92	50.92	-	50.92	-	0.0%
5	30%	1,095	59.71	59.71	-	59.71	-	0.0%
5	40%	1,460	68.51	68.51	-	68.51	-	0.0%
5	50%	1,825	77.30	77.30	-	77.30	-	0.0%
5	75%	2,738	99.30	99.30	-	99.30	-	0.0%
8	20%	1,168	76.14	76.14	-	76.14	-	0.0%
8	30%	1,752	90.21	90.21	-	90.21	-	0.0%
8	40%	2,336	104.29	104.29	-	104.29	-	0.0%
8	50%	2,920	118.36	118.36	-	118.36	-	0.0%
8	75%	4,380	153.54	153.54	-	153.54	-	0.0%
10	20%	1,460	92.96	92.96	-	92.96	-	0.0%
10	30%	2,190	110.55	110.55	-	110.55	-	0.0%
10	40%	2,920	128.14	128.14	-	128.14	-	0.0%
10	50%	3,650	145.73	145.73	-	145.73	-	0.0%
10	75%	5,475	189.71	189.71	-	189.71	-	0.0%
12	20%	1,752	109.77	109.77	-	109.77	-	0.0%
12	30%	2,628	130.88	130.88	-	130.88	-	0.0%
12	40%	3,504	151.99	151.99	-	151.99	-	0.0%
12	50%	4,380	173.10	173.10	-	173.10	-	0.0%
12	75%	6,570	225.87	225.87	-	225.87	-	0.0%
15	20%	2,190	135.00	135.00	-	135.00	-	0.0%
15	30%	3,285	161.38	161.38	-	161.38	-	0.0%
15	40%	4,380	187.77	187.77	-	187.77	-	0.0%
15	50%	5,475	214.16	214.16	-	214.16	-	0.0%
15	75%	8,213	280.14	280.14	-	280.14	-	0.0%

ECT-2 Winter Average Energy On-Peak: 17%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Residential Bill Analysis
ECT-2/E-4 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3	20%	438	43.00	43.00	-	43.00	-	0.0%
3	30%	657	49.38	49.38	-	49.38	-	0.0%
3	40%	876	68.78	68.78	-	68.78	-	0.0%
3	50%	1,095	76.65	76.65	-	76.65	-	0.0%
3	75%	1,643	111.96	111.96	-	111.96	-	0.0%
5	20%	730	65.75	65.75	-	65.75	-	0.0%
5	30%	1,095	94.21	94.21	-	94.21	-	0.0%
5	40%	1,460	124.74	124.74	-	124.74	-	0.0%
5	50%	1,825	139.98	139.98	-	139.98	-	0.0%
5	75%	2,738	181.10	181.10	-	181.10	-	0.0%
8	20%	1,168	123.19	123.19	-	123.19	-	0.0%
8	30%	1,752	167.56	167.56	-	167.56	-	0.0%
8	40%	2,336	197.19	197.19	-	197.19	-	0.0%
8	50%	2,920	225.55	225.55	-	225.55	-	0.0%
8	75%	4,380	296.45	296.45	-	296.45	-	0.0%
10	20%	1,460	175.78	175.78	-	175.78	-	0.0%
10	30%	2,190	213.84	213.84	-	213.84	-	0.0%
10	40%	2,920	249.29	249.29	-	249.29	-	0.0%
10	50%	3,650	284.74	284.74	-	284.74	-	0.0%
10	75%	5,475	373.37	373.37	-	373.37	-	0.0%
12	20%	1,752	208.39	208.39	-	208.39	-	0.0%
12	30%	2,628	258.85	258.85	-	258.85	-	0.0%
12	40%	3,504	301.39	301.39	-	301.39	-	0.0%
12	50%	4,380	343.93	343.93	-	343.93	-	0.0%
12	75%	6,570	450.29	450.29	-	450.29	-	0.0%
15	20%	2,190	273.19	273.19	-	273.19	-	0.0%
15	30%	3,285	326.37	326.37	-	326.37	-	0.0%
15	40%	4,380	379.54	379.54	-	379.54	-	0.0%
15	50%	5,475	432.72	432.72	-	432.72	-	0.0%
15	75%	8,213	565.68	565.68	-	565.68	-	0.0%

ECT-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Appropriate percentage discounts have been applied to columns (D), (E) and (F).
Flat dollar discounts (customers with usage 1201 kWh and above) are applied to columns (D) and (E) only.
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-20 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
15	20%	2,190	215.75	245.00	-	245.00	29.25	13.6%
15	30%	3,285	295.22	334.09	-	334.09	38.87	13.2%
15	40%	4,380	374.69	423.17	-	423.17	48.48	12.9%
15	50%	5,475	454.16	512.26	-	512.26	58.10	12.8%
15	75%	8,213	652.88	735.02	-	735.02	82.14	12.6%
30	20%	4,380	403.27	455.21	-	455.21	51.94	12.9%
30	30%	6,570	562.21	633.38	-	633.38	71.17	12.7%
30	40%	8,760	721.15	811.56	-	811.56	90.41	12.5%
30	50%	10,950	880.10	989.73	-	989.73	109.63	12.5%
30	75%	16,425	1,277.46	1,435.17	-	1,435.17	157.71	12.3%
50	20%	7,300	653.29	735.49	-	735.49	82.20	12.6%
50	30%	10,950	918.20	1,032.44	-	1,032.44	114.24	12.4%
50	40%	14,600	1,183.10	1,329.40	-	1,329.40	146.30	12.4%
50	50%	18,250	1,448.01	1,626.36	-	1,626.36	178.35	12.3%
50	75%	27,375	2,110.28	2,368.76	-	2,368.76	258.48	12.2%
100	20%	14,600	1,278.35	1,436.18	-	1,436.18	157.83	12.3%
100	30%	21,900	1,808.17	2,030.10	-	2,030.10	221.93	12.3%
100	40%	29,200	2,337.98	2,624.02	-	2,624.02	286.04	12.2%
100	50%	36,500	2,867.79	3,217.94	-	3,217.94	350.15	12.2%
100	75%	54,750	4,192.32	4,702.74	-	4,702.74	510.42	12.2%
150	20%	21,900	1,903.42	2,136.87	-	2,136.87	233.45	12.3%
150	30%	32,850	2,698.13	3,027.75	-	3,027.75	329.62	12.2%
150	40%	43,800	3,492.85	3,918.63	-	3,918.63	425.78	12.2%
150	50%	54,750	4,287.57	4,809.51	-	4,809.51	521.94	12.2%
150	75%	82,125	6,274.37	7,036.71	-	7,036.71	762.34	12.2%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-20 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
15	20%	2,190	238.88	270.93	-	270.93	32.05	13.4%
15	30%	3,285	328.36	371.24	-	371.24	42.88	13.1%
15	40%	4,380	417.85	471.55	-	471.55	53.70	12.9%
15	50%	5,475	507.33	571.86	-	571.86	64.53	12.7%
15	75%	8,213	731.08	822.69	-	822.69	91.61	12.5%
30	20%	4,380	449.53	507.06	-	507.06	57.53	12.8%
30	30%	6,570	628.50	707.69	-	707.69	79.19	12.6%
30	40%	8,760	807.46	908.31	-	908.31	100.85	12.5%
30	50%	10,950	986.43	1,108.94	-	1,108.94	122.51	12.4%
30	75%	16,425	1,433.85	1,610.50	-	1,610.50	176.65	12.3%
50	20%	7,300	730.39	821.91	-	821.91	91.52	12.5%
50	30%	10,950	1,028.67	1,156.29	-	1,156.29	127.62	12.4%
50	40%	14,600	1,326.95	1,490.66	-	1,490.66	163.71	12.3%
50	50%	18,250	1,625.23	1,825.03	-	1,825.03	199.80	12.3%
50	75%	27,375	2,370.94	2,660.97	-	2,660.97	290.03	12.2%
100	20%	14,600	1,432.55	1,609.04	-	1,609.04	176.49	12.3%
100	30%	21,900	2,029.12	2,277.78	-	2,277.78	248.66	12.3%
100	40%	29,200	2,625.68	2,946.53	-	2,946.53	320.85	12.2%
100	50%	36,500	3,222.24	3,615.27	-	3,615.27	393.03	12.2%
100	75%	54,750	4,713.64	5,287.14	-	5,287.14	573.50	12.2%
150	20%	21,900	2,134.72	2,396.16	-	2,396.16	261.44	12.2%
150	30%	32,850	3,029.56	3,399.28	-	3,399.28	369.72	12.2%
150	40%	43,800	3,924.40	4,402.40	-	4,402.40	478.00	12.2%
150	50%	54,750	4,819.24	5,405.52	-	5,405.52	586.28	12.2%
150	75%	82,125	7,056.35	7,913.31	-	7,913.31	856.96	12.1%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-30 Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
30	11.69	13.75	-	13.75	2.06	17.6%
40	12.84	14.94	-	14.94	2.10	16.4%
50	13.99	16.14	-	16.14	2.15	15.4%
60	15.13	17.33	-	17.33	2.20	14.5%
70	16.28	18.52	-	18.52	2.24	13.8%
80	17.43	19.72	-	19.72	2.29	13.1%
90	18.57	20.91	-	20.91	2.34	12.6%
100	19.72	22.10	-	22.10	2.38	12.1%
125	22.59	25.09	-	25.09	2.50	11.1%
150	25.46	28.07	-	28.07	2.61	10.3%
175	28.33	31.06	-	31.06	2.73	9.6%
200	31.19	34.04	-	34.04	2.85	9.1%
225	34.06	37.02	-	37.02	2.96	8.7%
250	36.93	40.01	-	40.01	3.08	8.3%
275	39.80	42.99	-	42.99	3.19	8.0%
300	42.67	45.98	-	45.98	3.31	7.8%
325	45.53	48.96	-	48.96	3.43	7.5%
350	48.40	51.95	-	51.95	3.55	7.3%
375	51.27	54.93	-	54.93	3.66	7.1%
400	54.14	57.91	-	57.91	3.77	7.0%
425	57.01	60.90	-	60.90	3.89	6.8%
450	59.87	63.88	-	63.88	4.01	6.7%
475	62.74	66.87	-	66.87	4.13	6.6%
500	65.61	69.85	-	69.85	4.24	6.5%
600	77.08	81.79	-	81.79	4.71	6.1%
700	88.55	93.72	-	93.72	5.17	5.8%
800	100.03	105.66	-	105.66	5.63	5.6%
900	111.50	117.60	-	117.60	6.10	5.5%
1,000	122.97	129.53	-	129.53	6.56	5.3%
1,500	180.33	189.22	-	189.22	8.89	4.9%
2,000	237.69	248.90	-	248.90	11.21	4.7%
2,500	295.05	308.58	-	308.58	13.53	4.6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-30 Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (C) + (D)	Amount ($) (E) - (B)	% (F) / (B)
30	12.08	14.16	-	14.16	2.08	17.2%
40	13.36	15.49	-	15.49	2.13	15.9%
50	14.64	16.82	-	16.82	2.18	14.9%
60	15.92	18.15	-	18.15	2.23	14.0%
70	17.20	19.48	-	19.48	2.28	13.3%
80	18.48	20.81	-	20.81	2.33	12.6%
90	19.75	22.14	-	22.14	2.39	12.1%
100	21.03	23.47	-	23.47	2.44	11.6%
125	24.23	26.79	-	26.79	2.56	10.6%
150	27.42	30.12	-	30.12	2.70	9.8%
175	30.62	33.44	-	33.44	2.82	9.2%
200	33.81	36.77	-	36.77	2.96	8.8%
225	37.01	40.09	-	40.09	3.08	8.3%
250	40.21	43.42	-	43.42	3.21	8.0%
275	43.40	46.74	-	46.74	3.34	7.7%
300	46.60	50.07	-	50.07	3.47	7.4%
325	49.79	53.39	-	53.39	3.60	7.2%
350	52.99	56.72	-	56.72	3.73	7.0%
375	56.18	60.04	-	60.04	3.86	6.9%
400	59.38	63.37	-	63.37	3.99	6.7%
425	62.57	66.69	-	66.69	4.12	6.6%
450	65.77	70.02	-	70.02	4.25	6.5%
475	68.96	73.34	-	73.34	4.38	6.4%
500	72.16	76.67	-	76.67	4.51	6.3%
600	84.94	89.97	-	89.97	5.03	5.9%
700	97.72	103.26	-	103.26	5.54	5.7%
800	110.51	116.56	-	116.56	6.05	5.5%
900	123.29	129.86	-	129.86	6.57	5.3%
1,000	136.07	143.16	-	143.16	7.09	5.2%
1,500	199.98	209.66	-	209.66	9.68	4.8%
2,000	263.89	276.16	-	276.16	12.27	4.6%
2,500	327.80	342.66	-	342.66	14.86	4.5%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 XS Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
5	15%	548	71.66	78.11	-	78.11	6.45	9.0%
5	30%	1,095	125.97	138.81	-	138.81	12.84	10.2%
5	45%	1,643	180.38	199.62	-	199.62	19.24	10.7%
5	60%	2,190	234.70	260.32	-	260.32	25.62	10.9%
5	75%	2,738	289.11	321.13	-	321.13	32.02	11.1%
10	15%	1,095	125.97	138.81	-	138.81	12.84	10.2%
10	30%	2,190	234.70	260.32	-	260.32	25.62	10.9%
10	45%	3,285	343.42	381.83	-	381.83	38.41	11.2%
10	60%	4,380	452.14	503.34	-	503.34	51.20	11.3%
10	75%	5,475	536.24	597.47	-	597.47	61.23	11.4%
15	15%	1,643	180.38	199.62	-	199.62	19.24	10.7%
15	30%	3,285	343.42	381.83	-	381.83	38.41	11.2%
15	45%	4,928	506.55	564.15	-	564.15	57.60	11.4%
15	60%	6,570	588.20	655.87	-	655.87	67.67	11.5%
15	75%	8,213	666.16	743.49	-	743.49	77.33	11.6%
20	15%	2,190	234.70	260.32	-	260.32	25.62	10.9%
20	30%	4,380	452.14	503.34	-	503.34	51.20	11.3%
20	45%	6,570	588.20	655.87	-	655.87	67.67	11.5%
20	60%	8,760	692.11	772.66	-	772.66	80.55	11.6%
20	75%	10,950	796.03	889.45	-	889.45	93.42	11.7%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 XS Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
5	15%	548	79.93	89.67	-	89.67	9.74	12.2%
5	30%	1,095	142.50	161.91	-	161.91	19.41	13.6%
5	45%	1,643	205.18	234.28	-	234.28	29.10	14.2%
5	60%	2,190	267.74	306.53	-	306.53	38.79	14.5%
5	75%	2,738	330.42	378.90	-	378.90	48.48	14.7%
10	15%	1,095	142.50	161.91	-	161.91	19.41	13.6%
10	30%	2,190	267.74	306.53	-	306.53	38.79	14.5%
10	45%	3,285	392.99	451.14	-	451.14	58.15	14.8%
10	60%	4,380	518.23	595.76	-	595.76	77.53	15.0%
10	75%	5,475	618.86	712.99	-	712.99	94.13	15.2%
15	15%	1,643	205.18	234.28	-	234.28	29.10	14.2%
15	30%	3,285	392.99	451.14	-	451.14	58.15	14.8%
15	45%	4,928	580.91	668.13	-	668.13	87.22	15.0%
15	60%	6,570	687.34	794.49	-	794.49	107.15	15.6%
15	75%	8,213	790.09	916.78	-	916.78	126.69	16.0%
20	15%	2,190	267.74	306.53	-	306.53	38.79	14.5%
20	30%	4,380	518.23	595.76	-	595.76	77.53	15.0%
20	45%	6,570	687.34	794.49	-	794.49	107.15	15.6%
20	60%	8,760	824.30	957.49	-	957.49	133.19	16.2%
20	75%	10,950	961.26	1,120.49	-	1,120.49	159.23	16.6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 S Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
21	15%	2,300	370.37	394.90	-	394.90	24.53	6.6%
21	30%	4,599	530.29	585.56	-	585.56	55.27	10.4%
21	45%	6,899	618.33	690.17	-	690.17	71.84	11.6%
21	60%	9,198	706.34	794.73	-	794.73	88.39	12.5%
21	75%	11,498	794.38	899.33	-	899.33	104.95	13.2%
40	15%	4,380	689.78	723.82	-	723.82	34.04	4.9%
40	30%	8,760	994.46	1,087.08	-	1,087.08	92.62	9.3%
40	45%	13,140	1,162.13	1,286.29	-	1,286.29	124.16	10.7%
40	60%	17,520	1,329.80	1,485.49	-	1,485.49	155.69	11.7%
40	75%	21,900	1,497.46	1,684.69	-	1,684.69	187.23	12.5%
60	15%	6,570	1,026.04	1,070.11	-	1,070.11	44.07	4.3%
60	30%	13,140	1,483.07	1,615.00	-	1,615.00	131.93	8.9%
60	45%	19,710	1,734.57	1,913.80	-	1,913.80	179.23	10.3%
60	60%	26,280	1,986.07	2,212.60	-	2,212.60	226.53	11.4%
60	75%	32,850	2,237.57	2,511.41	-	2,511.41	273.84	12.2%
80	15%	8,760	1,362.31	1,416.39	-	1,416.39	54.08	4.0%
80	30%	17,520	1,971.68	2,142.91	-	2,142.91	171.23	8.7%
80	45%	26,280	2,307.01	2,541.32	-	2,541.32	234.31	10.2%
80	60%	35,040	2,642.34	2,939.72	-	2,939.72	297.38	11.3%
80	75%	43,800	2,977.67	3,338.13	-	3,338.13	360.46	12.1%
90	15%	9,855	1,530.44	1,589.53	-	1,589.53	59.09	3.9%
90	30%	19,710	2,215.98	2,406.87	-	2,406.87	190.89	8.6%
90	45%	29,565	2,593.23	2,855.07	-	2,855.07	261.84	10.1%
90	60%	39,420	2,970.48	3,303.28	-	3,303.28	332.80	11.2%
90	75%	49,275	3,347.73	3,751.49	-	3,751.49	403.76	12.1%
100	15%	10,950	1,698.57	1,762.67	-	1,762.67	64.10	3.8%
100	30%	21,900	2,460.28	2,670.83	-	2,670.83	210.55	8.6%
100	45%	32,850	2,879.45	3,168.83	-	3,168.83	289.38	10.0%
100	60%	43,800	3,298.61	3,666.84	-	3,666.84	368.23	11.2%
100	75%	54,750	3,717.78	4,164.84	-	4,164.84	447.06	12.0%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 S Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
21	15%	2,300	404.91	436.27	-	436.27	31.36	7.7%
21	30%	4,599	599.36	668.30	-	668.30	68.94	11.5%
21	45%	6,899	721.95	814.25	-	814.25	92.30	12.8%
21	60%	9,198	844.49	960.15	-	960.15	115.66	13.7%
21	75%	11,498	967.08	1,106.11	-	1,106.11	139.03	14.4%
40	15%	4,380	755.57	802.62	-	802.62	47.05	6.2%
40	30%	8,760	1,126.04	1,244.67	-	1,244.67	118.63	10.5%
40	45%	13,140	1,359.49	1,522.62	-	1,522.62	163.13	12.0%
40	60%	17,520	1,592.95	1,800.58	-	1,800.58	207.63	13.0%
40	75%	21,900	1,826.40	2,078.53	-	2,078.53	252.13	13.8%
60	15%	6,570	1,124.73	1,188.30	-	1,188.30	63.57	5.7%
60	30%	13,140	1,680.43	1,851.37	-	1,851.37	170.94	10.2%
60	45%	19,710	2,030.61	2,268.31	-	2,268.31	237.70	11.7%
60	60%	26,280	2,380.79	2,685.24	-	2,685.24	304.45	12.8%
60	75%	32,850	2,730.98	3,102.17	-	3,102.17	371.19	13.6%
80	15%	8,760	1,493.88	1,573.98	-	1,573.98	80.10	5.4%
80	30%	17,520	2,234.83	2,458.08	-	2,458.08	223.25	10.0%
80	45%	26,280	2,701.73	3,013.99	-	3,013.99	312.26	11.6%
80	60%	35,040	3,168.64	3,569.90	-	3,569.90	401.26	12.7%
80	75%	43,800	3,635.55	4,125.81	-	4,125.81	490.26	13.5%
90	15%	9,855	1,678.46	1,766.82	-	1,766.82	88.36	5.3%
90	30%	19,710	2,512.02	2,761.44	-	2,761.44	249.42	9.9%
90	45%	29,565	3,037.29	3,386.83	-	3,386.83	349.54	11.5%
90	60%	39,420	3,562.57	4,012.23	-	4,012.23	449.66	12.6%
90	75%	49,275	4,087.84	4,637.63	-	4,637.63	549.79	13.4%
100	15%	10,950	1,863.04	1,959.67	-	1,959.67	96.63	5.2%
100	30%	21,900	2,789.22	3,064.79	-	3,064.79	275.57	9.9%
100	45%	32,850	3,372.86	3,759.68	-	3,759.68	386.82	11.5%
100	60%	43,800	3,956.49	4,454.56	-	4,454.56	498.07	12.6%
100	75%	54,750	4,540.13	5,149.45	-	5,149.45	609.32	13.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 M Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
101	15%	11,060	1,728.23	1,812.39	-	1,812.39	84.16	4.9%
101	30%	22,119	2,497.51	2,672.76	-	2,672.76	175.25	7.0%
101	45%	33,179	2,920.89	3,151.13	-	3,151.13	230.24	7.9%
101	60%	44,238	3,344.23	3,629.45	-	3,629.45	285.22	8.5%
101	75%	55,298	3,767.61	4,107.82	-	4,107.82	340.21	9.0%
150	15%	16,425	2,357.61	2,471.35	-	2,471.35	113.74	4.8%
150	30%	32,850	3,500.17	3,749.19	-	3,749.19	249.02	7.1%
150	45%	49,275	4,128.92	4,459.61	-	4,459.61	330.69	8.0%
150	60%	65,700	4,757.67	5,170.02	-	5,170.02	412.35	8.7%
150	75%	82,125	5,386.42	5,880.44	-	5,880.44	494.02	9.2%
200	15%	21,900	2,999.87	3,143.81	-	3,143.81	143.94	4.8%
200	30%	43,800	4,523.28	4,847.59	-	4,847.59	324.31	7.2%
200	45%	65,700	5,361.62	5,794.81	-	5,794.81	433.19	8.1%
200	60%	87,600	6,199.95	6,742.04	-	6,742.04	542.09	8.7%
200	75%	109,500	7,038.28	7,689.26	-	7,689.26	650.98	9.2%
300	15%	32,850	4,284.39	4,488.71	-	4,488.71	204.32	4.8%
300	30%	65,700	6,569.52	7,044.39	-	7,044.39	474.87	7.2%
300	45%	98,550	7,827.01	8,465.22	-	8,465.22	638.21	8.2%
300	60%	131,400	9,084.51	9,886.06	-	9,886.06	801.55	8.8%
300	75%	164,250	10,342.01	11,306.89	-	11,306.89	964.88	9.3%
350	15%	38,325	4,926.65	5,161.17	-	5,161.17	234.52	4.8%
350	30%	76,650	7,592.63	8,142.78	-	8,142.78	550.15	7.2%
350	45%	114,975	9,059.71	9,800.43	-	9,800.43	740.72	8.2%
350	60%	153,300	10,526.79	11,458.07	-	11,458.07	931.28	8.8%
350	75%	191,625	11,993.88	13,115.71	-	13,115.71	1,121.83	9.4%
400	15%	43,800	5,568.91	5,833.62	-	5,833.62	264.71	4.8%
400	30%	87,600	8,615.75	9,241.18	-	9,241.18	625.43	7.3%
400	45%	131,400	10,292.41	11,135.63	-	11,135.63	843.22	8.2%
400	60%	175,200	11,969.08	13,030.08	-	13,030.08	1,061.00	8.9%
400	75%	219,000	13,645.74	14,924.53	-	14,924.53	1,278.79	9.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 M Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates	Amount ($)	%
						(E) + (F)	(G) - (D)	(H) / (D)
101	15%	11,060	1,894.35	1,995.80	-	1,995.80	101.45	5.4%
101	30%	22,119	2,829.74	3,039.56	-	3,039.56	209.82	7.4%
101	45%	33,179	3,419.24	3,701.33	-	3,701.33	282.09	8.3%
101	60%	44,238	4,008.68	4,363.05	-	4,363.05	354.37	8.8%
101	75%	55,298	4,598.18	5,024.83	-	5,024.83	426.65	9.3%
150	15%	16,425	2,604.31	2,743.73	-	2,743.73	139.42	5.4%
150	30%	32,850	3,993.58	4,293.94	-	4,293.94	300.36	7.5%
150	45%	49,275	4,869.03	5,276.73	-	5,276.73	407.70	8.4%
150	60%	65,700	5,744.48	6,259.52	-	6,259.52	515.04	9.0%
150	75%	82,125	6,619.93	7,242.32	-	7,242.32	622.39	9.4%
200	15%	21,900	3,328.81	3,506.97	-	3,506.97	178.16	5.4%
200	30%	43,800	5,181.16	5,573.92	-	5,573.92	392.76	7.6%
200	45%	65,700	6,348.43	6,884.31	-	6,884.31	535.88	8.4%
200	60%	87,600	7,515.70	8,194.70	-	8,194.70	679.00	9.0%
200	75%	109,500	8,682.97	9,505.09	-	9,505.09	822.12	9.5%
300	15%	32,850	4,777.80	5,033.46	-	5,033.46	255.66	5.4%
300	30%	65,700	7,556.33	8,133.88	-	8,133.88	577.55	7.6%
300	45%	98,550	9,307.24	10,099.47	-	10,099.47	792.23	8.5%
300	60%	131,400	11,058.14	12,065.06	-	12,065.06	1,006.92	9.1%
300	75%	164,250	12,809.05	14,030.64	-	14,030.64	1,221.59	9.5%
350	15%	38,325	5,502.29	5,796.71	-	5,796.71	294.42	5.4%
350	30%	76,650	8,743.92	9,413.87	-	9,413.87	669.95	7.7%
350	45%	114,975	10,786.64	11,707.05	-	11,707.05	920.41	8.5%
350	60%	153,300	12,829.36	14,000.23	-	14,000.23	1,170.87	9.1%
350	75%	191,625	14,872.08	16,293.42	-	16,293.42	1,421.34	9.6%
400	15%	43,800	6,226.79	6,559.95	-	6,559.95	333.16	5.4%
400	30%	87,600	9,931.50	10,693.85	-	10,693.85	762.35	7.7%
400	45%	131,400	12,266.04	13,314.63	-	13,314.63	1,048.59	8.5%
400	60%	175,200	14,600.58	15,935.41	-	15,935.41	1,334.83	9.1%
400	75%	219,000	16,935.12	18,556.19	-	18,556.19	1,621.07	9.6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 L Winter (November-April)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
401	15%	43,910	5,581.80	5,837.82	-	5,837.82	256.02	4.6%
401	30%	87,819	8,636.21	9,192.94	-	9,192.94	556.73	6.4%
401	45%	131,729	10,317.09	11,130.69	-	11,130.69	813.60	7.9%
401	60%	175,638	11,997.92	13,068.40	-	13,068.40	1,070.48	8.9%
401	75%	219,548	13,678.80	15,006.16	-	15,006.16	1,327.36	9.7%
600	15%	65,700	8,137.96	8,501.89	-	8,501.89	363.93	4.5%
600	30%	131,400	12,708.21	13,522.07	-	13,522.07	813.86	6.4%
600	45%	197,100	15,223.21	16,421.42	-	16,421.42	1,198.21	7.9%
600	60%	262,800	17,738.20	19,320.77	-	19,320.77	1,582.57	8.9%
600	75%	328,500	20,253.20	22,220.12	-	22,220.12	1,966.92	9.7%
800	15%	87,600	10,707.01	11,179.38	-	11,179.38	472.37	4.4%
800	30%	175,200	16,800.68	17,872.96	-	17,872.96	1,072.28	6.4%
800	45%	262,800	20,154.00	21,738.76	-	21,738.76	1,584.76	7.9%
800	60%	350,400	23,507.33	25,604.56	-	25,604.56	2,097.23	8.9%
800	75%	438,000	26,860.66	29,470.36	-	29,470.36	2,609.70	9.7%
1,000	15%	109,500	13,276.06	13,856.88	-	13,856.88	580.82	4.4%
1,000	30%	219,000	20,893.14	22,223.85	-	22,223.85	1,330.71	6.4%
1,000	45%	328,500	25,084.80	27,056.10	-	27,056.10	1,971.30	7.9%
1,000	60%	438,000	29,276.46	31,888.35	-	31,888.35	2,611.89	8.9%
1,000	75%	547,500	33,468.12	36,720.60	-	36,720.60	3,252.48	9.7%
1,500	15%	164,250	19,698.67	20,550.61	-	20,550.61	851.94	4.3%
1,500	30%	328,500	31,124.30	33,101.07	-	33,101.07	1,976.77	6.4%
1,500	45%	492,750	37,411.79	40,349.45	-	40,349.45	2,937.66	7.9%
1,500	60%	657,000	43,699.28	47,597.83	-	47,597.83	3,898.55	8.9%
1,500	75%	821,250	49,986.77	54,846.20	-	54,846.20	4,859.43	9.7%
3,000	15%	328,500	38,966.53	40,631.82	-	40,631.82	1,665.29	4.3%
3,000	30%	657,000	61,817.78	65,732.74	-	65,732.74	3,914.96	6.3%
3,000	45%	985,500	74,392.76	80,229.50	-	80,229.50	5,836.74	7.8%
3,000	60%	1,314,000	86,967.74	94,726.25	-	94,726.25	7,758.51	8.9%
3,000	75%	1,642,500	99,542.72	109,223.00	-	109,223.00	9,680.28	9.7%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 L Summer (May-October)

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates	Amount ($)	%
						(E) + (F)	(G) - (D)	(H) / (D)
401	15%	43,910	6,241.33	6,518.44	-	6,518.44	277.11	4.4%
401	30%	87,819	9,955.25	10,554.15	-	10,554.15	598.90	6.0%
401	45%	131,729	12,295.65	13,172.52	-	13,172.52	876.87	7.1%
401	60%	175,638	14,636.00	15,790.82	-	15,790.82	1,154.82	7.9%
401	75%	219,548	16,976.41	18,409.19	-	18,409.19	1,432.78	8.4%
600	15%	65,700	9,124.78	9,520.25	-	9,520.25	395.47	4.3%
600	30%	131,400	14,681.84	15,558.80	-	15,558.80	876.96	6.0%
600	45%	197,100	18,183.65	19,476.51	-	19,476.51	1,292.86	7.1%
600	60%	262,800	21,685.46	23,394.22	-	23,394.22	1,708.76	7.9%
600	75%	328,500	25,187.27	27,311.93	-	27,311.93	2,124.66	8.4%
800	15%	87,600	12,022.76	12,537.20	-	12,537.20	514.44	4.3%
800	30%	175,200	19,432.18	20,588.59	-	20,588.59	1,156.41	6.0%
800	45%	262,800	24,101.26	25,812.21	-	25,812.21	1,710.95	7.1%
800	60%	350,400	28,770.34	31,035.83	-	31,035.83	2,265.49	7.9%
800	75%	438,000	33,439.42	36,259.44	-	36,259.44	2,820.02	8.4%
1,000	15%	109,500	14,920.75	15,554.15	-	15,554.15	633.40	4.2%
1,000	30%	219,000	24,182.52	25,618.39	-	25,618.39	1,435.87	5.9%
1,000	45%	328,500	30,018.87	32,147.91	-	32,147.91	2,129.04	7.1%
1,000	60%	438,000	35,855.22	38,677.43	-	38,677.43	2,822.21	7.9%
1,000	75%	547,500	41,691.57	45,206.95	-	45,206.95	3,515.38	8.4%
1,500	15%	164,250	22,165.71	23,096.52	-	23,096.52	930.81	4.2%
1,500	30%	328,500	36,058.37	38,192.88	-	38,192.88	2,134.51	5.9%
1,500	45%	492,750	44,812.90	47,987.16	-	47,987.16	3,174.26	7.1%
1,500	60%	657,000	53,567.42	57,781.44	-	57,781.44	4,214.02	7.9%
1,500	75%	821,250	62,321.95	67,575.73	-	67,575.73	5,253.78	8.4%
3,000	15%	328,500	43,900.60	45,723.63	-	45,723.63	1,823.03	4.2%
3,000	30%	657,000	71,685.92	75,916.36	-	75,916.36	4,230.44	5.9%
3,000	45%	985,500	89,194.97	95,504.92	-	95,504.92	6,309.95	7.1%
3,000	60%	1,314,000	106,704.02	115,093.48	-	115,093.48	8,389.46	7.9%
3,000	75%	1,642,500	124,213.07	134,682.05	-	134,682.05	10,468.98	8.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU XS Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
5	7.5	15%	821	102.62	115.61	-	115.61	12.99	12.7%
5	7.5	30%	1,643	187.11	213.09	-	213.09	25.98	13.9%
5	7.5	45%	2,464	271.49	310.44	-	310.44	38.95	14.3%
5	7.5	60%	3,285	355.88	407.79	-	407.79	51.91	14.6%
5	7.5	75%	4,106	440.26	505.15	-	505.15	64.89	14.7%
10	12	15%	1,314	153.29	174.07	-	174.07	20.78	13.6%
10	12	30%	2,628	288.35	329.89	-	329.89	41.54	14.4%
10	12	45%	3,942	423.40	485.70	-	485.70	62.30	14.7%
10	12	60%	5,256	558.46	641.51	-	641.51	83.05	14.9%
10	12	75%	6,570	693.51	797.33	-	797.33	103.82	15.0%
15	20	15%	2,190	243.33	277.95	-	277.95	34.62	14.2%
15	20	30%	4,380	468.42	537.64	-	537.64	69.22	14.8%
15	20	45%	6,570	693.51	797.33	-	797.33	103.82	15.0%
15	20	60%	8,760	852.20	976.80	-	976.80	124.60	14.6%
15	20	75%	10,950	981.22	1,120.42	-	1,120.42	139.20	14.2%
20	25	15%	2,738	299.66	342.93	-	342.93	43.27	14.4%
20	25	30%	5,475	580.97	667.48	-	667.48	86.51	14.9%
20	25	45%	8,213	819.98	940.92	-	940.92	120.94	14.7%
20	25	60%	10,950	981.22	1,120.42	-	1,120.42	139.20	14.2%
20	25	75%	13,688	1,142.52	1,299.98	-	1,299.98	157.46	13.8%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU XS Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
5	7.5	15%	821	114.80	130.21	-	130.21	15.41	13.4%
5	7.5	30%	1,643	211.47	242.30	-	242.30	30.83	14.6%
5	7.5	45%	2,464	308.03	354.26	-	354.26	46.23	15.0%
5	7.5	60%	3,285	404.58	466.21	-	466.21	61.63	15.2%
5	7.5	75%	4,106	501.14	578.16	-	578.16	77.02	15.4%
10	12	15%	1,314	172.78	197.44	-	197.44	24.66	14.3%
10	12	30%	2,628	327.31	376.62	-	376.62	49.31	15.1%
10	12	45%	3,942	481.85	555.80	-	555.80	73.95	15.3%
10	12	60%	5,256	636.39	734.98	-	734.98	98.59	15.5%
10	12	75%	6,570	790.93	914.16	-	914.16	123.23	15.6%
15	20	15%	2,190	275.80	316.89	-	316.89	41.09	14.9%
15	20	30%	4,380	533.36	615.53	-	615.53	82.17	15.4%
15	20	45%	6,570	790.93	914.16	-	914.16	123.23	15.6%
15	20	60%	8,760	977.91	1,127.56	-	1,127.56	149.65	15.3%
15	20	75%	10,950	1,133.35	1,302.88	-	1,302.88	169.53	15.0%
20	25	15%	2,738	340.25	391.62	-	391.62	51.37	15.1%
20	25	30%	5,475	662.14	764.84	-	764.84	102.70	15.5%
20	25	45%	8,213	939.08	1,083.77	-	1,083.77	144.69	15.4%
20	25	60%	10,950	1,133.35	1,302.88	-	1,302.88	169.53	15.0%
20	25	75%	13,688	1,327.69	1,522.06	-	1,522.06	194.37	14.6%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU S Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
21	30	15%	3,285	550.78	602.34	-	602.34	51.56	9.4%
21	30	30%	6,570	680.26	755.56	-	755.56	75.30	11.1%
21	30	45%	9,855	809.75	908.79	-	908.79	99.04	12.2%
21	30	60%	13,140	939.24	1,062.01	-	1,062.01	122.77	13.1%
21	30	75%	16,425	1,068.72	1,215.23	-	1,215.23	146.51	13.7%
40	50	15%	5,475	967.80	1,043.86	-	1,043.86	76.06	7.9%
40	50	30%	10,950	1,183.61	1,299.23	-	1,299.23	115.62	9.8%
40	50	45%	16,425	1,399.42	1,554.60	-	1,554.60	155.18	11.1%
40	50	60%	21,900	1,615.24	1,809.97	-	1,809.97	194.73	12.1%
40	50	75%	27,375	1,831.05	2,065.34	-	2,065.34	234.29	12.8%
60	70	15%	7,665	1,397.23	1,497.66	-	1,497.66	100.43	7.2%
60	70	30%	15,330	1,699.36	1,855.18	-	1,855.18	155.82	9.2%
60	70	45%	22,995	2,001.50	2,212.70	-	2,212.70	211.20	10.6%
60	70	60%	30,660	2,303.63	2,570.22	-	2,570.22	266.59	11.6%
60	70	75%	38,325	2,605.77	2,927.73	-	2,927.73	321.96	12.4%
80	100	15%	10,950	1,917.36	2,055.50	-	2,055.50	138.14	7.2%
80	100	30%	21,900	2,348.99	2,566.24	-	2,566.24	217.25	9.2%
80	100	45%	32,850	2,780.61	3,076.98	-	3,076.98	296.37	10.7%
80	100	60%	43,800	3,212.23	3,587.72	-	3,587.72	375.49	11.7%
80	100	75%	54,750	3,643.85	4,098.46	-	4,098.46	454.61	12.5%
90	110	15%	12,045	2,111.00	2,258.86	-	2,258.86	147.86	7.0%
90	110	30%	24,090	2,585.79	2,820.68	-	2,820.68	234.89	9.1%
90	110	45%	36,135	3,060.57	3,382.49	-	3,382.49	321.92	10.5%
90	110	60%	48,180	3,535.36	3,944.30	-	3,944.30	408.94	11.6%
90	110	75%	60,225	4,010.14	4,506.12	-	4,506.12	495.98	12.4%
100	120	15%	13,140	2,304.65	2,462.23	-	2,462.23	157.58	6.8%
100	120	30%	26,280	2,822.59	3,075.11	-	3,075.11	252.52	8.9%
100	120	45%	39,420	3,340.54	3,688.00	-	3,688.00	347.46	10.4%
100	120	60%	52,560	3,858.49	4,300.89	-	4,300.89	442.40	11.5%
100	120	75%	65,700	4,376.44	4,913.78	-	4,913.78	537.34	12.3%

E-32TOU On-Peak Split: 31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU S Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
21	30	15%	3,285	599.26	655.97	-	655.97	56.71	9.5%
21	30	30%	6,570	777.24	862.81	-	862.81	85.57	11.0%
21	30	45%	9,855	955.21	1,069.66	-	1,069.66	114.45	12.0%
21	30	60%	13,140	1,133.18	1,276.51	-	1,276.51	143.33	12.6%
21	30	75%	16,425	1,311.16	1,483.35	-	1,483.35	172.19	13.1%
40	50	15%	5,475	1,048.61	1,133.23	-	1,133.23	84.62	8.1%
40	50	30%	10,950	1,345.23	1,477.98	-	1,477.98	132.75	9.9%
40	50	45%	16,425	1,641.86	1,822.72	-	1,822.72	180.86	11.0%
40	50	60%	21,900	1,938.48	2,167.47	-	2,167.47	228.99	11.8%
40	50	75%	27,375	2,235.10	2,512.21	-	2,512.21	277.11	12.4%
60	70	15%	7,665	1,510.36	1,622.79	-	1,622.79	112.43	7.4%
60	70	30%	15,330	1,925.63	2,105.43	-	2,105.43	179.80	9.3%
60	70	45%	22,995	2,340.90	2,588.07	-	2,588.07	247.17	10.6%
60	70	60%	30,660	2,756.18	3,070.71	-	3,070.71	314.53	11.4%
60	70	75%	38,325	3,171.45	3,553.35	-	3,553.35	381.90	12.0%
80	100	15%	10,950	2,078.98	2,234.25	-	2,234.25	155.27	7.5%
80	100	30%	21,900	2,672.23	2,923.74	-	2,923.74	251.51	9.4%
80	100	45%	32,850	3,265.47	3,613.22	-	3,613.22	347.75	10.6%
80	100	60%	43,800	3,858.72	4,302.71	-	4,302.71	443.99	11.5%
80	100	75%	54,750	4,451.96	4,992.20	-	4,992.20	540.24	12.1%
90	110	15%	12,045	2,288.79	2,455.49	-	2,455.49	166.70	7.3%
90	110	30%	24,090	2,941.36	3,213.92	-	3,213.92	272.56	9.3%
90	110	45%	36,135	3,593.93	3,972.36	-	3,972.36	378.43	10.5%
90	110	60%	48,180	4,246.50	4,730.80	-	4,730.80	484.30	11.4%
90	110	75%	60,225	4,899.07	5,489.23	-	5,489.23	590.16	12.0%
100	120	15%	13,140	2,498.59	2,676.73	-	2,676.73	178.14	7.1%
100	120	30%	26,280	3,210.49	3,504.11	-	3,504.11	293.62	9.1%
100	120	45%	39,420	3,922.38	4,331.50	-	4,331.50	409.12	10.4%
100	120	60%	52,560	4,634.27	5,158.88	-	5,158.88	524.61	11.3%
100	120	75%	65,700	5,346.17	5,986.27	-	5,986.27	640.10	12.0%
				31%					

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU M Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
101	120	15%	13,140	2,313.07	2,561.75	-	2,561.75	248.68	10.8%
101	120	30%	26,280	2,831.01	3,174.64	-	3,174.64	343.63	12.1%
101	120	45%	39,420	3,348.96	3,787.52	-	3,787.52	438.56	13.1%
101	120	60%	52,560	3,866.91	4,400.41	-	4,400.41	533.50	13.8%
101	120	75%	65,700	4,384.86	5,013.30	-	5,013.30	628.44	14.3%
150	170	15%	18,615	3,073.86	3,338.12	-	3,338.12	264.26	8.6%
150	170	30%	37,230	3,807.62	4,206.38	-	4,206.38	398.76	10.5%
150	170	45%	55,845	4,541.38	5,074.63	-	5,074.63	533.25	11.7%
150	170	60%	74,460	5,275.13	5,942.89	-	5,942.89	667.76	12.7%
150	170	75%	93,075	6,008.89	6,811.15	-	6,811.15	802.26	13.4%
200	220	15%	24,090	3,843.07	4,122.15	-	4,122.15	279.08	7.3%
200	220	30%	48,180	4,792.64	5,245.77	-	5,245.77	453.13	9.5%
200	220	45%	72,270	5,742.21	6,369.40	-	6,369.40	627.19	10.9%
200	220	60%	96,360	6,691.78	7,493.02	-	7,493.02	801.24	12.0%
200	220	75%	120,450	7,641.35	8,616.65	-	8,616.65	975.30	12.8%
300	320	15%	35,040	5,381.49	5,690.19	-	5,690.19	308.70	5.7%
300	320	30%	70,080	6,762.69	7,324.56	-	7,324.56	561.87	8.3%
300	320	45%	105,120	8,143.88	8,958.92	-	8,958.92	815.04	10.0%
300	320	60%	140,160	9,525.07	10,593.29	-	10,593.29	1,068.22	11.2%
300	320	75%	175,200	10,906.26	12,227.66	-	12,227.66	1,321.40	12.1%
350	370	15%	40,515	6,150.70	6,474.22	-	6,474.22	323.52	5.3%
350	370	30%	81,030	7,747.71	8,363.95	-	8,363.95	616.24	8.0%
350	370	45%	121,545	9,344.71	10,253.69	-	10,253.69	908.98	9.7%
350	370	60%	162,060	10,941.72	12,143.42	-	12,143.42	1,201.70	11.0%
350	370	75%	202,575	12,538.72	14,033.16	-	14,033.16	1,494.44	11.9%
400	420	15%	45,990	6,919.92	7,258.24	-	7,258.24	338.32	4.9%
400	420	30%	91,980	8,732.73	9,403.35	-	9,403.35	670.62	7.7%
400	420	45%	137,970	10,545.55	11,548.45	-	11,548.45	1,002.90	9.5%
400	420	60%	183,960	12,358.36	13,693.56	-	13,693.56	1,335.20	10.8%
400	420	75%	229,950	14,171.18	15,838.66	-	15,838.66	1,667.48	11.8%
				31%					

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU M Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
101	120	15%	13,140	2,507.01	2,793.71	-	2,793.71	286.70	11.4%
101	120	30%	26,280	3,218.91	3,638.55	-	3,638.55	419.64	13.0%
101	120	45%	39,420	3,930.80	4,483.40	-	4,483.40	552.60	14.1%
101	120	60%	52,560	4,642.69	5,328.25	-	5,328.25	685.56	14.8%
101	120	75%	65,700	5,354.59	6,173.09	-	6,173.09	818.50	15.3%
150	170	15%	18,615	3,348.62	3,666.73	-	3,666.73	318.11	9.5%
150	170	30%	37,230	4,357.13	4,863.60	-	4,863.60	506.47	11.6%
150	170	45%	55,845	5,365.65	6,060.46	-	6,060.46	694.81	12.9%
150	170	60%	74,460	6,374.16	7,257.33	-	7,257.33	883.17	13.9%
150	170	75%	93,075	7,382.68	8,454.19	-	8,454.19	1,071.51	14.5%
200	220	15%	24,090	4,198.64	4,547.40	-	4,547.40	348.76	8.3%
200	220	30%	48,180	5,503.78	6,096.29	-	6,096.29	592.51	10.8%
200	220	45%	72,270	6,808.92	7,645.18	-	7,645.18	836.26	12.3%
200	220	60%	96,360	8,114.05	9,194.06	-	9,194.06	1,080.01	13.3%
200	220	75%	120,450	9,419.19	10,742.95	-	10,742.95	1,323.76	14.1%
300	320	15%	35,040	5,898.68	6,308.75	-	6,308.75	410.07	7.0%
300	320	30%	70,080	7,797.07	8,561.68	-	8,561.68	764.61	9.8%
300	320	45%	105,120	9,695.45	10,814.60	-	10,814.60	1,119.15	11.5%
300	320	60%	140,160	11,593.83	13,067.53	-	13,067.53	1,473.70	12.7%
300	320	75%	175,200	13,492.22	15,320.45	-	15,320.45	1,828.23	13.6%
350	370	15%	40,515	6,748.71	7,189.43	-	7,189.43	440.72	6.5%
350	370	30%	81,030	8,943.71	9,794.37	-	9,794.37	850.66	9.5%
350	370	45%	121,545	11,138.72	12,399.31	-	12,399.31	1,260.59	11.3%
350	370	60%	162,060	13,333.72	15,004.26	-	15,004.26	1,670.54	12.5%
350	370	75%	202,575	15,528.73	17,609.20	-	17,609.20	2,080.47	13.4%
400	420	15%	45,990	7,598.73	8,070.10	-	8,070.10	471.37	6.2%
400	420	30%	91,980	10,090.36	11,027.06	-	11,027.06	936.70	9.3%
400	420	45%	137,970	12,581.98	13,984.03	-	13,984.03	1,402.05	11.1%
400	420	60%	183,960	15,073.61	16,940.99	-	16,940.99	1,867.38	12.4%
400	420	75%	229,950	17,565.24	19,897.95	-	19,897.95	2,332.71	13.3%

31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU L Winter (November-April)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates	Amount ($)	%
							(F) + (G)	(H) - (E)	(I) / (E)
401	441	15%	48,290	7,074.60	7,544.41	-	7,544.41	469.81	6.6%
401	441	30%	96,579	8,978.04	9,792.39	-	9,792.39	814.35	9.1%
401	441	45%	144,869	10,881.52	12,040.42	-	12,040.42	1,158.90	10.7%
401	441	60%	193,158	12,784.95	14,288.41	-	14,288.41	1,503.46	11.8%
401	441	75%	241,448	14,688.43	16,536.44	-	16,536.44	1,848.01	12.6%
600	640	15%	70,080	10,136.05	10,722.82	-	10,722.82	586.77	5.8%
600	640	30%	140,160	12,898.43	13,985.23	-	13,985.23	1,086.80	8.4%
600	640	45%	210,240	15,660.82	17,247.65	-	17,247.65	1,586.83	10.1%
600	640	60%	280,320	18,423.20	20,510.06	-	20,510.06	2,086.86	11.3%
600	640	75%	350,400	21,185.59	23,772.48	-	23,772.48	2,586.89	12.2%
800	860	15%	94,170	13,352.18	14,078.58	-	14,078.58	726.40	5.4%
800	860	30%	188,340	17,064.13	18,462.45	-	18,462.45	1,398.32	8.2%
800	860	45%	282,510	20,776.09	22,846.32	-	22,846.32	2,070.23	10.0%
800	860	60%	376,680	24,488.04	27,230.19	-	27,230.19	2,742.15	11.2%
800	860	75%	470,850	28,200.00	31,614.06	-	31,614.06	3,414.06	12.1%
1,000	1,200	15%	131,400	17,404.01	18,402.48	-	18,402.48	998.47	5.7%
1,000	1,200	30%	262,800	22,583.49	24,519.51	-	24,519.51	1,936.02	8.6%
1,000	1,200	45%	394,200	27,762.96	30,636.54	-	30,636.54	2,873.58	10.4%
1,000	1,200	60%	525,600	32,942.43	36,753.57	-	36,753.57	3,811.14	11.6%
1,000	1,200	75%	657,000	38,121.90	42,870.59	-	42,870.59	4,748.69	12.5%
1,500	1,700	15%	186,150	25,096.13	26,388.50	-	26,388.50	1,292.37	5.1%
1,500	1,700	30%	372,300	32,433.71	35,054.29	-	35,054.29	2,620.58	8.1%
1,500	1,700	45%	558,450	39,771.30	43,720.08	-	43,720.08	3,948.78	9.9%
1,500	1,700	60%	744,600	47,108.88	52,385.87	-	52,385.87	5,276.99	11.2%
1,500	1,700	75%	930,750	54,446.47	61,051.66	-	61,051.66	6,605.19	12.1%
3,000	3,200	15%	350,400	48,172.47	50,346.55	-	50,346.55	2,174.08	4.5%
3,000	3,200	30%	700,800	61,984.39	66,658.63	-	66,658.63	4,674.24	7.5%
3,000	3,200	45%	1,051,200	75,796.32	82,970.70	-	82,970.70	7,174.38	9.5%
3,000	3,200	60%	1,401,600	89,608.25	99,282.77	-	99,282.77	9,674.52	10.8%
3,000	3,200	75%	1,752,000	103,420.18	115,594.85	-	115,594.85	12,174.67	11.8%
				31%					

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-32 TOU L Summer (May-October)

Customer Bills at Varying Consumption Levels at 31% on-peak
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
401	441	15%	48,290	7,787.36	8,394.80	-	8,394.80	607.44	7.8%
401	441	30%	96,579	10,403.55	11,493.17	-	11,493.17	1,089.62	10.5%
401	441	45%	144,869	13,019.78	14,591.60	-	14,591.60	1,571.82	12.1%
401	441	60%	193,158	15,635.96	17,689.96	-	17,689.96	2,054.00	13.1%
401	441	75%	241,448	18,252.20	20,788.39	-	20,788.39	2,536.19	13.9%
600	640	15%	70,080	11,170.43	11,956.94	-	11,956.94	786.51	7.0%
600	640	30%	140,160	14,967.19	16,453.48	-	16,453.48	1,486.29	9.9%
600	640	45%	210,240	18,763.96	20,950.02	-	20,950.02	2,186.06	11.7%
600	640	60%	280,320	22,560.72	25,446.56	-	25,446.56	2,885.84	12.8%
600	640	75%	350,400	26,357.49	29,943.10	-	29,943.10	3,585.61	13.6%
800	860	15%	94,170	14,742.12	15,736.94	-	15,736.94	994.82	6.7%
800	860	30%	188,340	19,844.03	21,779.16	-	21,779.16	1,935.13	9.8%
800	860	45%	282,510	24,945.93	27,821.38	-	27,821.38	2,875.45	11.5%
800	860	60%	376,680	30,047.84	33,863.61	-	33,863.61	3,815.77	12.7%
800	860	75%	470,850	35,149.74	39,905.83	-	39,905.83	4,756.09	13.5%
1,000	1,200	15%	131,400	19,343.48	20,716.47	-	20,716.47	1,372.99	7.1%
1,000	1,200	30%	262,800	26,462.41	29,147.48	-	29,147.48	2,685.07	10.1%
1,000	1,200	45%	394,200	33,581.35	37,578.48	-	37,578.48	3,997.13	11.9%
1,000	1,200	60%	525,600	40,700.29	46,009.49	-	46,009.49	5,309.20	13.0%
1,000	1,200	75%	657,000	47,819.22	54,440.50	-	54,440.50	6,621.28	13.8%
1,500	1,700	15%	186,150	27,843.70	29,666.64	-	29,666.64	1,822.94	6.5%
1,500	1,700	30%	372,300	37,928.86	41,610.57	-	41,610.57	3,681.71	9.7%
1,500	1,700	45%	558,450	48,014.02	53,554.50	-	53,554.50	5,540.48	11.5%
1,500	1,700	60%	744,600	58,099.18	65,498.43	-	65,498.43	7,399.25	12.7%
1,500	1,700	75%	930,750	68,184.34	77,442.36	-	77,442.36	9,258.02	13.6%
3,000	3,200	15%	350,400	53,344.37	56,517.17	-	56,517.17	3,172.80	5.9%
3,000	3,200	30%	700,800	72,328.20	78,999.86	-	78,999.86	6,671.66	9.2%
3,000	3,200	45%	1,051,200	91,312.03	101,482.55	-	101,482.55	10,170.52	11.1%
3,000	3,200	60%	1,401,600	110,295.86	123,965.25	-	123,965.25	13,669.39	12.4%
3,000	3,200	75%	1,752,000	129,279.70	146,447.94	-	146,447.94	17,168.24	13.3%

31%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-34

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
3,000	20%	438,000	62,196.72	69,793.45	-	69,793.45	7,596.73	12.2%
3,000	30%	657,000	70,332.57	78,922.52	-	78,922.52	8,589.95	12.2%
3,000	40%	876,000	78,468.42	88,051.60	-	88,051.60	9,583.18	12.2%
3,000	50%	1,095,000	86,604.27	97,180.67	-	97,180.67	10,576.40	12.2%
3,000	75%	1,642,500	106,943.90	120,003.36	-	120,003.36	13,059.46	12.2%
3,500	20%	511,000	72,557.17	81,418.70	-	81,418.70	8,861.53	12.2%
3,500	30%	766,500	82,049.00	92,069.29	-	92,069.29	10,020.29	12.2%
3,500	40%	1,022,000	91,540.82	102,719.88	-	102,719.88	11,179.06	12.2%
3,500	50%	1,277,500	101,032.65	113,370.46	-	113,370.46	12,337.81	12.2%
3,500	75%	1,916,250	124,762.21	139,996.93	-	139,996.93	15,234.72	12.2%
4,000	20%	584,000	82,917.62	93,043.96	-	93,043.96	10,126.34	12.2%
4,000	30%	876,000	93,765.42	105,216.06	-	105,216.06	11,450.64	12.2%
4,000	40%	1,168,000	104,613.22	117,388.15	-	117,388.15	12,774.93	12.2%
4,000	50%	1,460,000	115,461.02	129,560.25	-	129,560.25	14,099.23	12.2%
4,000	75%	2,190,000	142,580.52	159,990.50	-	159,990.50	17,409.98	12.2%
4,500	20%	657,000	93,278.07	104,669.21	-	104,669.21	11,391.14	12.2%
4,500	30%	985,500	105,481.85	118,362.82	-	118,362.82	12,880.97	12.2%
4,500	40%	1,314,000	117,685.62	132,056.43	-	132,056.43	14,370.81	12.2%
4,500	50%	1,642,500	129,889.40	145,750.05	-	145,750.05	15,860.65	12.2%
4,500	75%	2,463,750	160,398.83	179,984.08	-	179,984.08	19,585.25	12.2%
5,000	20%	730,000	103,638.52	116,294.46	-	116,294.46	12,655.94	12.2%
5,000	30%	1,095,000	117,198.27	131,509.59	-	131,509.59	14,311.32	12.2%
5,000	40%	1,460,000	130,758.02	146,724.71	-	146,724.71	15,966.69	12.2%
5,000	50%	1,825,000	144,317.77	161,939.84	-	161,939.84	17,622.07	12.2%
5,000	75%	2,737,500	178,217.15	199,977.65	-	199,977.65	21,760.50	12.2%
6,000	20%	876,000	124,359.42	139,544.97	-	139,544.97	15,185.55	12.2%
6,000	30%	1,314,000	140,631.12	157,803.12	-	157,803.12	17,172.00	12.2%
6,000	40%	1,752,000	156,902.82	176,061.27	-	176,061.27	19,158.45	12.2%
6,000	50%	2,190,000	173,174.52	194,319.42	-	194,319.42	21,144.90	12.2%
6,000	75%	3,285,000	213,853.77	239,964.79	-	239,964.79	26,111.02	12.2%
7,000	20%	1,022,000	145,080.32	162,795.48	-	162,795.48	17,715.16	12.2%
7,000	30%	1,533,000	164,063.97	184,096.65	-	184,096.65	20,032.68	12.2%
7,000	50%	2,555,000	202,031.27	226,699.00	-	226,699.00	24,667.73	12.2%
7,000	75%	3,832,500	249,490.40	279,951.94	-	279,951.94	30,461.54	12.2%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-35

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
3,000	4,000	20%	438,000	64,609.82	72,254.46	-	72,254.46	7,644.64	11.8%
3,000	4,000	30%	657,000	72,104.22	80,635.14	-	80,635.14	8,530.92	11.8%
3,000	4,000	40%	876,000	79,598.62	89,015.83	-	89,015.83	9,417.21	11.8%
3,000	4,000	50%	1,095,000	87,093.02	97,396.52	-	97,396.52	10,303.50	11.8%
3,000	4,000	75%	1,642,500	105,829.01	118,348.23	-	118,348.23	12,519.22	11.8%
3,500	4,500	20%	511,000	74,970.45	83,840.34	-	83,840.34	8,869.89	11.8%
3,500	4,500	30%	766,500	83,713.92	93,617.81	-	93,617.81	9,903.89	11.8%
3,500	4,500	40%	1,022,000	92,457.38	103,395.28	-	103,395.28	10,937.90	11.8%
3,500	4,500	50%	1,277,500	101,200.85	113,172.74	-	113,172.74	11,971.89	11.8%
3,500	4,500	75%	1,916,250	123,059.51	137,616.41	-	137,616.41	14,556.90	11.8%
4,000	5,000	20%	584,000	85,331.08	95,426.22	-	95,426.22	10,095.14	11.8%
4,000	5,000	30%	876,000	95,323.62	106,600.47	-	106,600.47	11,276.85	11.8%
4,000	5,000	40%	1,168,000	105,316.15	117,774.72	-	117,774.72	12,458.57	11.8%
4,000	5,000	50%	1,460,000	115,308.68	128,948.97	-	128,948.97	13,640.29	11.8%
4,000	5,000	75%	2,190,000	140,290.01	156,884.59	-	156,884.59	16,594.58	11.8%
4,500	6,000	20%	657,000	96,897.72	108,360.72	-	108,360.72	11,463.00	11.8%
4,500	6,000	30%	985,500	108,139.32	120,931.75	-	120,931.75	12,792.43	11.8%
4,500	6,000	40%	1,314,000	119,380.91	133,502.78	-	133,502.78	14,121.87	11.8%
4,500	6,000	50%	1,642,500	130,622.51	146,073.81	-	146,073.81	15,451.30	11.8%
4,500	6,000	75%	2,463,750	158,726.51	177,501.39	-	177,501.39	18,774.88	11.8%
5,000	7,000	20%	730,000	108,464.35	121,295.23	-	121,295.23	12,830.88	11.8%
5,000	7,000	30%	1,095,000	120,955.02	135,263.04	-	135,263.04	14,308.02	11.8%
5,000	7,000	40%	1,460,000	133,445.68	149,230.85	-	149,230.85	15,785.17	11.8%
5,000	7,000	50%	1,825,000	145,936.35	163,198.66	-	163,198.66	17,262.31	11.8%
5,000	7,000	75%	2,737,500	177,163.01	198,118.19	-	198,118.19	20,955.18	11.8%
6,000	8,000	20%	876,000	129,185.62	144,466.99	-	144,466.99	15,281.37	11.8%
6,000	8,000	30%	1,314,000	144,174.41	161,228.36	-	161,228.36	17,053.95	11.8%
6,000	8,000	40%	1,752,000	159,163.21	177,989.74	-	177,989.74	18,826.53	11.8%
6,000	8,000	50%	2,190,000	174,152.01	194,751.11	-	194,751.11	20,599.10	11.8%
6,000	8,000	75%	3,285,000	211,624.01	236,654.54	-	236,654.54	25,030.53	11.8%
7,000	8,500	20%	1,022,000	148,700.88	166,290.13	-	166,290.13	17,589.25	11.8%
7,000	8,500	30%	1,533,000	166,187.81	185,845.07	-	185,845.07	19,657.26	11.8%
7,000	8,500	50%	2,555,000	201,161.68	224,954.94	-	224,954.94	23,793.26	11.8%
7,000	8,500	75%	3,832,500	244,879.00	273,842.28	-	273,842.28	28,963.28	11.8%

E-35 Average Energy On-Peak: 30%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) For purposes of calculating the monthly bill, customers are categorized in this manner:
   0 - 99 kW = self contained
   100 kW and above = Instrument-rated
4) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-36
Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Monthly Bill under Present Rates	Components of Proposed Bill		Monthly Bill under Proposed Rates	Change	
kW	Load Factor	Monthly kWh		Base	EIC		Amount ($)	%
					(C) x $0.00017	(E) + (F)	(G) - (D)	(H) / (D)

No typical bill analysis is presented for Rate Schedule E-36
as the only rate change proposed is to market price determinations.

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-40

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)		(C)	(D)	(E)	(F)	(G)	(H)
				Components of Proposed Bill			Change	
HP	Monthly kWh	Monthly kW	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates	Amount ($)	%
		74.8%				(D) + (E)	(F) - (C)	(G) / (C)
25	-	18.7	32.25	36.06	-	36.06	3.81	11.8%
25	250	18.7	52.43	57.84	-	57.84	5.41	10.3%
25	500	18.7	72.62	79.63	-	79.63	7.01	9.7%
25	750	18.7	92.80	101.41	-	101.41	8.61	9.3%
25	1,000	18.7	112.98	123.20	-	123.20	10.22	9.0%
50	-	37.4	64.50	72.11	-	72.11	7.61	11.8%
50	250	37.4	84.68	93.90	-	93.90	9.22	10.9%
50	500	37.4	104.87	115.68	-	115.68	10.81	10.3%
50	750	37.4	125.05	137.47	-	137.47	12.42	9.9%
50	1,000	37.4	145.23	159.26	-	159.26	14.03	9.7%
75	-	56.1	96.75	108.17	-	108.17	11.42	11.8%
75	250	56.1	116.93	129.96	-	129.96	13.03	11.1%
75	500	56.1	137.12	151.74	-	151.74	14.62	10.7%
75	750	56.1	157.30	173.53	-	173.53	16.23	10.3%
75	1,000	56.1	177.48	195.31	-	195.31	17.83	10.0%
100	-	74.8	129.00	144.23	-	144.23	15.23	11.8%
100	250	74.8	149.18	166.01	-	166.01	16.83	11.3%
100	500	74.8	169.37	187.80	-	187.80	18.43	10.9%
100	750	74.8	189.55	209.58	-	209.58	20.03	10.6%
100	1,000	74.8	209.73	231.37	-	231.37	21.64	10.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-47

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
HPS, cobra / roadway	5,800	29	Company	7.71	8.42	-	8.42	0.71	9.2%
		29	Customer	4.56	4.98	-	4.98	0.42	9.2%
HPS, cobra / roadway	9,500	41	Company	9.08	9.91	-	9.91	0.83	9.2%
		41	Customer	5.58	6.09	-	6.09	0.51	9.2%
HPS, architectural	9,500	41	Company	13.58	14.83	-	14.83	1.25	9.2%
		41	Customer	6.48	7.08	-	7.08	0.60	9.2%
HPS, acorn luminaire	9,500	41	Company	23.90	26.10	-	26.10	2.20	9.2%
		41	Customer	8.14	8.89	-	8.89	0.75	9.2%
HPS, cobra / roadway	16,000	69	Company	11.37	12.42	-	12.42	1.05	9.2%
		69	Customer	7.79	8.51	-	8.51	0.72	9.2%
HPS, architectural	16,000	69	Company	15.86	17.32	-	17.32	1.46	9.2%
		69	Customer	8.67	9.47	-	9.47	0.80	9.2%
HPS, acorn luminaire	16,000	69	Company	26.53	28.97	-	28.97	2.44	9.2%
		69	Customer	10.29	11.24	-	11.24	0.95	9.2%
HPS, cobra / roadway	30,000	99	Company	13.71	14.97	-	14.97	1.26	9.2%
		99	Customer	10.12	11.05	-	11.05	0.93	9.2%
HPS, architectural	30,000	99	Company	18.82	20.55	-	20.55	1.73	9.2%
		99	Customer	11.13	12.15	-	12.15	1.02	9.2%
HPS, cobra / roadway	50,000	153	Company	18.60	20.31	-	20.31	1.71	9.2%
		153	Customer	14.46	15.79	-	15.79	1.33	9.2%
HPS, architectural	50,000	153	Company	23.22	25.35	-	25.35	2.13	9.2%
		153	Customer	16.01	17.48	-	17.48	1.47	9.2%
LPS, architectural	8,000	30	Company	19.74	21.55	-	21.55	1.81	9.2%
		30	Customer	8.67	9.47	-	9.47	0.80	9.2%
LPS, architectural	13,500	50	Company	23.28	25.42	-	25.42	2.14	9.2%
LPS, architectural	22,500	72	Company	26.59	29.03	-	29.03	2.44	9.2%
		72	Customer	12.76	13.93	-	13.93	1.17	9.2%
LPS, architectural	33,000	90	Company	31.99	34.93	-	34.93	2.94	9.2%
		90	Customer	15.03	16.41	-	16.41	1.38	9.2%
Type of Pole	Height	Desc.							
Direct Bury	30 FT	Round	Company	12.70	13.87	-	13.87	1.17	9.2%
		Steel	Customer	N/A					N/A
Direct Bury	34 FT	Square	Company	14.02	15.31	-	15.31	1.29	9.2%
		Steel	Customer	N/A	N/A				N/A

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-58

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
HPS, cobra / roadway	5,800	29	Inv. By Co.	7.71	8.77	-	8.77	1.06	13.7%
		29	Inv. By Others	4.56	5.18	-	5.18	0.62	13.7%
HPS, cobra / roadway	9,500	41	Inv. By Co.	9.08	10.32	-	10.32	1.24	13.7%
		41	Inv. By Others	5.59	6.35	-	6.35	0.77	13.7%
HPS, architectural	9,500	41	Inv. By Co.	13.58	15.44	-	15.44	1.86	13.7%
		41	Inv. By Others	6.48	7.37	-	7.37	0.89	13.7%
HPS, acorn luminaire	9,500	41	Inv. By Co.	23.90	27.18	-	27.18	3.28	13.7%
		41	Inv. By Others	8.14	9.26	-	9.26	1.12	13.7%
HPS, cobra / roadway	16,000	69	Inv. By Co.	11.37	12.93	-	12.93	1.56	13.7%
		69	Inv. By Others	7.79	8.86	-	8.86	1.07	13.7%
HPS, architectural	16,000	69	Inv. By Co.	15.86	18.03	-	18.03	2.17	13.7%
		69	Inv. By Others	8.67	9.86	-	9.86	1.19	13.7%
HPS, acorn luminaire	16,000	69	Inv. By Co.	26.53	30.17	-	30.17	3.64	13.7%
		69	Inv. By Others	10.29	11.70	-	11.70	1.41	13.7%
HPS, cobra / roadway	30,000	99	Inv. By Co.	13.71	15.59	-	15.59	1.88	13.7%
		99	Inv. By Others	10.12	11.51	-	11.51	1.39	13.7%
HPS, architectural	30,000	99	Inv. By Co.	18.82	21.40	-	21.40	2.58	13.7%
		99	Inv. By Others	11.13	12.66	-	12.66	1.53	13.7%
HPS, cobra / roadway	50,000	153	Inv. By Co.	18.60	21.15	-	21.15	2.55	13.7%
		153	Inv. By Others	14.46	16.44	-	16.44	1.98	13.7%
HPS, architectural	50,000	153	Inv. By Co.	23.22	26.40	-	26.40	3.18	13.7%
		153	Inv. By Others	16.01	18.20	-	18.20	2.19	13.7%
LPS, architectural	8,000	30	Inv. By Co.	19.74	22.45	-	22.45	2.71	13.7%
		30	Inv. By Others	8.67	9.86	-	9.86	1.19	13.7%
LPS, architectural	13,500	50	Inv. By Co.	23.28	26.47	-	26.47	3.19	13.7%
LPS, architectural	22,500	72	Inv. By Co.	26.59	30.23	-	30.23	3.64	13.7%
		72	Inv. By Others	12.76	14.51	-	14.51	1.75	13.7%
LPS, architectural	33,000	90	Inv. By Co.	31.99	36.37	-	36.37	4.38	13.7%
		90	Inv. By Others	15.03	17.09	-	17.09	2.06	13.7%
Type of Pole	Height	Desc.							
Direct Bury	30 FT	Round	Inv. By Co.	12.70	14.44	-	14.44	1.74	13.7%
		Steel	Inv. By Others	2.35	2.67	-	2.67	0.32	13.7%
Direct Bury	34 FT	Square	Inv. By Co.	14.02	15.94	-	15.94	1.92	13.7%
		Steel	Inv. By Others	2.43	2.76	-	2.76	0.33	13.7%
Direct Bury	38 FT	Square	Inv. By Co.	15.06	17.12	-	17.12	2.06	13.7%
		Steel	Inv. By Others	2.61	2.97	-	2.97	0.36	13.7%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-59

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
Lamps	kWh per Lamp	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
50	30	1,500	203.78	227.86	-	227.86	24.08	11.8%
50	60	3,000	284.55	318.18	-	318.18	33.63	11.8%
50	75	3,750	324.94	363.35	-	363.35	38.41	11.8%
50	100	5,000	392.25	438.61	-	438.61	46.36	11.8%
50	150	7,500	526.88	589.15	-	589.15	62.27	11.8%
100	30	3,000	407.55	455.72	-	455.72	48.17	11.8%
100	60	6,000	569.10	636.37	-	636.37	67.27	11.8%
100	75	7,500	649.88	726.69	-	726.69	76.81	11.8%
100	100	10,000	784.50	877.23	-	877.23	92.73	11.8%
100	150	15,000	1,053.75	1,178.30	-	1,178.30	124.55	11.8%
200	30	6,000	815.10	911.44	-	911.44	96.34	11.8%
200	60	12,000	1,138.20	1,272.74	-	1,272.74	134.54	11.8%
200	75	15,000	1,299.75	1,453.38	-	1,453.38	153.63	11.8%
200	100	20,000	1,569.00	1,754.46	-	1,754.46	185.46	11.8%
200	150	30,000	2,107.50	2,356.61	-	2,356.61	249.11	11.8%
500	30	15,000	2,037.75	2,278.61	-	2,278.61	240.86	11.8%
500	60	30,000	2,845.50	3,181.84	-	3,181.84	336.34	11.8%
500	75	37,500	3,249.38	3,633.45	-	3,633.45	384.07	11.8%
500	100	50,000	3,922.50	4,386.14	-	4,386.14	463.64	11.8%
500	150	75,000	5,268.75	5,891.52	-	5,891.52	622.77	11.8%
1,000	30	30,000	4,075.50	4,557.22	-	4,557.22	481.72	11.8%
1,000	60	60,000	5,691.00	6,363.68	-	6,363.68	672.68	11.8%
1,000	75	75,000	6,498.75	7,266.90	-	7,266.90	768.15	11.8%
1,000	100	100,000	7,845.00	8,772.28	-	8,772.28	927.28	11.8%
1,000	150	150,000	10,537.50	11,783.03	-	11,783.03	1,245.53	11.8%
2,000	30	60,000	8,151.00	9,114.45	-	9,114.45	963.45	11.8%
2,000	60	120,000	11,382.00	12,727.35	-	12,727.35	1,345.35	11.8%
2,000	75	150,000	12,997.50	14,533.80	-	14,533.80	1,536.30	11.8%
2,000	100	200,000	15,690.00	17,544.56	-	17,544.56	1,854.56	11.8%
2,000	150	300,000	21,075.00	23,566.07	-	23,566.07	2,491.07	11.8%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-67

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Components of Proposed Bill			Change	
Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates	Amount ($)	%
				(C) + (D)	(E) - (B)	(F) / (B)
30	1.37	1.54	-	1.54	0.17	12.4%
40	1.83	2.05	-	2.05	0.22	12.0%
50	2.29	2.56	-	2.56	0.27	11.8%
60	2.75	3.07	-	3.07	0.32	11.6%
70	3.21	3.59	-	3.59	0.38	11.8%
80	3.66	4.10	-	4.10	0.44	12.0%
90	4.12	4.61	-	4.61	0.49	11.9%
100	4.58	5.12	-	5.12	0.54	11.8%
125	5.73	6.41	-	6.41	0.68	11.9%
150	6.87	7.69	-	7.69	0.82	11.9%
175	8.02	8.97	-	8.97	0.95	11.8%
200	9.16	10.25	-	10.25	1.09	11.9%
225	10.31	11.53	-	11.53	1.22	11.8%
250	11.45	12.81	-	12.81	1.36	11.9%
275	12.60	14.09	-	14.09	1.49	11.8%
300	13.74	15.37	-	15.37	1.63	11.9%
325	14.89	16.65	-	16.65	1.76	11.8%
350	16.03	17.93	-	17.93	1.90	11.9%
375	17.18	19.22	-	19.22	2.04	11.9%
400	18.32	20.50	-	20.50	2.18	11.9%
425	19.47	21.78	-	21.78	2.31	11.9%
450	20.61	23.06	-	23.06	2.45	11.9%
475	21.76	24.34	-	24.34	2.58	11.9%
500	22.90	25.62	-	25.62	2.72	11.9%
600	27.48	30.74	-	30.74	3.26	11.9%
700	32.06	35.87	-	35.87	3.81	11.9%
800	36.64	40.99	-	40.99	4.35	11.9%
900	41.22	46.12	-	46.12	4.90	11.9%
1,000	45.80	51.24	-	51.24	5.44	11.9%
1,500	68.70	76.86	-	76.86	8.16	11.9%
2,000	91.60	102.48	-	102.48	10.88	11.9%
2,500	114.50	128.10	-	128.10	13.60	11.9%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis
E-221 Water Pumping

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Components of Proposed Bill			Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (E) + (F)	Amount ($) (G) - (D)	% (H) / (D)
10	20%	1,460	141.66	160.55	-	160.55	18.89	13.3%
10	35%	2,555	218.42	246.65	-	246.65	28.24	12.9%
10	50%	3,650	286.89	323.47	-	323.47	36.57	12.7%
10	65%	4,745	349.91	394.16	-	394.16	44.25	12.6%
10	80%	5,840	412.93	464.85	-	464.85	51.92	12.6%
30	20%	4,380	379.55	427.41	-	427.41	47.86	12.6%
30	35%	7,665	609.83	685.73	-	685.73	75.90	12.4%
30	50%	10,950	809.23	909.42	-	909.42	100.18	12.4%
30	65%	14,235	998.29	1,121.49	-	1,121.49	123.21	12.3%
30	80%	17,520	1,187.34	1,333.57	-	1,333.57	146.23	12.3%
75	20%	10,950	914.81	1,027.85	-	1,027.85	113.04	12.4%
75	35%	19,163	1,490.54	1,673.69	-	1,673.69	183.15	12.3%
75	50%	27,375	1,984.50	2,227.81	-	2,227.81	243.31	12.3%
75	65%	35,588	2,457.16	2,758.03	-	2,758.03	300.87	12.2%
75	80%	43,800	2,929.76	3,288.18	-	3,288.18	358.42	12.2%
100	20%	14,600	1,212.17	1,361.43	-	1,361.43	149.25	12.3%
100	35%	25,550	1,979.77	2,222.50	-	2,222.50	242.73	12.3%
100	50%	36,500	2,637.42	2,960.25	-	2,960.25	322.82	12.2%
100	65%	47,450	3,267.60	3,667.16	-	3,667.16	399.56	12.2%
100	80%	58,400	3,897.77	4,374.08	-	4,374.08	476.31	12.2%
150	20%	21,900	1,806.90	2,028.58	-	2,028.58	221.68	12.3%
150	35%	38,325	2,958.29	3,320.19	-	3,320.19	361.90	12.2%
150	50%	54,750	3,943.27	4,425.12	-	4,425.12	481.85	12.2%
150	65%	71,175	4,888.53	5,485.49	-	5,485.49	596.96	12.2%
150	80%	87,600	5,833.79	6,545.87	-	6,545.87	712.08	12.2%
200	20%	29,200	2,401.63	2,695.74	-	2,695.74	294.11	12.2%
200	35%	51,100	3,936.82	4,417.88	-	4,417.88	481.06	12.2%
200	50%	73,000	5,249.12	5,890.00	-	5,890.00	640.87	12.2%
200	65%	94,900	6,509.47	7,303.83	-	7,303.83	794.36	12.2%
200	80%	116,800	7,769.81	8,717.66	-	8,717.66	947.84	12.2%
300	20%	43,800	3,591.09	4,030.05	-	4,030.05	438.96	12.2%
300	50%	109,500	7,860.82	8,819.75	-	8,819.75	958.93	12.2%
300	65%	142,350	9,751.34	10,940.50	-	10,940.50	1,189.15	12.2%
300	80%	175,200	11,641.86	13,061.24	-	13,061.24	1,419.38	12.2%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis
E-221-8T Time-of-Use Water Pumping

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
					Components of Proposed Bill			Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Monthly Bill under Proposed Rates (F) + (G)	Amount ($) (H) - (E)	% (I) / (E)
10	30	20%	1,460	219.33	248.86	-	248.86	29.53	13.5%
10	30	35%	2,555	281.95	319.11	-	319.11	37.16	13.2%
10	30	50%	3,650	344.58	389.36	-	389.36	44.78	13.0%
10	30	65%	4,745	407.20	459.61	-	459.61	52.41	12.9%
10	30	80%	5,840	469.83	529.86	-	529.86	60.03	12.8%
30	90	20%	4,380	606.93	683.66	-	683.66	76.73	12.6%
30	90	35%	7,665	794.80	894.41	-	894.41	99.61	12.5%
30	90	50%	10,950	982.67	1,105.17	-	1,105.17	122.50	12.5%
30	90	65%	14,235	1,170.54	1,315.92	-	1,315.92	145.38	12.4%
30	90	80%	17,520	1,358.42	1,526.67	-	1,526.67	168.25	12.4%
75	225	20%	10,950	1,479.02	1,661.96	-	1,661.96	182.94	12.4%
75	225	35%	19,163	1,948.73	2,188.87	-	2,188.87	240.14	12.3%
75	225	50%	27,375	2,418.38	2,715.72	-	2,715.72	297.34	12.3%
75	225	65%	35,588	2,888.09	3,242.63	-	3,242.63	354.54	12.3%
75	225	80%	43,800	3,357.75	3,769.48	-	3,769.48	411.73	12.3%
100	300	20%	14,600	1,963.52	2,205.46	-	2,205.46	241.94	12.3%
100	300	35%	25,550	2,589.76	2,907.97	-	2,907.97	318.21	12.3%
100	300	50%	36,500	3,216.00	3,610.47	-	3,610.47	394.47	12.3%
100	300	65%	47,450	3,842.24	4,312.98	-	4,312.98	470.74	12.3%
100	300	80%	58,400	4,468.48	5,015.48	-	5,015.48	547.00	12.2%
150	450	20%	21,900	2,932.51	3,292.46	-	3,292.46	359.95	12.3%
150	450	35%	38,325	3,871.88	4,346.22	-	4,346.22	474.34	12.3%
150	450	50%	54,750	4,811.24	5,399.97	-	5,399.97	588.73	12.2%
150	450	65%	71,175	5,750.60	6,453.73	-	6,453.73	703.13	12.2%
150	450	80%	87,600	6,689.96	7,507.49	-	7,507.49	817.53	12.2%
200	600	20%	29,200	3,901.51	4,379.46	-	4,379.46	477.95	12.3%
200	600	35%	51,100	5,153.99	5,784.47	-	5,784.47	630.48	12.2%
200	600	50%	73,000	6,406.47	7,189.48	-	7,189.48	783.01	12.2%
200	600	65%	94,900	7,658.96	8,594.49	-	8,594.49	935.53	12.2%
200	600	80%	116,800	8,911.44	9,999.50	-	9,999.50	1,088.06	12.2%
300	900	20%	43,800	5,839.50	6,553.45	-	6,553.45	713.95	12.2%
300	900	50%	109,500	9,596.94	10,768.48	-	10,768.48	1,171.54	12.2%
300	900	65%	142,350	11,475.67	12,876.00	-	12,876.00	1,400.33	12.2%
300	900	80%	175,200	13,354.39	14,983.52	-	14,983.52	1,629.13	12.2%

E-221-8T Average Energy On-Peak: 30%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include RES, EIS, PSA, CRCC, DSMAC, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 7/1/2007.
3) Bill comparison is for present and proposed base rates only

Arizona Public Service Company
Test Year Ending December 2007
Typical General Service Bill Analysis

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(F)	(G)	(G)	(H)
						Change	
			Monthly Bill	Components of Proposed Bill			
kW	Load Factor	Monthly kWh	under Present Rates	Base	Transmission	Amount ($) (H) - (D)	% (I) / (D)

No typical bill analysis is presented for the following General Service Rate Schedules:

E-21
E-22
E-23
E-24
E-32R
E-53
E-54

as no rate changes are proposed for these schedules.

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(F)	(G)	(G)	(H)
				Components of Proposed Bill		Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Amount ($) (H) - (D)	% (I) / (D)

No typical bill analysis is presented for the following Classified Service Rate Schedules:

E-38
E-38-8T
E-51
E-55
E-56
E-66
E-114
E-116
E-145
E-249
Solar-1
Solar-2
Solar-3
SP-1

as no rate changes are proposed for these schedules.

Arizona Public Service Company
Test Year Ending December 2007
Typical Classified Service Bill Analysis

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(F)	(G)	(G)	(H)
				Components of Proposed Bill		Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	Transmission	Amount ($) (H) - (D)	% (I) / (D)

No typical bill analysis is presented for the following Residential Service Rate Schedules:

E-10
EC-1

as no rate changes are proposed for these schedules.

ALL-STATE LEGAL®
EXHIBIT
S-10
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

SUPPORTING THE SETTLEMENT AGREEMENT

OF

ERNEST G. JOHNSON

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 1, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

SECTION I – SETTLEMENT PROCESS 3

SECTION II – PUBLIC INTEREST 7

SECTION III – POLICY CONSIDERATIONS 14

POST TEST YEAR PLANT *15*
COST OF CAPITAL (COMMON EQUITY) *16*
APS EXPENSE REDUCTION COMMITMENT *17*
FUEL AND POWER SUPPLY ADJUSTMENT *17*
EQUITY INFUSIONS *17*
PENSION AND OPEB DEFERRALS *18*
SCHEDULE 3 ..... *19*
LOW-INCOME PROGRAM *21*

SECTION IV – COMMISSIONERS LETTERS 22

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

Mr. Johnson provides policy level testimony in support of the Settlement Agreement ("Agreement"). Mr. Johnson's testimony summarizes the settlement process, provides reasons which support Staff's conclusions that the Agreement is in the public interest, and addresses several general policy considerations underlying the provisions in the Agreement.

The Agreement's provisions are broken down into the following broad substantive categories:

II) Rate Case Stability Provisions
III) Rate Increase
IV) Cost of Capital
V) Depreciation
VI) Fuel and Power Supply Adjustment Provisions
VII) APS Expense Reduction Commitment
VIII) Equity Infusions to be Made by APS
IX) Pension and OPEB Deferrals
X) Treatment of Schedule 3
XI) Adjustment of Depreciation Rates for Palo Verde License Extension
XII) Limit on Recovery of Annual Cash Incentive Compensation for APS Executives
XIII) Periodic Evaluation
XIV) Demand Side Management
XV) Renewable Energy
XVI) Low Income Programs
XVII) Revenue Spread
XVIII) Rate Design
XIX) Interruptible Rate Schedules and Other Demand Reduction Programs
XX) Demand Response
XXI) Other

In addition to Mr. Johnson's testimony highlighting policy considerations underlying the Agreement's provisions, Staff will be presenting three other witnesses who will also be providing testimony in support of the Agreement. Mr. Ralph Smith will address the Agreement from an accounting and revenue requirements perspective. More specifically, his testimony will focus on Sections III, IV, V, VI, VIII, IX, X and XI of the Agreement. Ms. Barbara Keene will address Schedule 3, Renewable Energy, Demand-side Management, and the PSA Plan of Administration. Her testimony covers Sections VI, X, XIV, and XV of the Agreement. Finally, Mr. Frank Radigan will address the rate design provisions contained in the Agreement, including inclining Block Rate, Time of Use Rates and other rate design changes or other rate schedule matters. His testimony covers Sections XVII and XVIII of the Agreement.

The agreed upon provisions in each of these areas were the result of many hours of negotiation and a lot of give and take on the part of all of the parties. The settlement process was open, transparent and inclusive. In the end, while the total rate increase reflected in the Agreement was higher than what Staff had recommended in its Direct Testimony, the increase and other revenue requirement provisions are designed to improve the Company's financial metrics and bond ratings which the Signatories believe will ultimately benefit not only APS but also its customers by allowing the Company to borrow at more attractive rates, and by improving its credit worthiness which should improve its operational flexibility. The provisions are also designed to ensure more predictability and stability in rate case filings by APS over the next few years. In addition, I believe that the Agreement puts the Company on the right path with respect to Arizona's energy future. The Agreement contains a myriad of important commitments by the Company to invest in and make available various renewable energy and demand-side management programs. The Agreement also contains new rate design options designed to move load to off peak hours.

The Agreement also establishes performance measurements that APS must meet in order to recover the costs of increases to executive cash incentive compensation beyond test year levels. The Agreement also contains important reporting requirements and makes provision for a Benchmarking Study whereby APS' performance in a number of areas will be compared to a peer group of companies with similar characteristics.

Finally, the Agreement is in the public interest because of all of the important benefits to customers which I highlight below:

Investment in Arizona's Energy Future.

- Establishment of energy efficiency goals and the creation of tiered performance incentives to encourage meeting those goals;
- At least 100 schools served by DSM programs and at least 1,000 customers in existing homes served by the Home Performance enhanced program element by December 31, 2010;
- Placement of renewable energy projects at Arizona schools and government institutions;
- A plan for utility scale photovoltaic generation and an RFP for in-state wind generation;
- Additional renewable energy projects to be in place by 2015 which, in combination with existing renewable commitments, will result in approximately 10% of APS' retail sales coming from renewable resources; and,
- Construction of one or more renewable energy transmission facilities.

Commitments Benefiting Low-Income Customers.

- Continued rate discounts for low income ratepayers, holding these ratepayers harmless from the rate increase;

- Creation of a new bill assistance program to benefit customers whose incomes exceed 150% of the Federal Poverty Income Guidelines but are less than or equal to 200% of the Federal Poverty Income Guidelines, funded by APS; and,
- Waiving additional security deposits for low income ratepayers.

Rate Stability Plan.

- An increase in rate stability, including an extended period without base rate increases and a scheduled plan for future rate cases, resulting in greater administrative efficiency and reduced uncertainty for both APS and ratepayers.

Rate Related Benefits.

- An improvement in APS' ability to attract capital, maintain reliability and sustain growth;
- A limit on recovery through rates in certain circumstances of executive incentive compensation based upon performance;
- A sustained reduction of expenses of at least an average of $30 million per year over the Plan Term, which will reduce the need for future rate increases;
- An infusion of at least $700 million of additional equity strengthen APS' bond rating and reduce its future debt costs;
- A plan to be prepared by APS to maintain investment grade financial ratios and improve APS' financial metrics;
- An acceleration of the refund of any potential over-collected amounts in the PSA account, resulting in a lower adjustor rate that would partially offset the base rate increase;
- A reduced Systems Benefits Charge in 2012 if a Palo Verde license extension is approved before the conclusion of the next rate case; and,
- Continued 90/10 sharing of the PSA.

Creation of Performance Measures for APS.

New Rate Design Options.

- Creation of an optional super-peak tariff for residential customers and other critical peak pricing rates;
- Twelve month reopening of the E-20 House of Worship tariff;
- Development of Interruptible Rate Schedules and other Demand Response Programs for large customers; and,
- A new optional time of use rate for schools.

The total rate increase reflected in the Agreement is $344,738,000. This includes a Base Rate Increase of approximately $131.1 million over the interim rate increase of $65.2 million, or

a total Base Rate Increase of $196.3 million. The percentage Base Rate Increase, including both the interim increase and the $11.2 million of revenue associated with establishing new base fuel levels represents a 7.9% increase in base rate revenue. The total rate increase reflected in the Agreement also includes an increase in base fuel costs of $137.2 million. The total rate increase, including both the Base Rate Increase and the increase in base fuel costs, represents a 13.07% increase in rates. In addition to the Base Rate Increase, various of the Agreement's provisions relating to fuel and purchased power costs, renewable energy, and energy efficiency may have the impact of increasing or decreasing the amounts collected from customers under the Company's various adjustor mechanisms.

The bill impact analysis filed by the Signatories indicates that 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 $6.332 per month. Estimates of the 2010 DSM Adjustment Clause and the 2010 RES were included in the bill impact analysis for illustrative purposes, but those adjustments will not be implemented at the same time as base rate increases.

My overall recommendation to the Commission is to approve the Agreement because it strikes an appropriate balance between APS' ratepayers and its shareholders, and is in the public interest.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Ernest G. Johnson, 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("ACC" or "Commission") as the Director of the Utilities Division.

Q. Briefly describe your responsibilities as Utilities Director.

A. I am responsible for the day-to-day operations of the Utilities Division, including policy development, case strategy, and overall Division management.

Q. Please summarize your educational background and professional experience.

A. In 1979 and 1982, respectively, I earned Bachelor of Science and Juris Doctorate degrees, both from the University of Oklahoma. I have been involved in the regulation of public utilities since 1986. I was employed by the Oklahoma Corporation Commission in 1986 in various legal capacities. In 1993, I was named acting Director and served in that position until mid-1994. I served as permanent Director from mid-1994 until October 2001. In October of 2001, I assumed my current position with the Arizona Corporation Commission. While serving in these capacities, I have participated in numerous regulatory proceedings, including providing policy analysis concerning Electric Restructuring before the Oklahoma Corporation Commission, the Oklahoma State Legislature, and the Arizona Commission.

Q. Did you participate in the negotiations that led to the execution of the Proposed Agreement?

A. Yes, I did.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to support the Settlement Agreement ("Agreement").

Q. How is your testimony being presented?

A. My testimony is organized into four sections. Section I provides discussion and insight into the Settlement process. Section II identifies and discusses the reasons why the Settlement Agreement ("Agreement") is in the public interest. Section III addresses several general policy considerations. Section IV is responsive to Commissioners letters filed in the docket.

Q. Who else is providing Staff testimony, and what issues will they address?

A. Staff will present the following witnesses:

Staff's Consultant Ralph Smith will be covering in more detail the technical areas of revenue deficiency, accounting, and depreciation rates as well as the following sections of the Settlement Agreement:

III. Rate Increase
IV. Cost of Capital
V. Depreciation
VI. Fuel and Power Supply Adjustment provisions
VIII. Equity Infusions
IX. Pension and OPEB Defferals
X. Treatment of Schedule 3
XI. Adjustment of Depreciation rates for Palo Verde License extension

Staff Witness Barbara Keene will be covering in more detail the Settlement Sections that pertain directly to the following:

- System Facility Charge.
- Impact fee.
- Revisions to Schedule 3.
- Renewable Energy.
- Demand-Side Management.
- PSA Plan of Administration.

Staff Witness Frank Radigan will be covering in more detail the Settlement Sections that pertain to the following:

Rate Design including:

- Inclining Block Rate.
- Time of Use.
- Interruptible Rate Schedules and other Demand Reduction Programs.
- Demand Response.
- Other Rate Design Changes.
- Other rate schedule matters.

SECTION I – SETTLEMENT PROCESS

Q. Please discuss the Settlement process.

A. The Settlement process was open, transparent, and inclusive. All parties received notice of the Settlement meetings and were accorded an opportunity to raise, discuss, and propose resolution to any issues that they desired.

Q. How many Settlement meetings were held?

A. There were approximately 21 meetings held on the following dates:

January 30, 2009, February 5, 2009, February 10, 2009, February 13, 2009, February 18, 2009, February 25, 2009, March 2, 2009, march 10, 2009, March 16, 2009, March 25,

2009, April 6, 2009, April 21, 2009, April 24, 2009, May 1, 2009, May 7, 2009, May 21, 2009, June 1, 2009, June 4, 2009, June 8, 2009, June 10, 2009 and June 11, 2009.

Q. Who participated in those meetings?

A. The following parties were participants in all or some of the Settlement meetings: Arizona Public Service Company ("APS"), AzAg Group, Arizona Association of School Business Officials ("AASBO"), Arizona Investment Council ("AIC"), Arizona School Boards Association ("ASBA"), Arizonans for Electric Choice and Competition ("AECC"), Bowie Power Station, LLC ("Bowie"), Cynthia Zwick, Federal Executive Agencies ("FEA"), Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan"), IBEW Locals 387, 640, 769, Interwest Energy Alliance ("Interwest"), Kroger Co. ("Kroger"), Mesquite Power, LLC ("Mesquite"), Residential Utility Consumer Office ("RUCO"), Southwest Energy Efficiency Project ("SWEEP"), Southwestern Power Group II, LLC ("SWPG"), Town of Wickenburg, Western Resource Advocates ("WRA") and the Arizona Corporation Commission Utilities Division ("Staff").

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. The participants represented very diverse interests and included Staff, RUCO, APS, a shareholder association, consumer representatives, merchant plants, large customers of APS, federal agencies, demand side management ("DSM") advocates, low-income customer advocates, and renewable energy advocates, just to name a few.

Q. How many of these parties executed the stipulation?

A. Approximately 20 parties executed the Agreement.

Q. Were there other parties who were not Signatories to the Agreement?

A. Yes, one intervenor, Barbara Wyllie-Pecora, who had specific concerns about APS' line extension tariff, is not a Signatory to the Agreement.

Q. Did Staff and the Signatories to the Agreement meet with all the interested parties in Docket?

A. Yes. Staff and other Signatories met with the Wyllies on March 16, 2009, to discuss the issue on line extension (Schedule 3). Also, on May 15, 2009, Commission Staff met with Mike Wyllie to discuss the Schedule 3 issue and assist them in understanding the Commission process to include but not limited to open record request.

Q. In your opinion, was there an opportunity for all issues to be discussed and considered?

A. Yes. In my opinion, each party had the opportunity to raise and have their issues considered.

Q. Were the Signatories able to resolve all issues?

A. Yes, the Signatories were able to resolve and reach agreement on all issues.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented the interests of their constituents. I would characterize the discussions as candid but professional. I am extremely pleased with the desire and effort put forth by all parties. I must note that all parties had the opportunity to be heard and to have their issues fairly considered.

Q. Mr. Johnson, would you describe the process as requiring a lot of give and take?

A. Yes, I would. As a result of the many and varied interests represented in the Settlement process, a willingness to compromise was absolutely necessary. As evidenced in the Agreement, the Signatories compromised vastly different litigation positions.

Q. In your previous response, you stated that the parties were able to settle despite vastly different litigation positions. Is that correct?

A. Yes.

Q. In your opinion, was the public interest unduly compromised?

A. No, not in my opinion. As I will discuss later in this testimony, I believe that the compromises made by the various parties will actually further the public interest.

Q. Mr. Johnson, you have indicated that the Settlement Proposal incorporates many diverse interests, including those of low-income customers, residential, commercial, industrial customers, merchant generators, and retail energy marketers. Please indicate how the Agreement takes these into account.

A. Within the Agreement, there are specific provisions which address many of the concerns expressed by the above-referenced interests. Examples include, Section XIV to include Energy Efficiency (DSM), Section XV Renewable Energy, Section XVI Low-Income, Section XIX Interruptable Rates, and Section XX Demand Response.

Q. Mr. Johnson, are there any other comments you would like to make in regard to the Settlement process?

A. Yes. In my view, the Settlement process resulted in an Agreement which some may not view as perfect but nonetheless is balanced and consistent with the public interest.

SECTION II – PUBLIC INTEREST

Q. Mr. Johnson, in Staff's opinion, is the Proposed Settlement in the public interest?

A. Yes absolutely. In Staff's opinion, the Proposed Settlement is fair, balanced, and in the public interest.

Q. Mr. Johnson, would you briefly summarize the reasons that Staff concludes that the Settlement is fair, balanced, and in the public interest.

A. The agreed upon provisions in each of these areas were the result of many hours of negotiation and a lot of give and take on the part of all of the parties. The settlement process was open, transparent and inclusive. In the end, while the total rate increase reflected in the Agreement was higher than what Staff had recommended in its Direct Testimony, the increase and other revenue requirement provisions are designed to improve the Company's financial metrics and bond ratings which the Signatories believe will ultimately benefit not only APS but also its customers by allowing the Company to borrow at more attractive rates, and by improving its credit worthiness which should improve its operational flexibility. The provisions are also designed to ensure more predictability and stability in rate case filings by APS over the next few years. In addition, I believe that the Agreement puts the Company on the right path with respect to Arizona's energy future. The Agreement contains a myriad of important commitments by the Company to invest in and make available various renewable energy and demand-side management programs. The Agreement also contains new rate design options designed to move load to off peak hours.

The Agreement also establishes performance measurements that APS must meet in order to recover the costs of increases to executive cash incentive compensation beyond test year levels. The Agreement also contains important reporting requirements and makes

provision for a Benchmarking Study whereby APS' performance in a number of areas will be compared to a peer group of companies with similar characteristics.

The Agreement also provides many benefits for customers including:

a) Investments in Arizona's Energy Future.

- Establishment of energy efficiency goals and the creation of tiered performance incentives to encourage meeting those goals;
- At least 100 schools served by DSM programs and at least 1,000 customers in existing homes served by the Home Performance enhanced program element by December 31, 2010;
- Placement of renewable energy projects at Arizona schools and government institutions;
- A plan for utility scale photovoltaic generation and an RFP for in-state wind generation;
- Additional renewable energy projects to be in place by 2015 which, in combination with existing renewable commitments, will result in approximately 10% of APS' retail sales coming from renewable resources; and,
- Construction of one or more renewable energy transmission facilities.

b) Commitments Benefiting Low-Income Customers.

- Continued rate discounts for low-income ratepayers, holding these ratepayers harmless from the rate increase;
- Creation of a new bill assistance program to benefit customers whose incomes exceed 150% of the Federal Poverty Income Guidelines but are less than or equal to 200% of the Federal Poverty Income Guidelines, funded by APS; and,
- Waiving additional security deposits for low-income ratepayers.

c) Rate Stability Plan.

- An increase in rate stability, including an extended period without base rate increases and a scheduled plan for future rate cases, resulting in greater administrative efficiency and reduced uncertainty for both APS and ratepayers.

d) Rate Related Benefits.

- An improvement in APS' ability to attract capital, maintain reliability and sustain growth;
- A limit on recovery through rates in certain circumstances of executive incentive compensation based upon performance;
- A sustained reduction of expenses of at least $30 million per year, which will reduce the need for future rate increases;
- An infusion of at least $700 million of additional equity and an improvement in APS' financial metrics, strengthening its bond rating and reducing future debt costs;
- A plan to be prepared by APS to maintain investment grade financial ratios and improve APS' financial metrics;
- A potential acceleration of the refund of any over-collected amounts in the PSA account, resulting in a lower adjustor rate that would partially offset the base rate increase;
- A reduced Systems Benefits Charge in 2012 if a Palo Verde license extension is approved before the conclusion of the next rate case; and,
- Continuation of the 90/10 sharing provisions in the PSA.

e) Creation of Performance Measures for APS.

f) New Rate Design Options.

- Creation of an optional super-peak tariff for residential customers and other critical peak pricing rates;
- Twelve month reopening of the E-20 House of Worship tariff;
- Development of Interruptible Rate Schedules and other Demand Response Programs for large customers; and,
- A new optional time of use rate for schools.

Q. Are there other reasons why Staff believes the Agreement promotes the public interest?

A. Yes, additional benefits of the Settlement Agreement include:

- No base rate increase to low-income customers.
- Limits the base rate revenue increase to approximately 7.9 percent.
- Implements a demand-side management and performance incentive.
- Provides for expanded time-of-use options to customers.

Q. Mr. Johnson, do you believe that the Settlement results in just and reasonable rates for consumers. Please explain.

A. Yes. In its 2008 Rate Application, APS proposed a rate increase in the amount of $488 million. Staff recommended a rate increase of $307 million. In the proposed Agreement, the Signatories recommend approximately $345 million which represents an increase that is $143 million less than the Company requested. While the amount represents an approximately $38 million increase over Staff's Direct Testimony, the Agreement contains many provisions designed to benefit consumers which I have already discussed.

It is also important to take note of the extraordinary financial times facing APS, its customers, and others. As the Agreement points out, in the fall of 2008, pre-existing difficulties in the subprime mortgage market escalated, resulting in one of the most severe financial crises in the debt and equity markets this country has seen. That crisis underscored the importance for companies like APS to maintain financial metrics in order to (i) allow access to the volatile and uncertain financial markets to secure necessary financing at reasonable rates, and (ii) allow APS to obtain credit from vendors and lenders on reasonable terms. That financial crisis continues today. As part of that crisis, Arizona and the rest of the nation have also entered into a severe recession which is negatively impacting APS, its customers and other interested parties.

Q. Mr. Johnson, with the background you just shared, is it your view that the revenue requirement set forth in the Agreement results in appropriate utility revenue and just and reasonable rates for consumers?

A. Yes, that is my opinion. Staff believes that the Agreement is fair to ratepayers because it results in just and reasonable rates for consumers. Staff believes that it is fair to the utility because it provides revenues necessary for the utility to provide reliable electric service

along with an opportunity for a reasonable profit. Staff believes that this proposal balances many diverse interests, including those of low-income, residential, commercial, and industrial customers, merchant generators, retail energy marketers, and other stakeholders. Staff believes that the Agreement promotes the public interest by facilitating the provision of reliable electric service at reasonable rates.

Q. Please discuss how the Settlement is fair to the utility.

A. As noted in the Agreement, the settling parties included an additional revenue requirement amount related to recognizing post test year plant through June 30, 2009. In addition, illustratively, the Settlement would provide APS with revenues which would allow it an opportunity to earn an overall rate of return of approximately 6.65 percent on fair value rate base of $7.666 billion[1], and an 11 percent return on equity[2]. Also, Staff made a higher adjustment to the fair value rate of return. Staff believes that the Agreement is fair to the utility because it provides an opportunity for APS to earn revenues sufficient for the utility to provide reliable electric service and to achieve a reasonable profit.

As noted by the Agreement, the Signatories believe that the Agreement creates a rate and financial stability program for APS that appropriately balances the risks of APS, its employees, its customers, and other interested parties. The Agreement creates a frame work that could ultimately improve APS' financial metrics and bond ratings which over the long term would also benefit customers by allowing APS to borrow at more attractive rates and also improve its vendor lender credit worthiness thereby creating financial flexibility. The Signatories also believe that the Agreement results in just and reasonable rates for APS and its customers and avoids unnecessary litigation and delay.

[1] See, e.g., Settlement Agreement paragraphs 3.5 and 4.3.
[2] See, e.g., Settlement Agreement paragraph 4.2.

Q. Mr. Johnson, please explain how Staff and the other Signatories came up with the $196.3 million Base Rate Increase?

A. Yes. The $196.3 million was arrived at through the process of vigorous negotiation among the Signatories. Among other things, as stated on page 12, Section 3.4 of the Agreement, the $196.3 million Base Rate Increase incorporates, in addition to other items contained in Staff's Direct Case, a return on and of post test year plant through June 30, 2009, 18 months beyond the test year ending December 31, 2007. As also noted in the Agreement Paragraph 3.4, the Signatories desired to enhance APS' ability to retain and improve its current investment grade credit rating, thereby enabling the Company to attract capital at reasonable cost and to also optimize its operational flexibility.

Q. Mr. Johnson, for ratemaking purposes, is Arizona a future test year state?

A. No. As stated in my Direct Testimony, specifically on pages 4 lines 13 - 15, "This jurisdiction has traditionally utilized an adjusted historical test period in contrast to a forecasted, future or partially projected test year period."

Q. Mr. Johnson, can you please explain why Staff recommended the inclusion of post test year plant in determining the Revenue Requirement?

A. Yes, I will discuss the detail in the policy recommendation section of my testimony.

Q. Please discuss how the 11 percent Return on Equity proposed in the Agreement was derived?

A. As previously stated, the Settlement provides for a Fair Value Rate of Return of 6.65 percent on Fair Value Rate Base and would allow APS the opportunity to earn an 11.0 percent return on equity[3]. In Staff's opinion, it is necessary given the current economic

[3] See, e.g., Settlement Agreement paragraphs 3.5, 4.2 and 4.3.

downturn for APS to have sufficient revenues and reasonable access to capital, which will allow it to properly maintain its system and provide reliable electrical service.

Q. How did the current financial circumstances and APS' need to have reasonable access to capital affect the Agreement reached in this case?

A. There has been much discussion in the APS current base rate case, its prior rate case and in APS' requests for emergency rate relief and/or interim rates about APS' bond rating and the impact that a downgrade to a below-investment-grade rating would have on APS' financing costs. APS' bond rating has been and currently is investment grade; however, concerns have been raised because it is at the lowest level of investment grade under at least one of the three major bond rating agencies rankings. The Signatories to the Agreement believe that it is in the best interests of APS, and APS' ratepayers for the Company to maintain and preferably improve upon its current investment grade bond rating, as this will help facilitate APS' access to the capital markets and will help minimize the amount of future financing costs borne by ratepayers. At one point, the Company suggested that the cost to ratepayers of a non-investment grade rating could be as much as $1 billion over 10 years.[4]

The Settlement Agreement includes several provisions that are intended to help support APS' access to financing on reasonable terms, including the Base Rate Increase, a General Rate Case Filing Plan, a commitment for equity infusions, expense reduction commitments, certain special accounting treatments, as well as performance and reporting requirements and a benchmarking study.

[4] This is acknowledged in Settlement paragraph 1.4. As the worldwide financial crisis has unfolded, the spread between the required yield for investment grade and "junk" rated debt may have even expanded beyond the point when this estimate had been made, and whether there is even a market now for issuing new "junk" rated debt is somewhat doubtful.

Q. Mr. Johnson, what is Staff's view concerning when new rates should become effective?

A. It is Staff's view that the new rates should become effective no sooner than January 1, 2010.

Q. What does the Settlement Agreement provide in terms of rate stability?

A. Section II-A provides for a General Rate Case Filing Plan in which two APS base rate cases are contemplated with the scheduling and test year specifications provided for each. In Section XXII, the Agreement also provides an opportunity for APS to request a change to its base rates and/or adjustors if an emergency were to arise. An emergency is defined in the Agreement as an extraordinary event that is beyond the control of APS, and would include, for example, an imposition of a federal carbon tax or "cap and trade" system.

SECTION III – POLICY CONSIDERATIONS

Q. Mr. Johnson how does Staff reconcile moving from its recommended revenue requirement in its Direct Testimony to the revenue requirement recommended in the Settlement Agreement?

A. The testimony of Mr. Ralph Smith offers a more complete discussion of the basis for the revenue requirement set forth in the Agreement. In this testimony, I address the policy reasons underlying Staff's support for the revenue requirement set forth in the Agreement.

Q. Mr. Johnson, what was Staff's goal when it agreed to enter into settlement discussions in this matter?

A. The primary goal of Staff in this matter and all matters before the ACC is to protect the public interest, recommend rates that are just, fair and reasonable to the rate payers and the Company. Also, Staff believes that the rate payers will realize important benefits from the Agreement. In addition, Staff's desire is to apply proactive, forward thinking regulatory practices, provide regulatory support and allow the Company a timely recovery of its prudent and necessary investment. We believe we accomplished this goal by reviewing the facts presented and making appropriate recommendations to the Commission for its consideration, which properly balance both Company and rate payer interests.

Q. What were some of the major policy considerations in this Docket?

A. The major policy considerations Staff and the other Signatories dealt with to balance the diverse interests in this case included the following:

- Inclusion of additional revenue requirement to recognize post test year plant through June of 2009, 18 months beyond the test year.
- A higher return on common equity.
- A higher increment to the fair value rate of return.
- Special accounting treatment related to a Palo Verde license extension.
- APS expense reduction commitment.
- Treatment of Schedule 3 receipts as revenue for the benefit of APS.
- Limit on recovery of annual cash incentive compensation for APS executives.
- Continuation of 90/10 sharing.
- Benefits for low-income customers.
- Increased Renewable Energy commitment.
- New Demand-Side Management and Energy Efficiency requirements.
- New Rate Design Options.

Q. Can you please discuss some of the policy considerations?

A. Yes.

Post Test Year Plant

Q Can you please explain why Staff supports the inclusion of post test year plant in rate base?

A. This case must be viewed in the context of the current severe financial crisis and the Company's difficulty in maintaining investment grade bond ratings. In addition, in this instance, Staff supports the inclusion of post test year plant through June 2009, because Staff believes it will help the Company achieve a more timely recovery of its investment, since the Company has committed to make significant infrastructure investments over the next several years. The Company claims that regulatory lag would have more serious consequences given its proposed level of investment in the next few years. Staff desired to address the issue of requlatory lag through the inclusion of post test year plant as contained in the Agreement.

Cost of Capital (Common Equity)

Q. Mr. Johnson, in the Company's last rate application, what was the authorized return on common equity?

A. The Commission, in Decision No. 69663 authorized 10.75 percent return on common equity for APS.

Q. Why is Staff recommending 11 percent in this Settlement Agreement?

A. Staff acknowledges that the recommended cost of common equity is higher than that previously adopted. As discussed earlier, the rationale for such a percentage is to assist the Company in achieving a necessary level of revenues to aid APS in its effort to attract and secure access to capital markets, during this period of extraordinary financial crisis. In addition, the 11 percent is within the range as calculated by Mr. Parcell in his Direct Testimony.

APS Expense Reduction Commitment

Q. Has the Commission, in its previous decision, required APS to commit to an annual expense reduction?

A. Yes. Decision No. 70667 required APS to reduce its operational expenses by $20 million. The Agreement increases this amount by $10 million, from $20 to $30 million on average per year over the Plan Term.

Fuel and Power Supply Adjustment

Q. Did APS request the elimination of the 90/10 sharing provision in the current PSA?

A. Yes.

Q. How does the Settlement Agreement address this provision?

A. Paragraph 6.1 of the Agreement provides that the 90/10 sharing provision in the current PSA will be continued for purposes of the resolution of this rate case.

Equity Infusions

Q. Mr. Johnson, can you please briefly describe the provision Section VIII.

A. Yes, pursuant to Section VIII of the Agreement, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014. Equity infusions are an important component of this Agreement. This provision should assist the Company in maintaining investment grade financials. The Agreement also requires the Company to strive to achieve a capital structure of no more than 52% debt/total capital as calculated by the credit rating agencies by December 31, 2012.

Q. Can you please explain why this provision is important?

A. APS, in its current as well as its previous rate case, has asserted that the credit rating agencies have looked at the Company's rating in an unfavorable way. APS, in the past, has focused on its FFO to debt ratio, which it claims is a key financial metric used by the rating agencies. Staff believes if and when the Company receives the equity infusions of at least $700 million equity that are required in the Agreement, other things being equal, this should increase the FFO to debt ratio and thus help improve APS' bond ratings. In addition to the equity infusions commitment, the Agreement also provides, at paragraph 8.4, that APS shall prepare and submit a plan to the Commission and Signatories detailing the steps APS intends to take to maintain and improve its financial ratings with the credit rating agencies.

Pension and OPEB Deferrals

Q. Why did Staff agree with the Pension and OPEB expense deferrals that are provided for in Section IX of the Settlement Agreement?

A. This agreement was reached through intense negotiations, as I have described, and represents a balancing of many diverse interests. From a policy perspective, the primary reason Staff agreed to the limited deferral of APS' pension and OPEB costs in 2011 and 2012 that is provided for in Section IX of the Agreement was to provide support for APS' earnings in those years in conjunction with the General Rate Case Filing Plan that is addressed in the Agreement at Section II-A.

Q. If the Commission has specific questions about the accounting or the amounts listed in Section IX, is another Staff witness addressing such details?

A. Yes. Staff witness Ralph Smith's testimony provides additional details concerning the accounting and amounts related to this matter that are listed in the Agreement at Section IX.

Schedule 3

Q. Mr. Johnson, can you please explain the Commission's current policy as it is relates to Schedule 3.

A. Yes. Currently, Schedule 3 receipts are recorded as Contributions in Aid of Construction ("CIAC").

Q. Please explain how Staff and the Signatories proposed to treat the receipts from Schedule 3 in the Agreement.

A. Staff and the Signatories propose to treat Schedule 3 receipts as revenue to APS during the period from January 1, 2010 through either the earlier of December 31, 2012 or the conclusion of the Company's next general rate case. That is, APS would record Schedule 3 receipts as revenue (and not as CIAC) during this period.

Q. Why did Staff depart from the current Commission policy on the accounting treatment for Schedule 3 receipts?

A. As stated earlier in my testimony, the Settlement negotiation involves give and take. APS in its Application requested a rate increase in the amount of $488 million. The Agreement provides for a lower amount, and also contains a General Rate Case Filing Plan that is intended to prevent APS from immediately filing for another base rate increase. Staff's rationale for agreeing with the treatment of Schedule 3 as revenue is part of the overall framework of the Agreement and was to provide a source of additional revenues to the Company by a means other than an additional base rate increase. Having APS record Schedule 3 receipts as revenue also should improve the Company's financial metrics, such as its FFO to debt ratio, and thus should help APS improve its bond rating during the General Rate Case Filing Plan period, i.e., through December 31, 2014.

Q. Did the Agreement propose any changes to APS' Schedule 3 tariff?

A. Yes. The Agreement would result in several significant improvements to the Company's current Schedule 3 tariff. The Agreement requires APS to file a revised Schedule 3 to reflect the following modifications before the hearing in this case: 1) a clarified definition of local facilities, 2) a schedule of charges, 3) a statement that quotes provided to customers will be itemized, and 4) procedures for refunding amounts to customers when additional customers connect to the line extension.

Q. Mr. Johnson, do you believe this Agreement protects the public interest?

A. Yes, I do. As stated previously in my testimony, this Agreement strikes an appropriate balance between numerous competing interests. This balance includes the need for APS' customers to pay rates that are just and reasonable and that allow APS the opportunity to earn a reasonable return on its investment in providing electric utility services.

Q. Does this Agreement strike an appropriate balance between the diverse needs of the interested parties?

A. Yes, it does. I have discussed the many benefits to consumers beginning at page 7 of my testimony.

The Agreement also addresses and resolves all of the main rate case issues, provides sufficient revenues and return for APS to maintain reliable electric service, and results in rates and charges which Staff believes are just and reasonable. Because of these features and the others described in my testimony, from a policy perspective, Staff believes that this Agreement strikes an appropriate balance between numerous competing interests.

Low-Income Program

Q. What impact will the Settlement have on low-income customers?

A. As previously stated, the Settlement provides for no increase in base rates to low-income customers. It was the parties' intent to insulate current and future low-income customers from a base rate increase. As a result, if the Agreement is approved, low-income customers would not see a base rate increase in their utility rates, nor would they be subject to the costs associated with the Power Supply Adjustment ("PSA") and the DSM adjustor rate.

Q. Please explain other/additional benefits to low-income customers.

A. As stated in the Agreement, consistent with Decision No. 69663, APS will modify its current bill assistance program, to offer assistance to customers whose incomes exceed 150 percent of Federal Poverty Income Guidelines but are less than or equal to 200 percent.

The Plan Term established the funding level of five million dollars, to assist in the bill assistance program. The five million dollars will be funded by APS.

Additional benefits to low-income customers are set forth in Section 16.4, which provides that APS will waive the collection of additional deposits from qualifying low-income customers.

Q. As a policy matter, why should the Commission approve the Agreement?

A. The Agreement addresses and resolves all of the major rate case issues and results in rates which we believe are just and reasonable. Staff believes that the agreed-upon revenue

requirement is sufficient for APS to maintain reliable service to its customers and to provide an opportunity for APS to earn a fair return for its investors.

SECTION IV – COMMISSIONERS LETTERS

Q. Mr. Johnson are you aware that Chairman Mayes, Commissioner Pierce, Commissioner Newman, Commissioner Kennedy and Commissioner Stump all placed letters in the docket requesting that the parties address in testimony or Settlement various issues raised in the filing?

A. Yes. I have reviewed all the letters docketed by the Commissioners.

Chairman Mayes' Letters

Q. Mr. Johnson, does the Agreement address the issues raised by Chairman Mayes' letters dated January 27, 2009 and June 9, 2009?

A. Generally yes.

Q. Please explain the topics raised in these letters.

A. On January 27, 2009, Chairman Mayes in her letter expresses a view that the Commission should not address the result of any proposed settlement agreement until the Company has complied with the provision in Decision No. 70667 which called on APS to pare $20 million in operating expenses.

Q. Has the Company complied with Decision No. 70667?

A. Yes.

Q. What other topics were raised by the letter?

A. Other topics include Energy Efficiency, Renewable Energy, low-income customers, and time-of-use ("TOU").

Q. Did the Agreement address these issues?

A. Sections XIV (DSM), XV (Renewable Energy), XVI (low-income progams) and XXI (time-of-use for K-12 schools) address these issues.

Q. Mr. Johnson, can you please briefly explain those Sections.

A. Yes. Section XIV (DSM) establishes energy efficiency goals, which define an annual energy savings of 1.0% in 2010, 1.25% in 2011 and 1.5% in 2012.

Section XV requires APS to make its best effort to acquire new renewable energy resources with annual generation or saving of 1.7 million MWh to be in service by December 31, 2015.

Section XVI exempted low-income customers from the base rate increase, offers assistance for customers whose incomes exceed 150% but are less than 200% of the Federal poverty income guidelines. APS will fund this program in the amount of $5 million.

Section XXI addresses the issue of a new optional TOU rate for K-12 schools.

Q. Please list the issues in the letter dated June 9, 2009.

A. The letter covers topics including:

- Future rate cases (filing and processing)
- Return on equity

- Schedule 3
- Utility-scale solar project
- In-state wind generation
- Energy efficiency goals
- Renewable Energy Standard
- Feed-in tariff
- Carbon credits

Q. Mr. Johnson, have any of the issues listed above been addressed in your testimony or in other Staff members testimonies?

A. Yes. The following topics were addressed. Future rate case, return on equity, and Schedule 3 are all addressed in this testimony.

Barbara Keene, in her testimony, addresses utility-scale solar project, in-state wind generation, Renewable Energy Standard, and energy efficiency goals.

Commission Pierce's Letter

Q. Mr. Johnson, does the Agreement address the issue raised by Commissioner Pierce's letter dated February 9, 2009?

A. Generally yes.

Q. Please explain the issue raised in Commissioner Pierce's letter.

A. The February 9, 2009, letter covers the topic relating to low-income customers.

Q. Did the Agreement address the issues raised in the letter?

A. Yes. Section XVI of the Agreement addresses this issue. Additionally, Staff provided the following responses to Commissioner Pierce's questions.

Q. What was APS' average number of low income customers each month?
A. 47,219 (see Exhibit A attached for detail).

Q. ***What was the average and median usage (kWh per month) for these customers?***
A. *The average usage is 1.034 kWh and the median usage is 847 kWh.*

Q. ***For the ten highest use low-income customers, what was the average and median usage?***
A. *The average usage is 6,154 kWh and the median usage is 6,283 kWh.*

Q. ***For the ten lowest use low-income customers, what was the average and median usage?***
A. *The average usage is 12 kWh and the median usage is 12 kWh.*

Q. ***What was APS' average number of low income customers each month?***
A. *46,775 (see Exhibit A attached for detail).*

Q. ***What was the average and median usage (kWh per month) for these customers?***
A. *The average usage is 702 kWh and the median usage is 582 kWh.*

Q. ***For the ten highest use low-income customers, what was the average and median usage?***
A. *The average usage is 5,192 kWh and the median usage is 5,106 kWh.*

Q. ***For the ten lowest use low-income customers, what was the average and median usage?***
A. *The average usage is 15 kWh and the median usage is 14 kWh.*

Commissioner Newman's Letter

Q. Mr. Johnson, does the Agreement address the issues raised by Commissioner Newman's letter dated April 24, 2009?

A. Generally yes.

Q. Please explain.

A. The April 24, 2009, letter covers the topic of line extension policies.

Q. Did the Agreement address the item in the letter?

A. Yes. Section X of the Agreement addresses Schedule 3 (line extensions). In addition, on May 19, 2009, Staff filed in this docket a response to Commissioner Newman's letter to address the issues raised. Reproduced in this testimony are the responses to Commissioner Newman's questions.

Q. What cost would consumers incur if the Commission were to limit the free footage extension to 500 feet instead of the 1,000 feet?

A. All other things being equal, the impact on customer rates in a subsequent APS rate case would most likely be lower if a 500 foot rather than a 1,000 foot free-footage allowance was instituted, because APS' investment in the line extensions would be lower. The actual cost (impact on rates) would depend on the number of extensions in any given year. Cumulatively, the cost for these extensions out to 1,000 feet, when the free footage policy is initially borne by the utility. At the next rate case, the utility then has an opportunity to apply for recovery of the costs it paid to extend service. The utility's investment, if prudent and reasonable, is recognized in rate base and earns a return. The utility also records depreciation expense on such investment. The return on rate base and the depreciation are recognized in the context of a test year and affect rates prospectively. If the free footage were reinstated at the previous 1,000 feet, or some other level, APS (rather than the customer seeking the line extension) would be financing the amount of investment covered by the free-footage allowance. The actual costs of the line extensions to be financed by APS would not be borne by ratepayers until the conclusion of APS' next rate case.

Q. How many requests for free footage did APS receive over the last five years, by year?

A. It is Staff's understanding that APS does not track the number of requests for free footage, but does track work orders for line extensions that were made that would have fallen under the 1000-foot "free footage" provision that had previously been in effect. In response to a Staff informal data request, APS has provided the following information concerning the number of such work orders in each year:

Year	No. of Work Orders for Extensions Under 1000 Feet
2005	1,300
2006	1,783
2007	1,374
2008	419
Total	4,876

Q. How many of the requests came from out of state landowners?
A. APS has advised Staff that APS does not track requests by state of residence. Staff does not have this information.

Q. How many of the requests were from developers as opposed to homeowners?
A. APS has advised Staff that the free footage provision was not available to developers, consequently; there have been none.

<u>Commissioner Kennedy's Letters</u>

Q. Mr. Johnson, does the Agreement address the issues raised by Commissioner Kennedy's letters dated April 1, 2009 and April 29, 2009?

A. Generally yes.

Q. Please explain the issues raised in Commissioner Kennedy's April 1, 2009 letter.

A. The April 1, 2009, letter covers topics including:

a. Houses of worship tariff
b. Demand-side Management Adjustor charge in relation to houses of worship and low-income customers

Q. Did the Agreement address all of the items in the letters?

A. Yes. Section XXI.1 of the Agreement addresses the issue of houses of worship. The Agreement requires APS to unfreeze the existing rate schedule E-20 for a period of 12

months to allow for additional customer participation. Section XVI recognizes that low-income customers shall be exempt from the DSMAC.

Q. Mr. Johnson, are there other issues raised in Commissioner Kennedy's April 1, 2009 letter that were not addressed in the Agreement?

A. Yes. The Agreement did not address the issue of holding houses of worship harmless from paying the DSMAC.

Q Can you please discuss the issue raised in Commissioner Kennedy's letter dated April 29, 2009?

A. Yes, the April 29, 2009 letter raised the issue of line extension. Section X of the Agreement addresses Schedule 3 (line extension). In addition, on May 19, 2009, Staff filed in this Docket, a response to Commissioner Kennedy's letter to address the issues raised. Reproduced in this testimony are the responses to Commissioner Kennedy's letter.

Q. APS and all parties to this docket that have been affected by this line extension policy (i.e., no free footage), please provide details on exactly how this policy has negatively or positively affected you and/or the persons/entities that you represent.

A. Although Staff is not directly affected by the no-free footage policy, Staff attempts to balance the ratepayer and utility interests in the evaluation of this issue. Staff has received recent consumer complaints relating to APS' Schedule 3. Generally, these complaints fall into the categories of (1) the costs quoted appearing too high and (2) quoted costs are not itemized. See attached summaries of consumer complaints.

With respect to the utility interest, the likely effect is the possibility of a timing impact for the utility in the recovery of these costs.

Useful background information appears in the January 29, 2008 Staff Report which is attached for your convenience.

Q. APS, Utilities Division Staff ("Staff") and the Residential Utilities Consumers Office ("RUCO"), please explain how the effect of the APS' no-free-footage line extension policy is being taken into consideration in APS' pending rate case.

A. Staff is not proposing any changes to the no-free-footage policy because it is the Commission's current policy on line extensions for electric utilities. It was first adopted for APS in Decision No. 69663 and has been subsequently adopted in other electric company rate cases. Consistent with the May 4, 2009 Term Sheet under Section II(B)(3) "Treatment of Schedule 3," Staff recommends the following in APS' pending rate case:

"APS' Impact Fee proposal in the rate case would be withdrawn.

The System Facilities Charge proposed by APS shall be withdrawn.

Upon Commission approval of this settlement, APS shall file in this docket a revised Schedule 3 that is consistent with the Decision and includes clarification of charges, definitions, a schedule of charges and a requirement by APS to itemize customer quotes among other matters. In light of the Commission's continued interest in this issue, the Settlement Agreement may contain additional provisions for Schedule 3 that are revenue neutral to this settlement."

Q. APS, Staff and RUCO, please explain what benefits, if any, APS ratepayers may derive in APS' pending rate case from APS' no-free-footage line extension policy.

A. In a settlement in principle that has been reached between APS and many other parties to the rate case, APS would account for the Schedule 3 receipts as revenue (as opposed to CIAC) for a specified period. This provision is intended to help bolster APS' financial position and credit ratings and help avoid having APS immediately file another general rate case and/or another emergency rate increase request.

Q. APS, Staff and RUCO, please explain what detriments, if any, APS ratepayers may see in APS' pending rate case as a result of APS' no-free-footage line extension policy.

A. The no-free footage line extension policy can create a financial burden on new customers who no longer can avail themselves of a line extension policy that includes an allowance for free footage. The costs to individual customers of line extensions, where there is no free footage allowance, can be significant. Please see also the response to question 1 above.

Q. APS, Staff and RUCO, please explain what benefits, if any, APS ratepayers may derive in the future if APS maintains its current no-free-footage line extension policy.

A. The benefits to APS' existing ratepayers, if APS maintains its current no-free-footage line extension policy, is that costs related to growth (i.e., line extension costs) are borne to a larger extent by the new customers, who pay the higher cost

for those line extensions. The no-free-footage line extension policy was originally adopted during a time of rapid economic growth. The main reason for adopting the no-free-footage line extension policy was to have the causers of growth (new construction) pay more fully for the impacts of such growth, and to help minimize the impact of such rapid growth upon existing customers.

Ultimately, the benefit to ratepayers in the future from the current no-free-footage line extension policy is dependent upon the accounting and ratemaking treatment in a future APS rate case.

If the payments APS receives for line extensions are accounted for as revenue, and that revenue is fully recognized in the context of a future APS rate case, there would be a dollar for dollar reduction to the revenue requirement for the line extension revenue received in the test year.

If the payments APS receives for line extensions are accounted for as revenue, and that revenue is <u>not</u> recognized in the context of a future APS rate case, the benefit would inure primarily to APS and its shareholders, via increased cash flow and increased earnings, rather than to APS' ratepayers. To the extent that such increased cash flow and higher earnings assist APS in maintaining or improving its financial profile and raising its credit rating, there may be an indirect benefit experienced by ratepayers in the form of lower financing costs in a future APS rate case.

To the extent the payments APS receives for line extensions are accounted for as Contributions in Aid to Construction ("CIAC"), there would be a reduction to rate base in a future APS rate case. Additionally, as the CIAC is amortized, there would be a reduction to expenses.

A simple, illustrative single-test-year example of such impacts is as follows. Assume that in the test year in APS' next rate case, APS received $10 million in new customer payments for line extensions under 1,000 feet pursuant to the current no-free-footage line extension policy.

If this $10 million is accounted for as revenue, and that revenue is fully recognized in the test year in APS' next rate case, the revenue requirement to existing customers would be reduced by approximately $10 million.

If the $10 million were recognized as CIAC, rate base would be reduced by $10 million, less a related impact from Accumulated Deferred Income Taxes ("ADIT"), such that the net rate base deduction would be approximately $6 million. (This assumes for simplicity a combined federal and state income tax rate of 40 percent. The combined tax rate Staff used in the pending APS rate case is 39.36 percent.) In the context of that next APS rate case, the revenue requirement would be reduced by an amount that can be estimated by applying a pre-tax rate of return to the net rate base reduction, or approximately $746 thousand, plus the impact of CIAC

amortization, estimated at $333 thousand per year, assuming for simplicity a 30-year amortization period, for a total reduction to the revenue requirement of approximately $1.1 million.

The benefits (and detriments) from the revenue versus CIAC treatment vary over time. The benefit from the revenue accounting treatment is short-term and basically occurs only for rates established based on the test year in which the line extension receipts were recognized as revenue. The benefit from the CIAC accounting is cumulative and builds over time. A more detailed comparative analysis of the impact of the alternative accounting and ratemaking treatments over time, and on a net present value basis, was attached to Staff witness Ralph Smith's direct testimony as Attachment RCS-6.

In order to provide additional perspective in answering this question, we will also discuss a scenario that assumes that the current no-free-footage line extension policy was <u>not</u> in effect during the test year presumed in the above illustrative example. Under this scenario, APS (rather than the new customers) would be required to finance the $10 million of new plant represented by the line extensions that were now presumed to be covered by a free-footage allowance. Under this scenario, there would be no CIAC offset to rate base, since APS was paying for the plant additions, and existing customers would then experience a revenue requirement that was higher than the one described above in the CIAC accounting example. In other words, because the CIAC offset to rate base did not exist, APS (rather than new customers) paid for the line extension costs attributable to the free footage allowance. As a consequence, the revenue requirement to existing customers would be higher by approximately $1.1 million.

As noted above, the impact from CIAC is cumulative over time. The revenue requirement burden on existing customers from line extension costs that are not addressed by CIAC would thus be expected to grow over time.

Q. APS, Staff and RUCO, please explain what detriments, if any, APS ratepayers may see in the future if APS maintains its current no-free-footage line extension policy.

A. See response to question 4 above. In addition, the detriment that APS customers may see in the future is dependent upon the accounting and ratemaking treatment applied to line extension receipts in future APS rate cases, as explained in response to question 5. Different accounting and ratemaking treatments that could be applied to the payments APS receives for line extensions can have different short- and long-term impacts upon APS' revenue requirement in future rate cases. To the extent that APS ratepayers may experience short-term benefits related to a particular accounting and ratemaking methodology applied to receipts by APS under its current no-free-footage line extension policy, the consistent application of that method may also entail long-term detriments to APS ratepayers related to higher costs in the future.

Q. ***APS, Staff and RUCO, please explain what benefits and/or detriments, if any, APS ratepayers may see in APS' pending rate case if APS' no-free-footage line extension policy were modified in this case to allow some amount of free footage or monetary allowance. For example purposes, assume a free footage of 750 feet and a monetary allowance of $5,000.***

A. *A benefit would be realized by new customers who would pay less for a new line extension. This modification to the line extension policy would impact APS and its existing ratepayers prospectively. At some point, likely in the rates resulting from APS' next general rate case, the impacts of this policy would begin to affect current ratepayers.*

It would also affect APS' cash flow and earnings prospectively. Reinstating a free footage allowance and having a monetary allowance would be expected to reduce APS' cash flow, all other things being equal. It is unclear to what extent such a change would impact APS' credit ratings during the period between rate cases.

Q. ***APS, Staff and RUCO, please explain what benefits and/or detriments, if any, APS ratepayers may see in the future if APS' s no-free-footage line extension policy were modified in this case to allow some amount of free footage or monetary allowance. Again, for example purposes, assume a free footage of 750 feet and a monetary allowance of $5,000.***

A. *See response to question 7 above.*

<u>Commissioner Stump's Letter</u>

Q. Mr. Johnson, does the Agreement address the issues raised by Commissioner Stump's letter dated April 23, 2009?

A. Generally yes.

Q. Please explain the issues raised in Commissioner Stump's letter dated April 23, 2009.

A. The April 23, 2009, letter covers the issue of line extension policies.

Q. Did the Agreement address the item in the letter?

A. Yes. Section X of the Agreement addresses Schedule 3 (line extensions). In addition, on May 19, 2009, Staff filed in this docket a response to Commissioner Stump's letter to

address the issues raised. Reproduced in this testimony are the responses to Commissioner Stump's questions.

Q. What cost would consumers incur if the Commission were to re-instate the 1,000 foot free-line extension?

A. The actual cost (impact on rates) would depend on the number of extensions in any given year. It would also depend upon whether the related provisions of Schedule 3 were also reinstated. Cumulatively, the cost for these extensions out to 1,000 feet, when the free footage policy is in effect, is initially borne by the utility. At the next rate case, the utility then has an opportunity to apply for the costs it paid to extend service to be placed in rate base and then earn a return on and of those costs from all ratepayers. If the free footage were reinstated, APS would revert to the prior treatment of the line extensions. Under that methodology, the actual costs of the line extensions would not be borne by ratepayers until the conclusion of APS' next rate case.

Q. Should there be a cap on the amount a utility can charge the development for the extension?

A. The maximum, amount a utility should be able to charge is its actual cost for the constructing the line extension. Capping the amount that a utility could charge for extensions could lead to cross-subsidization among ratepayers. For example, in the event that a line extension cost more than the capped amount, the excess will be borne by existing ratepayers when it is placed into APS' rate base. To that extent, having a cap introduces a potential subsidization of new customers by existing customers.

Q. If a utility were to put in a line extension, is there is a benefit to all users in that extension area, including the utility and its customers?

A. It depends on how it is implemented. If the utility makes use of appropriate regional planning as part of extending new infrastructure, bringing new customers onto the system is generally a benefit to all users. New customers help to spread rate impacts. Further, new infrastructure that is implemented with regional considerations in mind should benefit the system. However, if extensions are planned with too narrow a scope, benefits may be confined to only the customer being served.

Q. If a developer were to put in the extension, would the developer be subsidizing all development which occurs later?

A. See the answer to Question 3. It would depend on the configuration of the extension and whether it was tailored only to meet the developer's immediate needs or if regional/system considerations were used.

Q. ***What policies, if any, could be put into place to re-pay the initial developer for the 1,000 foot free-line extension?***

A. *Although developers did not receive a 1,000 foot free extension under the previous version of Schedule 3, that schedule contained another provision for an economic feasibility analysis to determine the amount of free footage allowance. The economic feasibility provision allowed the possibility of refunding amounts advanced by the developer for the construction of line extension facilities. This provision of Schedule 3 was also eliminated in the last general rate case. One way to establish a means to refund the initial developer would be to revert to the old policy that was in place prior to the elimination of the economic feasibility analysis.*

Q. ***What is the average cost to a developer to put in the line extension?***

A. *The average cost to the developer is going to depend on a number of factors, including the length of the line extension, the number of homes being connected, the capability of the existing distribution backbone where the interconnection will take place, and the local geographic conditions, such as terrain, soil conditions, etc. There are several reported figures. In Docket E-01345A-05-081, in the direct testimony of David Rumolo, APS reported costs in excess of $10,000 per 1,000 feet of line-extension. In that same Docket, Mr. Rumolo also testified that the reproduction cost of the net distribution investment to serve residential customers would be approximately $2,700. This cost estimate may be low, however, as it excludes substation equipment. In the current rate case, APS has reported that its growth-related costs in 2006-2007 totaled $521 million. In that two-year time period, APS added 78,670 customers. This suggests an average cost per new customer of approximately $6,623.*

Q. ***What is the average cost to an individual homeowner to put in the line extension?***

A. *The average cost to an individual homeowner would depend on a number of factors, including the length of the line extension and the local geographic conditions, such as terrain, soil conditions, etc. In addition, see the response to question 6 above.*

Q. Mr. Johnson, do the parties believe an increased commitment to renewable energy is a ratepayer benefit that should be offered as part of the Settlement Agreement?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT
S-11
ADMITTED
ALL-STATE LEGAL®

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

TESTIMONY SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JULY 01, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 2

III. Rate Increase 2

IV. Cost of Capital and Fair Value Rate of Return 9

V. Depreciation 10

VI. Fuel and Power Supply Adjustment Provisions 11

VIII. Equity Infusions into APS 12

IX. Pension and OPEB Deferrals 13

X. Treatment of Schedule 3 14

XI. Adjustment to Depreciation Rates for Palo Verde License Extension 15

ATTACHMENTS

Calculation of Base Cost of Fuel and Purchased Power RCS-8

EXECUTIVE SUMMARY
TESTIMONY IN SUPPORT OF SETTLEMENT OF RALPH C. SMITH
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My testimony in support of the Settlement addresses the following sections of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

A summary of my testimony concerning the Settlement Agreement for each of these areas follows:

III. Rate Increase.

For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue is approximately $196.3 million, plus $11.2 million for a fuel related increase in base rates, plus $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion.

Settlement paragraph 3.8 shows how the base rate increase provided for in the Settlement compares with various Signatories' initial proposed increases. It has columns for APS's original filing, Staff's direct filing, Residential Utility Consumer Office's ("RUCO") direct filing, Arizonan for Electric Choice and Competition's ("AECC") direct filing, and the Settlement. The $344.7 million total rate increase is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

In addition to the amount of base rate increase, the Settlement Agreement also provides for exceptional accounting treatments for APS for Pension and Other Post and Employee Benefit ("OPEB") deferrals (in Section IX), for treating Schedule 3 receipts as revenue (in Section X) and for an adjustment to Palo Verde depreciation rates for a License Extension (in Section XI). Each of these special accounting provisions has future rate consequences for APS ratepayers.

IV. Cost of Capital and Fair Value Rate of Return

The Settlement Agreement at paragraphs 4.1 through 4.3 provides for an overall cost of capital of 8.58 percent and a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A. It provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Additionally, as explained on page 8 of Staff witness Johnson's direct testimony, as a matter of policy Staff proposed a fair value rate of return ("FVROR") that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB"). This 1.5 percent return was incorporated into the FVROR for Settlement Purposes, as shown on line 9 of Settlement Attachment A. As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with an additional base rate increase of $51.265 million.

V. Depreciation

Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent.

VI. Fuel and Power Supply Adjustment Provisions

Section VI of the Settlement Agreement addresses the provisions of the Purchased Power Fuel Adjustor Clause that has been agreed to by the parties through the process of negotiation. As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued. The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates. Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism. The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

VIII. Equity Infusions into APS

As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014. This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009. Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. Pension and OPEB Deferrals

Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs in 2011 and 2012 if such costs exceed the test year level, which the parties to the Settlement Agreement have identified as $23.949 million. Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

X. Treatment of Schedule 3

Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. Currently, APS records Schedule 3 receipts as Contributions in Aid to Construction ("CIAC"). As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

XI. Adjustment to Depreciation Rates for Palo Verde License Extension

Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Paragraph 11.1 also provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension.

As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. During that period, the lower recorded depreciation expense amounts mean that Accumulated Depreciation (a rate base offset) would be lower and APS' rate base in the next rate case would be higher.

As with the other aspects of the Settlement Agreement that involved compromises from Staff's normal litigation position on such issues, Staff witness Ernest Johnson is addressing the policy reasons for this treatment in the context of the Settlement Agreement.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding?

A. Yes.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-8 presents an update of Staff Schedule C-15 showing additional details for the adjustment to fuel and purchased power expense.

Q. What is the purpose of your testimony in support of the settlement?

A. The purpose of my testimony in support of the settlement is to explain the derivation of the base rate increase, some of the figures, and some of the other accounting treatments that are provided for in the Settlement. The base rate increase provided for in the Settlement is strictly for purposes of this Settlement and should not be viewed as necessarily representing positions that Staff would be advocating in any other situation. All of the Staff policy decisions related to the Settlement are addressed in the testimony of Staff witness Ernest Johnson.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your testimony?

A. My testimony addresses aspects of the following provisions of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

The numbering of these provisions in my testimony corresponds with the Settlement Agreement.

III. RATE INCREASE

Q. For Settlement purposes, to what amount of base rate increase did the signing parties agree?

A. For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue of $344.7 million is the sum of three components: (1) a non-fuel related base rate increase of approximately $196.3 million; (2) approximately $11.2 million for a fuel related increase in base rates; and (3)

approximately $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

Q. What fair value rate base and fair value rate of return did the signing parties agree to for Settlement purposes?

A. As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A.

Q. How does the amount of revenue increase provided for in the Settlement Agreement compare with what APS, Staff and other signatories had originally proposed?

A. A table shown on Settlement page 13, paragraph 3.8 (which is reproduced below for ease of reference) summarizes the base rate and total rate increase that APS, Staff, Residential Utility Consumer Office ("RUCO") and Arizonan for Electric Choice and Competition ("AECC") each had originally recommended, and shows the corresponding Settlement amounts:

Comparison of APS, Staff, RUCO and Settlement Summary of Base Rate Increase (Thousands of Dollars)	APS Proposed	Staff Proposed	RUCO Proposed	AECC Proposed	Settlement
Components of Total Rate Increase					
Base Rate Increase	$ 264,341	$ 155,062	$ (27,281)	$ 205,444	$ 196,300
Fuel Related Increase in Base Rates	$ 13,876	$ 11,436	$ 13,876	$ 10,695	$ 11,203
Total Base Rate Increase	$ 278,217	$ 166,498	$ (13,405)	$ 216,139	$ 207,503
Adjusted Base Cost of Fuel Related Increase	$ 169,977	$ 140,088	$ 169,977	$ 130,527	$ 137,235
Total Rate Increase Requested	$ 448,194	$ 306,586	$ 156,572	$ 346,666	$ 344,738
Percentage Increase Over Current Rates					
Revenue from Sales to Ultimate Retail Customers 2007 Test Year Adjusted	$ 2,637,447	$ 2,637,447	$ 2,748,697	$ 2,637,447	$ 2,637,447
Percentage Increase - Net of PSA	10.55%	6.31%	-0.49%	8.20%	7.87%
Percentage Increase - Total	16.99%	11.62%	5.70%	13.14%	13.07%
Revenue from Sales to Ultimate Retail Customers 2010 Base Rate Revenue per APS	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236
Percentage Increase - Net of PSA	10.48%	6.27%	-0.51%	8.14%	7.82%
Percentage Increase - Total	16.89%	11.55%	5.90%	13.06%	12.99%

The $344.7 million total rate increase provided for in the Settlement is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

Q. Has a portion of the amount of base rate increase provided for in the Settlement already been implemented by APS?

A. Yes. A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

Q. Referring to the above table, please explain briefly how the Settlement "base rate increase" amount of $196.3 million was derived.

A. The "base rate increase" of $196.3 million was arrived at through lengthy negotiations between the Signatories over the past 5-6 months. Staff witness Ernest Johnson's testimony in support of the Settlement explains the policy considerations involved. In dollar terms, the following presents a rough synopsis of the $196.3 million base rate

revenue increase provided for in the Settlement, starting from the recommendation in Staff's direct testimony filing:

Approximate Derivation of the $196.3 Million
(Amounts in Millions)

Line No.	Description	Revenue Requirement Amount (Decrease) Increase	Reference
1	Staff base rate revenue increase	$ **155.1**	Attachment RCS-2, Sch A, p.2, Col.B, L.9
	Supplemental:		
2	Remove APS adjustment for DSM Lost Revenue aka Uncollected Fixed Costs	$ (15.7)	R Smith Supplemental Direct filed 1-9-2009
	Corrections:		
3	Yucca Units 5 & 6	$ 1.0	Settlement Negotiations
4	Income Tax Calculation/Interest Synchronization	$ 7.4	Settlement Negotiations
	Additions:		
5	Additional Post Test Year Plant	$ 48.6	Settlement Negotiations
6	**Base rate revenue increase per Settlement**	$ **196.3**	Settlement Negotiations (sum of Lines 1-5)*

*Numbers may not add exactly due to rounding.

Q. Please briefly explain the adjustment to remove the APS adjustment for DSM Lost Revenue also know as Uncollected Fixed Costs.

A. This adjustment was addressed in my supplemental testimony, filed on January 9, 2009. APS witness Ewen's Attachment PME-13 (filed with his direct testimony) and described in his direct testimony at page 33, shows that APS had proposed to reduce test year operating revenue by $16.789 million for 220,696 MWh of lost sales, and to reduce related operating expenses by $1.052 million, for a net reduction to pre-tax operating income of $15.738 million. In Docket No. E-01345A-05-0816 et al, APS had proposed a pro forma adjustment for estimated 2006 lost revenues from DSM programs in conjunction with a test year ended September 30, 2005, i.e., approximately 1.25 years beyond the test year. In the current case, APS has proposed a pro forma adjustment for estimated 2010 lost revenue from DSM programs in conjunction with a 2007 test year,

i.e., three years beyond the test year. In Decision No. 69663, the Commission had rejected the similar adjustment proposed by APS in that rate case. As I had stated in my supplemental testimony (at page 3):

> The approximate impact from APS' proposed adjustment no. 13 to the revenue requirement is $15.7 million. ... Unless APS provides a compelling argument for this adjustment, including a strong argument why a conclusion different than Decision No. 69663 is required, Staff will reverse APS proposed adjustment no. 13 when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing.

The Settlement Agreement revenue requirement reflects this reduction of $15.7 million to reverse APS' proposed adjustment for DSM lost revenues also known as Unrecovered Fixed Charges.

Q. Please briefly explain the correction items to Staff's direct-filed revenue requirement.

A. It was brought to my attention that there were two errors in the calculation of Staff's revenue requirement. The first item related to including in jurisdictional rate base the cost of a step-up transformer for Yucca Units 5 and 6 and reflected actual costs incurred for plant balances through 12/31/08 as opposed to 09/30/08 actual costs incurred. The second item related to a correction to Staff's interest synchronization calculation for the amount "per APS' filing"[1] to take into account the interest synchronization that was reflected by the Company in each individual pro forma adjustments on APS Schedule C-2. These two corrections to Staff's revenue requirement were accepted by Staff and the other Signatories in Settlement discussions, and were reflected in deriving the amount of base rate increase that is provided for in the Settlement.

[1] See, Attachment RCS-2, Schedule C-13, line 4, as filed with my direct testimony.

Q. Please briefly explain the adjustment for additional post test year plant.

A. The additional $48.6 million represents one way of deriving an adjustment to the revenue requirement to provide rate recognition for additional APS post-test year plant additions through June 30, 2009, i.e., for a period of 18 months beyond the 2007 test year. Staff witness Ernest Johnson's testimony in support of the settlement explains the reasons for why Staff agreed to including this for purposes of deriving the amount of revenue increase provided for in the Settlement.

Q. The next item in the Settlement Agreement, paragraph 3.8, in the "Settlement" column, is $11.203 million for a "Fuel Related Increase in Base Rates." Can you please briefly explain that item?

A. Yes. This item is comparable to the $11.436 million shown in the "Staff Proposed" column.[2] When the Company's Base Cost of Fuel is reestablished in a base rate case, this impacts the amounts that APS can recover through its Power Supply Adjustor ("PSA") mechanism, which has a 90/10 sharing provision.[3] The reestablishment of a higher Base Cost of Fuel in this case allows APS to recover in base rates approximately $11.203 million more than APS would have been able to recover in increased fuel and purchased power costs solely through the operation of the PSA.

Staff's adjustment for the Base Cost of Fuel was presented on Attachment RCS-2, Schedule C-15, filed with my direct testimony. In that adjustment, Staff had used a base cost of fuel of 3.7677 cents per kWh. The Settlement Agreement (at paragraph 6.2) provides for a slightly lower Base Cost of Fuel of 3.7571 cents per kWh. This difference in the Base Cost of Fuel is attributed to the decrease of approximately $233,000 from the

[2] This amount also appears on Attachment RCS-2 (to my direct testimony), Schedule A, page 1, line 9, and page 2, line 10.

[3] Per Settlement Agreement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued for purposes of the resolution of this rate case.

$11.436 million in Staff's direct filing to the $11.203 million provided for in the Settlement.

Q. Have you prepared an update to Staff Schedule C-15 that shows this?

A. Yes. Attachment RCS-8 to my testimony in support of the Settlement updates Staff Schedule C-15, and includes some additional calculation detail, showing the derivation of the $11.203 million Settlement amount and the $11.436 million amount from Staff's direct filing.

Q. Please briefly explain the "Adjusted Base Cost of Fuel Related Increase" of $137.235 million that appears in the Settlement Agreement, paragraph 3.8 table.

A. The $137.235 million represents the amount of fuel and purchased power cost increase that is now to be included in APS' base rates, at the Base Cost of Fuel of 3.7571 cents per kWh. Were it not for the base rate case, APS would have recovered this amount of fuel and purchased power cost increase through the operation of its PSA. The derivation of the $137.235 million is also shown on Attachment RCS-8.

Q. What average percentage increase in base rates does the revenue increase of $344.738 million represent?

A. As shown in the Settlement Agreement at paragraph 3.8, this represents an average increase of approximately 13.07 percent over the adjusted 2007 test year base rate revenue.

Q. Are there other provisions in the Settlement Agreement that would result in future rate increases to APS customers?

A. Yes. As described in the Settlement at paragraph 3.9, APS has various adjustor mechanisms, which are estimated to produce net additional rate increases. Staff witness Barbara Keene's testimony in support of the settlement addresses those mechanisms. Additionally, as described in the Settlement at paragraph 3.10, there are other provisions of the Settlement which do not have a rate impact in the present case, but will have an impact in future APS rate cases. I address some of those items in subsequent sections of my testimony in support of the Settlement.

IV. COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. Please refer to paragraphs 4.1 and 4.2 of the Settlement Agreement. What is the source for the capital structure and cost rates?

A. The source for the capital structure and cost rates specified in paragraphs 4.1 and 4.2 of the Settlement Agreement is the agreement of the Signatories. These amounts can also be found in Staff's direct filing at Attachment RCS-2, Schedule D, lines 5-8, and produce a weighted cost of capital of 8.58 percent.

The Settlement Agreement provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Q. Please refer to paragraph 4.3 of the Settlement Agreement. How was the 6.65 percent calculated?

A. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR"), which is calculated as shown on Settlement Attachment A.

As explained on page 8 of Staff witness Johnson's direct testimony, as a policy decision in this case, Staff had proposed a revenue requirement for APS using a FVROR that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB").

As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with a base rate increase of $51.265 million that was in addition to the OCRB-based calculation. This 1.5 percent return was also incorporated into the FVROR for Settlement Purposes, as shown on line 9, of Settlement Attachment A.

V. DEPRECIATION

Q. Please address the depreciation rates provided for in the Settlement Agreement at Section V.

A. Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent. This treatment is consistent with the recommendations made concerning depreciation rates in the Staff direct filing.

VI. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

Q. Please address the Fuel and Power Supply Adjustment provisions provided for in the Settlement Agreement at Section VI.

A. Section VI of the Settlement Agreement addresses the provisions of the PSA that have been agreed to by the Signatories through the process of negotiation.

As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued.

The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates.

Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism.

The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

Q. How does the Base Cost of Fuel and Purchased Power of 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 compare with APS' and Staff's direct filings?

A. The 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 corresponds to the forward-looking PSA rate currently in effect for APS. It is lower than both the 3.8783 cents per kWh used by APS in its direct filing and the 3.7677 cents per kWh from Staff's direct filing. It thus reflects, at least in part, the lower cost of fuel that APS has been experiencing recently.

Paragraph 2.6 of the Settlement Agreement provides for the possibility of an accelerated PSA reset at the time new base rates are implemented if APS's fuel and purchased power costs result in a PSA over-collected balance at that time.

Q. Please explain the Settlement treatment of the Gain on Sale of SO_2 Allowances.

A. The Settlement Agreement at paragraph 6.3 provides that Gains on SO_2 Allowance sales over or under the normalized jurisdictional test year amount shall be recovered and/or refunded through the PSA mechanism.

Staff's derivation of the proposed revenue increase had reflected a normalized amount of Gains on the Sale of SO_2 Allowances of approximately $7.045 million as an offset to the test year expenses[4] (which in turn reduced the amount of the base rate revenue increase). Staff's recommendation was also that annual fluctuations above or below the amounts reflected in base rates for Gains on the Sale of SO_2 Allowances should be reflected as adjustments to PSA-includable costs. The Settlement provides for 100 percent of the annual Gains on the Sale of SO_2 Allowances to be credited in the PSA against PSA includable costs. Crediting such gains through the PSA is appropriate and reasonable because Gains on the Sale of SO_2 Emission Allowances are closely related to the amount of coal burned at APS's generating plants, can be significant in amount, and can fluctuate significantly from year to year.

VIII. EQUITY INFUSIONS INTO APS

Q. Please discuss the Settlement provisions for equity infusions into APS.

A. As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014.

[4] See Attachment RCS-2, Schedule C-14, Column B, line 1, as filed with my direct testimony.

This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009.

Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. PENSION AND OPEB DEFERRALS

Q. Please discuss the Settlement provisions for Pension and Other Post Employment Benefit ("OPEB") deferrals.

A. Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs by APS in 2011 and 2012 if such costs exceed the test year level, which the Signatories to the Settlement Agreement have identified as $23.949 million.

Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. The total additional cost to ratepayers from this provision could be as much as $42.5 million (if the maximum deferrals in 2011 of $13.5 million and 2012 of $29 million occur).

The annual impact to APS ratepayers would depend upon the amortization period selected in a future APS next rate case. For illustrative purposes, if a five-year amortization period were to be used, and the deferrals reached the maximum amount of $42.5 million, the annual impact on APS ratepayers would be approximately $8.5 million of additional rate increase per year.[5] If a seven-year amortization period were to be used, the annual impact

[5] $42.5 million / 5 years

on APS ratepayers would be approximately $6.1 million of additional rate increase per year.[6]

Another witness for Staff, Ernest Johnson, is addressing the policy reasons for why Staff has agreed to provide APS with the deferred accounting treatment.

X. TREATMENT OF SCHEDULE 3

Q. How does APS currently account for Schedule 3 receipts?

A. Currently, APS records Schedule 3 receipts as Contributions in Aid of Construction ("CIAC").

Q. How is CIAC typically treated for ratemaking purposes?

A. CIAC is typically treated for ratemaking purposes as an offset to rate base. The rate base offset amount related to CIAC is typically based on the unamortized CIAC balance, less an income tax impact that is accounted for in the balance of Accumulated Deferred Income Taxes ("ADIT").

As a simplified example, if a utility had $100 million of unamortized CIAC (and there was a 40 percent combined state and federal income tax rate), rate base would be reduced by approximately $60 million ($100 million of CIAC less $40 million of ADIT).

The amortization of CIAC is typically reflected for ratemaking purposes as an offset to a utility's depreciation expense.

[6] $42.5 million / 7 years

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Does accounting for Schedule 3 receipts as revenue during this period have future rate consequences?

A. Yes. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment.

Q. Is it possible to estimate the increased rate base, post-2012, that would result from APS' accounting for Schedule 3 receipts as revenue during the period, 2010 through 2012?

A. Not reliably. The amounts identified by APS for 2010-2012 sum to $97 million. The rate base increase would be approximately the sum of the Schedule 3 amounts for 2010-2012 that APS accounted for as revenue, rather than as CIAC, less the related ADIT impact.

XI. ADJUSTMENT TO DEPRECIATION RATES FOR PALO VERDE LICENSE EXTENSION

Q. Has APS applied for a Palo Verde license extension?

A. Yes. APS has applied for a license extension for the Palo Verde nuclear generating plant.

Q. How would APS' depreciation rates be impacted by a Palo Verde license extension?

A. The cost of the plant is being depreciated over the remaining period of the license. With a license extension, the remaining cost of the plant would be depreciated over a significantly longer period, and the result would be significantly lower depreciation rates.

Q. Where are the anticipated new depreciation rates related to a Palo Verde life extension specified in the Settlement Agreement?

A. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Q. Are the new depreciation rates related to a Palo Verde life extension significantly lower than the present Palo Verde depreciation rates?

A. Yes. Referring to Settlement Agreement Attachment B, for example, at page 5 of 8, APS' current depreciation rate for Palo Verde, on a composite basis, is 2.80 percent. With a license extension, the Palo Verde composite depreciation rate[7] would drop to 1.36 percent. In other words, the composite depreciation rate for Palo Verde in total would be cut by more than half, as a result of reflecting the impact of the license extension.

Q. How is the implementation of new depreciation rates by a utility typically coordinated with the ratemaking process?

A. Typically, the implementation of new depreciation rates is coordinated with the ratemaking process by having new depreciation rates be implemented at the same time that a utility's new base rates become effective.

Q. Why is that coordination of new depreciation rates in the ratemaking process usually considered important?

A. Depreciation expense is a significant component of a utility's cost of service. Coordinating the implementation of new depreciation rates, especially where the new rates represent significant changes from the existing rates, with changes in the utility's base

[7] As shown in the Settlement Agreement, Attachment B, APS does not apply depreciation rates for its generating units on a composite basis; rather, APS applies such depreciation rates by unit and by type of plant.

rates for utility service helps assure that the Depreciation Expense and Accumulated Depreciation that the utility records on its books is coordinated with the rates that ratepayers are paying for utility service. Accumulated Depreciation is a significant offset to a utility's rate base.

Q. How does the Settlement Agreement provide for the implementation by APS of new, significantly lower depreciation rates related to a Palo Verde life extension?

A. Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012.

Q. How is this provision intended to benefit APS?

A. As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. APS' reported earnings would be improved by recording lower depreciation expense for some period before the lower depreciation expense is recognized in the establishment of customer rates for electric service.

Q. How could this provision in the Settlement result in higher future costs to APS' ratepayers?

A. It could result in a higher rate base from a lower amount of Accumulated Depreciation compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect. Specifically, APS would be recording

lower Palo Verde Depreciation Expense before lower recorded depreciation expense amounts are recognized in the ratemaking process. During that period, the amount of Accumulated Depreciation (a rate base offset) recorded by APS would be lower and, consequently, APS' rate base in a future rate case (or cases) would be higher than compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect.

Q. When would APS ratepayers start to benefit from the lower Palo Verde depreciation expense?

A. Ratepayers would start to benefit from the lower Palo Verde depreciation expenses once APS' base rates were adjusted in a future rate case to reflect the impact of this reduced expense.

Q. Would a Palo Verde life extension affect any other expenses?

A. Yes. Other things being equal, a Palo Verde life extension would also be expected to significantly reduce APS' nuclear decommissioning expense.

Q. How does the Settlement Agreement provide for recognizing the impact of decreased decommissioning expense?

A. The Settlement Agreement at paragraph 11.1 provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension. Moreover, it is the Signatories' intention that the reduction in decommissioning expense be passed onto APS' ratepayers, via a reduction to the SBC, concurrently with when APS begins to record the lower Palo Verde depreciation expense on its books.

Q. Does this conclude your Testimony?

A. Yes, it does.

Arizona Public Service Company
Base Fuel and Purchased Power

Test Year Ended December 31, 2007

Attachment RCS-8
Docket No. E-01345A-08-0172
Schedule C-15
Page 1 of 1

UPDATED FOR SETTLEMENT

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)	Reference
1	Adjustment to Base Fuel and Purchased Power	$ (32,317,378)	$ (32,317,378)	A
1a	**PER SETTLEMENT**	**$ (35,425,907)**	**$ (35,425,907)**	
1b	Difference	$ (3,108,529)	$ (3,108,529)	

Notes and Source

A: Per APS Witness Ewen Attachment PME-3 and APS' supplemental response to Staff ___

	Adjusted Test Year Fuel and Purchased Power Costs (cents per kWh)	Per APS	Per Staff	Adjustment
2	Normalized Fuel and Purchased Costs	3.8783	3.7677	
3	Test Year Fuel and Purchased Power Costs	3.4346	3.4346	
4	Difference	0.4437	0.3331	
	Adjusted Test Year Retail Sales (MWh)			
5	Test Year Retail Sales (MWh)	29,171,321,000	29,171,321,000	
6	Pro Forma Adjustment to Normalize Weather	(445,396,000)	(445,396,000)	
7	Pro Forma Adjustment to Annualize 12/31/07 Customer Level	494,127,000	494,127,000	
8	Adjusted Test Year Retail Sales	29,220,052,000	29,220,052,000	
9	Pro Forma Adjustment to Fuel and Purchased Power Expense	$ 129,649,371	$ 97,331,993	$ (32,317,378)

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			Per Staff Direct Filing		
10	Normalized Fuel and Purchased Costs	3.8783	3.7677		
11	Existing base fuel rate	3.2491	3.2491		
12	Increase above current base cost of fuel	0.6292	0.5186		($000)
13	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 151,535,190	$ (32,328,581)	$(32,329)
14	Related reduction in PSA revenue	$ 169,987,454	$ 140,098,732	$ (29,888,722)	$(29,889)
15	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,436,458	$ (2,439,859)	$ (2,440)
16	Rounded to thousands	$ 13,876	$ 11,436	$ (2,440)	

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			PER SETTLEMENT		
17	Related reduction in PSA revenue	169,987,454.0000	3.7571	**Per APS's PSA filing**	
18	Existing base fuel rate	3.2491	3.2491		
19	Increase above current base cost of fuel	169,987,450.7509	0.5080		($000)
20	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 148,437,864	$ (35,425,907)	$(35,426)
21	Related reduction in PSA revenue	$ 169,987,454	$ 137,235,163	$ (32,752,291)	$(32,752)
22	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,202,701	$ (2,673,616)	$ (2,674)
23	Rounded to thousands	$ 13,876	$ 11,203	$ (2,673)	
24	Difference from Staff direct filing		$ (233)	$ (233)	

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

TESTIMONY SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JULY 01, 2009

TABLE OF CONTENTS

		Page
INTRODUCTION		1
DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS		2
III.	Rate Increase	2
IV.	Cost of Capital and Fair Value Rate of Return	9
V.	Depreciation	10
VI.	Fuel and Power Supply Adjustment Provisions	11
VIII.	Equity Infusions into APS	12
IX.	Pension and OPEB Deferrals	13
X.	Treatment of Schedule 3	14
XI.	Adjustment to Depreciation Rates for Palo Verde License Extension	15

ATTACHMENTS

Calculation of Base Cost of Fuel and Purchased Power RCS-8

EXECUTIVE SUMMARY
TESTIMONY IN SUPPORT OF SETTLEMENT OF RALPH C. SMITH
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My testimony in support of the Settlement addresses the following sections of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

A summary of my testimony concerning the Settlement Agreement for each of these areas follows:

III. Rate Increase.

For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue is approximately $196.3 million, plus $11.2 million for a fuel related increase in base rates, plus $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion.

Settlement paragraph 3.8 shows how the base rate increase provided for in the Settlement compares with various Signatories' initial proposed increases. It has columns for APS's original filing, Staff's direct filing, Residential Utility Consumer Office's ("RUCO") direct filing, Arizonan for Electric Choice and Competition's ("AECC") direct filing, and the Settlement. The $344.7 million total rate increase is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

In addition to the amount of base rate increase, the Settlement Agreement also provides for exceptional accounting treatments for APS for Pension and Other Post and Employee Benefit ("OPEB") deferrals (in Section IX), for treating Schedule 3 receipts as revenue (in Section X) and for an adjustment to Palo Verde depreciation rates for a License Extension (in Section XI). Each of these special accounting provisions has future rate consequences for APS ratepayers.

IV. Cost of Capital and Fair Value Rate of Return

The Settlement Agreement at paragraphs 4.1 through 4.3 provides for an overall cost of capital of 8.58 percent and a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A. It provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Additionally, as explained on page 8 of Staff witness Johnson's direct testimony, as a matter of policy Staff proposed a fair value rate of return ("FVROR") that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB"). This 1.5 percent return was incorporated into the FVROR for Settlement Purposes, as shown on line 9 of Settlement Attachment A. As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with an additional base rate increase of $51.265 million.

V. Depreciation

Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent.

VI. Fuel and Power Supply Adjustment Provisions

Section VI of the Settlement Agreement addresses the provisions of the Purchased Power Fuel Adjustor Clause that has been agreed to by the parties through the process of negotiation. As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued. The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates. Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism. The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

VIII. Equity Infusions into APS

As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014. This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009. Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. Pension and OPEB Deferrals

Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs in 2011 and 2012 if such costs exceed the test year level, which the parties to the Settlement Agreement have identified as $23.949 million. Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

X. Treatment of Schedule 3

Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. Currently, APS records Schedule 3 receipts as Contributions in Aid to Construction ("CIAC"). As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

XI. Adjustment to Depreciation Rates for Palo Verde License Extension

Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Paragraph 11.1 also provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension.

As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. During that period, the lower recorded depreciation expense amounts mean that Accumulated Depreciation (a rate base offset) would be lower and APS' rate base in the next rate case would be higher.

As with the other aspects of the Settlement Agreement that involved compromises from Staff's normal litigation position on such issues, Staff witness Ernest Johnson is addressing the policy reasons for this treatment in the context of the Settlement Agreement.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding?

A. Yes.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-8 presents an update of Staff Schedule C-15 showing additional details for the adjustment to fuel and purchased power expense.

Q. What is the purpose of your testimony in support of the settlement?

A. The purpose of my testimony in support of the settlement is to explain the derivation of the base rate increase, some of the figures, and some of the other accounting treatments that are provided for in the Settlement. The base rate increase provided for in the Settlement is strictly for purposes of this Settlement and should not be viewed as necessarily representing positions that Staff would be advocating in any other situation. All of the Staff policy decisions related to the Settlement are addressed in the testimony of Staff witness Ernest Johnson.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your testimony?

A. My testimony addresses aspects of the following provisions of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

The numbering of these provisions in my testimony corresponds with the Settlement Agreement.

III. RATE INCREASE

Q. For Settlement purposes, to what amount of base rate increase did the signing parties agree?

A. For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue of $344.7 million is the sum of three components: (1) a non-fuel related base rate increase of approximately $196.3 million; (2) approximately $11.2 million for a fuel related increase in base rates; and (3)

approximately $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

Q. What fair value rate base and fair value rate of return did the signing parties agree to for Settlement purposes?

A. As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A.

Q. How does the amount of revenue increase provided for in the Settlement Agreement compare with what APS, Staff and other signatories had originally proposed?

A. A table shown on Settlement page 13, paragraph 3.8 (which is reproduced below for ease of reference) summarizes the base rate and total rate increase that APS, Staff, Residential Utility Consumer Office ("RUCO") and Arizonan for Electric Choice and Competition ("AECC") each had originally recommended, and shows the corresponding Settlement amounts:

Comparison of APS, Staff, RUCO and Settlement Summary of Base Rate Increase (Thousands of Dollars)	APS Proposed	Staff Proposed	RUCO Proposed	AECC Proposed	Settlement
Components of Total Rate Increase					
Base Rate Increase	$ 264,341	$ 155,062	$ (27,281)	$ 205,444	$ 196,300
Fuel Related Increase in Base Rates	$ 13,876	$ 11,436	$ 13,876	$ 10,695	$ 11,203
Total Base Rate Increase	$ 278,217	$ 166,498	$ (13,405)	$ 216,139	$ 207,503
Adjusted Base Cost of Fuel Related Increase	$ 169,977	$ 140,088	$ 169,977	$ 130,527	$ 137,235
Total Rate Increase Requested	$ 448,194	$ 306,586	$ 156,572	$ 346,666	$ 344,738
Percentage Increase Over Current Rates					
Revenue from Sales to Ultimate Retail Customers					
2007 Test Year Adjusted	$ 2,637,447	$ 2,637,447	$ 2,748,697	$ 2,637,447	$ 2,637,447
Percentage Increase - Net of PSA	10.55%	6.31%	-0.49%	8.20%	7.87%
Percentage Increase - Total	16.99%	11.62%	5.70%	13.14%	13.07%
Revenue from Sales to Ultimate Retail Customers					
2010 Base Rate Revenue per APS	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236
Percentage Increase - Net of PSA	10.48%	6.27%	-0.51%	8.14%	7.82%
Percentage Increase - Total	16.89%	11.55%	5.90%	13.06%	12.99%

The $344.7 million total rate increase provided for in the Settlement is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

Q. Has a portion of the amount of base rate increase provided for in the Settlement already been implemented by APS?

A. Yes. A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

Q. Referring to the above table, please explain briefly how the Settlement "base rate increase" amount of $196.3 million was derived.

A. The "base rate increase" of $196.3 million was arrived at through lengthy negotiations between the Signatories over the past 5-6 months. Staff witness Ernest Johnson's testimony in support of the Settlement explains the policy considerations involved. In dollar terms, the following presents a rough synopsis of the $196.3 million base rate

revenue increase provided for in the Settlement, starting from the recommendation in Staff's direct testimony filing:

Approximate Derivation of the $196.3 Million
(Amounts in Millions)

Line No.	Description	Revenue Requirement Amount (Decrease) Increase	Reference
1	Staff base rate revenue increase	$ 155.1	Attachment RCS-2, Sch A, p.2, Col.B, L.9
	Supplemental:		
2	Remove APS adjustment for DSM Lost Revenue aka Uncollected Fixed Costs	$ (15.7)	R Smith Supplemental Direct filed 1-9-2009
	Corrections:		
3	Yucca Units 5 & 6	$ 1.0	Settlement Negotiations
4	Income Tax Calculation/Interest Synchronization	$ 7.4	Settlement Negotiations
	Additions:		
5	Additional Post Test Year Plant	$ 48.6	Settlement Negotiations
6	**Base rate revenue increase per Settlement**	**$ 196.3**	Settlement Negotiations (sum of Lines 1-5)*

*Numbers may not add exactly due to rounding.

Q. Please briefly explain the adjustment to remove the APS adjustment for DSM Lost Revenue also know as Uncollected Fixed Costs.

A. This adjustment was addressed in my supplemental testimony, filed on January 9, 2009. APS witness Ewen's Attachment PME-13 (filed with his direct testimony) and described in his direct testimony at page 33, shows that APS had proposed to reduce test year operating revenue by $16.789 million for 220,696 MWh of lost sales, and to reduce related operating expenses by $1.052 million, for a net reduction to pre-tax operating income of $15.738 million. In Docket No. E-01345A-05-0816 et al, APS had proposed a pro forma adjustment for estimated 2006 lost revenues from DSM programs in conjunction with a test year ended September 30, 2005, i.e., approximately 1.25 years beyond the test year. In the current case, APS has proposed a pro forma adjustment for estimated 2010 lost revenue from DSM programs in conjunction with a 2007 test year,

i.e., three years beyond the test year. In Decision No. 69663, the Commission had rejected the similar adjustment proposed by APS in that rate case. As I had stated in my supplemental testimony (at page 3):

> The approximate impact from APS' proposed adjustment no. 13 to the revenue requirement is $15.7 million. ... Unless APS provides a compelling argument for this adjustment, including a strong argument why a conclusion different than Decision No. 69663 is required, Staff will reverse APS proposed adjustment no. 13 when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing.

The Settlement Agreement revenue requirement reflects this reduction of $15.7 million to reverse APS' proposed adjustment for DSM lost revenues also known as Unrecovered Fixed Charges.

Q. Please briefly explain the correction items to Staff's direct-filed revenue requirement.

A. It was brought to my attention that there were two errors in the calculation of Staff's revenue requirement. The first item related to including in jurisdictional rate base the cost of a step-up transformer for Yucca Units 5 and 6 and reflected actual costs incurred for plant balances through 12/31/08 as opposed to 09/30/08 actual costs incurred. The second item related to a correction to Staff's interest synchronization calculation for the amount "per APS' filing"[1] to take into account the interest synchronization that was reflected by the Company in each individual pro forma adjustments on APS Schedule C-2. These two corrections to Staff's revenue requirement were accepted by Staff and the other Signatories in Settlement discussions, and were reflected in deriving the amount of base rate increase that is provided for in the Settlement.

[1] See, Attachment RCS-2, Schedule C-13, line 4, as filed with my direct testimony.

Q. Please briefly explain the adjustment for additional post test year plant.

A. The additional $48.6 million represents one way of deriving an adjustment to the revenue requirement to provide rate recognition for additional APS post-test year plant additions through June 30, 2009, i.e., for a period of 18 months beyond the 2007 test year. Staff witness Ernest Johnson's testimony in support of the settlement explains the reasons for why Staff agreed to including this for purposes of deriving the amount of revenue increase provided for in the Settlement.

Q. The next item in the Settlement Agreement, paragraph 3.8, in the "Settlement" column, is $11.203 million for a "Fuel Related Increase in Base Rates." Can you please briefly explain that item?

A. Yes. This item is comparable to the $11.436 million shown in the "Staff Proposed" column.[2] When the Company's Base Cost of Fuel is reestablished in a base rate case, this impacts the amounts that APS can recover through its Power Supply Adjustor ("PSA") mechanism, which has a 90/10 sharing provision.[3] The reestablishment of a higher Base Cost of Fuel in this case allows APS to recover in base rates approximately $11.203 million more than APS would have been able to recover in increased fuel and purchased power costs solely through the operation of the PSA.

Staff's adjustment for the Base Cost of Fuel was presented on Attachment RCS-2, Schedule C-15, filed with my direct testimony. In that adjustment, Staff had used a base cost of fuel of 3.7677 cents per kWh. The Settlement Agreement (at paragraph 6.2) provides for a slightly lower Base Cost of Fuel of 3.7571 cents per kWh. This difference in the Base Cost of Fuel is attributed to the decrease of approximately $233,000 from the

[2] This amount also appears on Attachment RCS-2 (to my direct testimony), Schedule A, page 1, line 9, and page 2, line 10.

[3] Per Settlement Agreement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued for purposes of the resolution of this rate case.

$11.436 million in Staff's direct filing to the $11.203 million provided for in the Settlement.

Q. Have you prepared an update to Staff Schedule C-15 that shows this?

A. Yes. Attachment RCS-8 to my testimony in support of the Settlement updates Staff Schedule C-15, and includes some additional calculation detail, showing the derivation of the $11.203 million Settlement amount and the $11.436 million amount from Staff's direct filing.

Q. Please briefly explain the "Adjusted Base Cost of Fuel Related Increase" of $137.235 million that appears in the Settlement Agreement, paragraph 3.8 table.

A. The $137.235 million represents the amount of fuel and purchased power cost increase that is now to be included in APS' base rates, at the Base Cost of Fuel of 3.7571 cents per kWh. Were it not for the base rate case, APS would have recovered this amount of fuel and purchased power cost increase through the operation of its PSA. The derivation of the $137.235 million is also shown on Attachment RCS-8.

Q. What average percentage increase in base rates does the revenue increase of $344.738 million represent?

A. As shown in the Settlement Agreement at paragraph 3.8, this represents an average increase of approximately 13.07 percent over the adjusted 2007 test year base rate revenue.

Q. Are there other provisions in the Settlement Agreement that would result in future rate increases to APS customers?

A. Yes. As described in the Settlement at paragraph 3.9, APS has various adjustor mechanisms, which are estimated to produce net additional rate increases. Staff witness Barbara Keene's testimony in support of the settlement addresses those mechanisms. Additionally, as described in the Settlement at paragraph 3.10, there are other provisions of the Settlement which do not have a rate impact in the present case, but will have an impact in future APS rate cases. I address some of those items in subsequent sections of my testimony in support of the Settlement.

IV. COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. Please refer to paragraphs 4.1 and 4.2 of the Settlement Agreement. What is the source for the capital structure and cost rates?

A. The source for the capital structure and cost rates specified in paragraphs 4.1 and 4.2 of the Settlement Agreement is the agreement of the Signatories. These amounts can also be found in Staff's direct filing at Attachment RCS-2, Schedule D, lines 5-8, and produce a weighted cost of capital of 8.58 percent.

The Settlement Agreement provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Q. Please refer to paragraph 4.3 of the Settlement Agreement. How was the 6.65 percent calculated?

A. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR"), which is calculated as shown on Settlement Attachment A.

As explained on page 8 of Staff witness Johnson's direct testimony, as a policy decision in this case, Staff had proposed a revenue requirement for APS using a FVROR that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB").

As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with a base rate increase of $51.265 million that was in addition to the OCRB-based calculation. This 1.5 percent return was also incorporated into the FVROR for Settlement Purposes, as shown on line 9, of Settlement Attachment A.

V. DEPRECIATION

Q. Please address the depreciation rates provided for in the Settlement Agreement at Section V.

A. Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent. This treatment is consistent with the recommendations made concerning depreciation rates in the Staff direct filing.

VI. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

Q. Please address the Fuel and Power Supply Adjustment provisions provided for in the Settlement Agreement at Section VI.

A. Section VI of the Settlement Agreement addresses the provisions of the PSA that have been agreed to by the Signatories through the process of negotiation.

As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued.

The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates.

Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism.

The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

Q. How does the Base Cost of Fuel and Purchased Power of 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 compare with APS' and Staff's direct filings?

A. The 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 corresponds to the forward-looking PSA rate currently in effect for APS. It is lower than both the 3.8783 cents per kWh used by APS in its direct filing and the 3.7677 cents per kWh from Staff's direct filing. It thus reflects, at least in part, the lower cost of fuel that APS has been experiencing recently.

Paragraph 2.6 of the Settlement Agreement provides for the possibility of an accelerated PSA reset at the time new base rates are implemented if APS's fuel and purchased power costs result in a PSA over-collected balance at that time.

Q. Please explain the Settlement treatment of the Gain on Sale of SO_2 Allowances.

A. The Settlement Agreement at paragraph 6.3 provides that Gains on SO_2 Allowance sales over or under the normalized jurisdictional test year amount shall be recovered and/or refunded through the PSA mechanism.

Staff's derivation of the proposed revenue increase had reflected a normalized amount of Gains on the Sale of SO_2 Allowances of approximately $7.045 million as an offset to the test year expenses[4] (which in turn reduced the amount of the base rate revenue increase). Staff's recommendation was also that annual fluctuations above or below the amounts reflected in base rates for Gains on the Sale of SO_2 Allowances should be reflected as adjustments to PSA-includable costs. The Settlement provides for 100 percent of the annual Gains on the Sale of SO_2 Allowances to be credited in the PSA against PSA includable costs. Crediting such gains through the PSA is appropriate and reasonable because Gains on the Sale of SO_2 Emission Allowances are closely related to the amount of coal burned at APS's generating plants, can be significant in amount, and can fluctuate significantly from year to year.

VIII. EQUITY INFUSIONS INTO APS

Q. Please discuss the Settlement provisions for equity infusions into APS.

A. As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014.

[4] See Attachment RCS-2, Schedule C-14, Column B, line 1, as filed with my direct testimony.

This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009.

Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. PENSION AND OPEB DEFERRALS

Q. Please discuss the Settlement provisions for Pension and Other Post Employment Benefit ("OPEB") deferrals.

A. Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs by APS in 2011 and 2012 if such costs exceed the test year level, which the Signatories to the Settlement Agreement have identified as $23.949 million.

Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. The total additional cost to ratepayers from this provision could be as much as $42.5 million (if the maximum deferrals in 2011 of $13.5 million and 2012 of $29 million occur).

The annual impact to APS ratepayers would depend upon the amortization period selected in a future APS next rate case. For illustrative purposes, if a five-year amortization period were to be used, and the deferrals reached the maximum amount of $42.5 million, the annual impact on APS ratepayers would be approximately $8.5 million of additional rate increase per year.[5] If a seven-year amortization period were to be used, the annual impact

[5] $42.5 million / 5 years

on APS ratepayers would be approximately $6.1 million of additional rate increase per year.[6]

Another witness for Staff, Ernest Johnson, is addressing the policy reasons for why Staff has agreed to provide APS with the deferred accounting treatment.

X. TREATMENT OF SCHEDULE 3

Q. How does APS currently account for Schedule 3 receipts?

A. Currently, APS records Schedule 3 receipts as Contributions in Aid of Construction ("CIAC").

Q. How is CIAC typically treated for ratemaking purposes?

A. CIAC is typically treated for ratemaking purposes as an offset to rate base. The rate base offset amount related to CIAC is typically based on the unamortized CIAC balance, less an income tax impact that is accounted for in the balance of Accumulated Deferred Income Taxes ("ADIT").

As a simplified example, if a utility had $100 million of unamortized CIAC (and there was a 40 percent combined state and federal income tax rate), rate base would be reduced by approximately $60 million ($100 million of CIAC less $40 million of ADIT).

The amortization of CIAC is typically reflected for ratemaking purposes as an offset to a utility's depreciation expense.

[6] $42.5 million / 7 years

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Does accounting for Schedule 3 receipts as revenue during this period have future rate consequences?

A. Yes. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment.

Q. Is it possible to estimate the increased rate base, post-2012, that would result from APS' accounting for Schedule 3 receipts as revenue during the period, 2010 through 2012?

A. Not reliably. The amounts identified by APS for 2010-2012 sum to $97 million. The rate base increase would be approximately the sum of the Schedule 3 amounts for 2010-2012 that APS accounted for as revenue, rather than as CIAC, less the related ADIT impact.

XI. ADJUSTMENT TO DEPRECIATION RATES FOR PALO VERDE LICENSE EXTENSION

Q. Has APS applied for a Palo Verde license extension?

A. Yes. APS has applied for a license extension for the Palo Verde nuclear generating plant.

Q. How would APS' depreciation rates be impacted by a Palo Verde license extension?

A. The cost of the plant is being depreciated over the remaining period of the license. With a license extension, the remaining cost of the plant would be depreciated over a significantly longer period, and the result would be significantly lower depreciation rates.

Q. Where are the anticipated new depreciation rates related to a Palo Verde life extension specified in the Settlement Agreement?

A. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Q. Are the new depreciation rates related to a Palo Verde life extension significantly lower than the present Palo Verde depreciation rates?

A. Yes. Referring to Settlement Agreement Attachment B, for example, at page 5 of 8, APS' current depreciation rate for Palo Verde, on a composite basis, is 2.80 percent. With a license extension, the Palo Verde composite depreciation rate[7] would drop to 1.36 percent. In other words, the composite depreciation rate for Palo Verde in total would be cut by more than half, as a result of reflecting the impact of the license extension.

Q. How is the implementation of new depreciation rates by a utility typically coordinated with the ratemaking process?

A. Typically, the implementation of new depreciation rates is coordinated with the ratemaking process by having new depreciation rates be implemented at the same time that a utility's new base rates become effective.

Q. Why is that coordination of new depreciation rates in the ratemaking process usually considered important?

A. Depreciation expense is a significant component of a utility's cost of service. Coordinating the implementation of new depreciation rates, especially where the new rates represent significant changes from the existing rates, with changes in the utility's base

[7] As shown in the Settlement Agreement, Attachment B, APS does not apply depreciation rates for its generating units on a composite basis; rather, APS applies such depreciation rates by unit and by type of plant.

rates for utility service helps assure that the Depreciation Expense and Accumulated Depreciation that the utility records on its books is coordinated with the rates that ratepayers are paying for utility service. Accumulated Depreciation is a significant offset to a utility's rate base.

Q. How does the Settlement Agreement provide for the implementation by APS of new, significantly lower depreciation rates related to a Palo Verde life extension?

A. Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012.

Q. How is this provision intended to benefit APS?

A. As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. APS' reported earnings would be improved by recording lower depreciation expense for some period before the lower depreciation expense is recognized in the establishment of customer rates for electric service.

Q. How could this provision in the Settlement result in higher future costs to APS' ratepayers?

A. It could result in a higher rate base from a lower amount of Accumulated Depreciation compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect. Specifically, APS would be recording

lower Palo Verde Depreciation Expense before lower recorded depreciation expense amounts are recognized in the ratemaking process. During that period, the amount of Accumulated Depreciation (a rate base offset) recorded by APS would be lower and, consequently, APS' rate base in a future rate case (or cases) would be higher than compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect.

Q. When would APS ratepayers start to benefit from the lower Palo Verde depreciation expense?

A. Ratepayers would start to benefit from the lower Palo Verde depreciation expenses once APS' base rates were adjusted in a future rate case to reflect the impact of this reduced expense.

Q. Would a Palo Verde life extension affect any other expenses?

A. Yes. Other things being equal, a Palo Verde life extension would also be expected to significantly reduce APS' nuclear decommissioning expense.

Q. How does the Settlement Agreement provide for recognizing the impact of decreased decommissioning expense?

A. The Settlement Agreement at paragraph 11.1 provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension. Moreover, it is the Signatories' intention that the reduction in decommissioning expense be passed onto APS' ratepayers, via a reduction to the SBC, concurrently with when APS begins to record the lower Palo Verde depreciation expense on its books.

Q. Does this conclude your Testimony?

A. Yes, it does.

Arizona Public Service Company
Base Fuel and Purchased Power

Test Year Ended December 31, 2007

Attachment RCS-8
Docket No. E-01345A-08-0172
Schedule C-15
Page 1 of 1

UPDATED FOR SETTLEMENT

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)	Reference
1	Adjustment to Base Fuel and Purchased Power	$ (32,317,378)	$ (32,317,378)	A
1a	**PER SETTLEMENT**	**$ (35,425,907)**	**$ (35,425,907)**	
1b	Difference	$ (3,108,529)	$ (3,108,529)	

Notes and Source

A: Per APS Witness Ewen Attachment PME-3 and APS' supplemental response to Staff ___

	Adjusted Test Year Fuel and Purchased Power Costs (cents per kWh)	Per APS	Per Staff	Adjustment
2	Normalized Fuel and Purchased Costs	3.8783	3.7677	
3	Test Year Fuel and Purchased Power Costs	3.4346	3.4346	
4	Difference	0.4437	0.3331	
	Adjusted Test Year Retail Sales (MWh)			
5	Test Year Retail Sales (MWh)	29,171,321,000	29,171,321,000	
6	Pro Forma Adjustment to Normalize Weather	(445,396,000)	(445,396,000)	
7	Pro Forma Adjustment to Annualize 12/31/07 Customer Level	494,127,000	494,127,000	
8	Adjusted Test Year Retail Sales	29,220,052,000	29,220,052,000	
9	Pro Forma Adjustment to Fuel and Purchased Power Expense	$ 129,649,371	$ 97,331,993	$ (32,317,378)

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			Per Staff Direct Filing		
10	Normalized Fuel and Purchased Costs	3.8783	3.7677		
11	Existing base fuel rate	3.2491	3.2491		
12	Increase above current base cost of fuel	0.6292	0.5186		($000)
13	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 151,535,190	$ (32,328,581)	$(32,329)
14	Related reduction in PSA revenue	$ 169,987,454	$ 140,098,732	$ (29,888,722)	$(29,889)
15	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,436,458	$ (2,439,859)	$ (2,440)
16	Rounded to thousands	$ 13,876	$ 11,436	$ (2,440)	

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			PER SETTLEMENT		
17	Related reduction in PSA revenue	169,987,454.0000	3.7571	**Per APS's PSA filing**	
18	Existing base fuel rate	3.2491	3.2491		
19	Increase above current base cost of fuel	169,987,450.7509	0.5080		($000)
20	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 148,437,864	$ (35,425,907)	$(35,426)
21	Related reduction in PSA revenue	$ 169,987,454	$ 137,235,163	$ (32,752,291)	$(32,752)
22	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,202,701	$ (2,673,616)	$ (2,674)
23	Rounded to thousands	$ 13,876	$ 11,203	$ (2,673)	
24	Difference from Staff direct filing		$ (233)	$ (233)	

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

TESTIMONY SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JULY 01, 2009

TABLE OF CONTENTS

		Page
INTRODUCTION		1
DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS		2
III.	Rate Increase	2
IV.	Cost of Capital and Fair Value Rate of Return	9
V.	Depreciation	10
VI.	Fuel and Power Supply Adjustment Provisions	11
VIII.	Equity Infusions into APS	12
IX.	Pension and OPEB Deferrals	13
X.	Treatment of Schedule 3	14
XI.	Adjustment to Depreciation Rates for Palo Verde License Extension	15

ATTACHMENTS

Calculation of Base Cost of Fuel and Purchased Power RCS-8

EXECUTIVE SUMMARY
TESTIMONY IN SUPPORT OF SETTLEMENT OF RALPH C. SMITH
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My testimony in support of the Settlement addresses the following sections of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

A summary of my testimony concerning the Settlement Agreement for each of these areas follows:

III. Rate Increase.

For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue is approximately $196.3 million, plus $11.2 million for a fuel related increase in base rates, plus $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion.

Settlement paragraph 3.8 shows how the base rate increase provided for in the Settlement compares with various Signatories' initial proposed increases. It has columns for APS's original filing, Staff's direct filing, Residential Utility Consumer Office's ("RUCO") direct filing, Arizonan for Electric Choice and Competition's ("AECC") direct filing, and the Settlement. The $344.7 million total rate increase is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

In addition to the amount of base rate increase, the Settlement Agreement also provides for exceptional accounting treatments for APS for Pension and Other Post and Employee Benefit ("OPEB") deferrals (in Section IX), for treating Schedule 3 receipts as revenue (in Section X) and for an adjustment to Palo Verde depreciation rates for a License Extension (in Section XI). Each of these special accounting provisions has future rate consequences for APS ratepayers.

IV. Cost of Capital and Fair Value Rate of Return

The Settlement Agreement at paragraphs 4.1 through 4.3 provides for an overall cost of capital of 8.58 percent and a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A. It provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Additionally, as explained on page 8 of Staff witness Johnson's direct testimony, as a matter of policy Staff proposed a fair value rate of return ("FVROR") that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB"). This 1.5 percent return was incorporated into the FVROR for Settlement Purposes, as shown on line 9 of Settlement Attachment A. As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with an additional base rate increase of $51.265 million.

V. Depreciation

Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent.

VI. Fuel and Power Supply Adjustment Provisions

Section VI of the Settlement Agreement addresses the provisions of the Purchased Power Fuel Adjustor Clause that has been agreed to by the parties through the process of negotiation. As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued. The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates. Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism. The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

VIII. Equity Infusions into APS

As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014. This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009. Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. Pension and OPEB Deferrals

Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs in 2011 and 2012 if such costs exceed the test year level, which the parties to the Settlement Agreement have identified as $23.949 million. Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

X. Treatment of Schedule 3

Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. Currently, APS records Schedule 3 receipts as Contributions in Aid to Construction ("CIAC"). As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

XI. Adjustment to Depreciation Rates for Palo Verde License Extension

Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Paragraph 11.1 also provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension.

As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. During that period, the lower recorded depreciation expense amounts mean that Accumulated Depreciation (a rate base offset) would be lower and APS' rate base in the next rate case would be higher.

As with the other aspects of the Settlement Agreement that involved compromises from Staff's normal litigation position on such issues, Staff witness Ernest Johnson is addressing the policy reasons for this treatment in the context of the Settlement Agreement.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding?

A. Yes.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-8 presents an update of Staff Schedule C-15 showing additional details for the adjustment to fuel and purchased power expense.

Q. What is the purpose of your testimony in support of the settlement?

A. The purpose of my testimony in support of the settlement is to explain the derivation of the base rate increase, some of the figures, and some of the other accounting treatments that are provided for in the Settlement. The base rate increase provided for in the Settlement is strictly for purposes of this Settlement and should not be viewed as necessarily representing positions that Staff would be advocating in any other situation. All of the Staff policy decisions related to the Settlement are addressed in the testimony of Staff witness Ernest Johnson.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your testimony?

A. My testimony addresses aspects of the following provisions of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

The numbering of these provisions in my testimony corresponds with the Settlement Agreement.

III. RATE INCREASE

Q. For Settlement purposes, to what amount of base rate increase did the signing parties agree?

A. For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue of $344.7 million is the sum of three components: (1) a non-fuel related base rate increase of approximately $196.3 million; (2) approximately $11.2 million for a fuel related increase in base rates; and (3)

approximately $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

Q. What fair value rate base and fair value rate of return did the signing parties agree to for Settlement purposes?

A. As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A.

Q. How does the amount of revenue increase provided for in the Settlement Agreement compare with what APS, Staff and other signatories had originally proposed?

A. A table shown on Settlement page 13, paragraph 3.8 (which is reproduced below for ease of reference) summarizes the base rate and total rate increase that APS, Staff, Residential Utility Consumer Office ("RUCO") and Arizonan for Electric Choice and Competition ("AECC") each had originally recommended, and shows the corresponding Settlement amounts:

Comparison of APS, Staff, RUCO and Settlement Summary of Base Rate Increase (Thousands of Dollars)	APS Proposed	Staff Proposed	RUCO Proposed	AECC Proposed	Settlement
Components of Total Rate Increase					
Base Rate Increase	$ 264,341	$ 155,062	$ (27,281)	$ 205,444	$ 196,300
Fuel Related Increase in Base Rates	$ 13,876	$ 11,436	$ 13,876	$ 10,695	$ 11,203
Total Base Rate Increase	$ 278,217	$ 166,498	$ (13,405)	$ 216,139	$ 207,503
Adjusted Base Cost of Fuel Related Increase	$ 169,977	$ 140,088	$ 169,977	$ 130,527	$ 137,235
Total Rate Increase Requested	$ 448,194	$ 306,586	$ 156,572	$ 346,666	$ 344,738
Percentage Increase Over Current Rates					
Revenue from Sales to Ultimate Retail Customers					
2007 Test Year Adjusted	$ 2,637,447	$ 2,637,447	$ 2,748,697	$ 2,637,447	$ 2,637,447
Percentage Increase - Net of PSA	10.55%	6.31%	-0.49%	8.20%	7.87%
Percentage Increase - Total	16.99%	11.62%	5.70%	13.14%	13.07%
Revenue from Sales to Ultimate Retail Customers					
2010 Base Rate Revenue per APS	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236
Percentage Increase - Net of PSA	10.48%	6.27%	-0.51%	8.14%	7.82%
Percentage Increase - Total	16.89%	11.55%	5.90%	13.06%	12.99%

The $344.7 million total rate increase provided for in the Settlement is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

Q. Has a portion of the amount of base rate increase provided for in the Settlement already been implemented by APS?

A. Yes. A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

Q. Referring to the above table, please explain briefly how the Settlement "base rate increase" amount of $196.3 million was derived.

A. The "base rate increase" of $196.3 million was arrived at through lengthy negotiations between the Signatories over the past 5-6 months. Staff witness Ernest Johnson's testimony in support of the Settlement explains the policy considerations involved. In dollar terms, the following presents a rough synopsis of the $196.3 million base rate

revenue increase provided for in the Settlement, starting from the recommendation in Staff's direct testimony filing:

Approximate Derivation of the $196.3 Million
(Amounts in Millions)

Line No.	Description	Revenue Requirement Amount (Decrease) Increase	Reference
1	Staff base rate revenue increase	$ 155.1	Attachment RCS-2, Sch A, p.2, Col.B, L.9
	Supplemental:		
2	Remove APS adjustment for DSM Lost Revenue aka Uncollected Fixed Costs	$ (15.7)	R Smith Supplemental Direct filed 1-9-2009
	Corrections:		
3	Yucca Units 5 & 6	$ 1.0	Settlement Negotiations
4	Income Tax Calculation/Interest Synchronization	$ 7.4	Settlement Negotiations
	Additions:		
5	Additional Post Test Year Plant	$ 48.6	Settlement Negotiations
6	**Base rate revenue increase per Settlement**	**$ 196.3**	Settlement Negotiations (sum of Lines 1-5)*

*Numbers may not add exactly due to rounding.

Q. Please briefly explain the adjustment to remove the APS adjustment for DSM Lost Revenue also know as Uncollected Fixed Costs.

A. This adjustment was addressed in my supplemental testimony, filed on January 9, 2009. APS witness Ewen's Attachment PME-13 (filed with his direct testimony) and described in his direct testimony at page 33, shows that APS had proposed to reduce test year operating revenue by $16.789 million for 220,696 MWh of lost sales, and to reduce related operating expenses by $1.052 million, for a net reduction to pre-tax operating income of $15.738 million. In Docket No. E-01345A-05-0816 et al, APS had proposed a pro forma adjustment for estimated 2006 lost revenues from DSM programs in conjunction with a test year ended September 30, 2005, i.e., approximately 1.25 years beyond the test year. In the current case, APS has proposed a pro forma adjustment for estimated 2010 lost revenue from DSM programs in conjunction with a 2007 test year,

i.e., three years beyond the test year. In Decision No. 69663, the Commission had rejected the similar adjustment proposed by APS in that rate case. As I had stated in my supplemental testimony (at page 3):

> The approximate impact from APS' proposed adjustment no. 13 to the revenue requirement is $15.7 million. ... Unless APS provides a compelling argument for this adjustment, including a strong argument why a conclusion different than Decision No. 69663 is required, Staff will reverse APS proposed adjustment no. 13 when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing.

The Settlement Agreement revenue requirement reflects this reduction of $15.7 million to reverse APS' proposed adjustment for DSM lost revenues also known as Unrecovered Fixed Charges.

Q. Please briefly explain the correction items to Staff's direct-filed revenue requirement.

A. It was brought to my attention that there were two errors in the calculation of Staff's revenue requirement. The first item related to including in jurisdictional rate base the cost of a step-up transformer for Yucca Units 5 and 6 and reflected actual costs incurred for plant balances through 12/31/08 as opposed to 09/30/08 actual costs incurred. The second item related to a correction to Staff's interest synchronization calculation for the amount "per APS' filing"[1] to take into account the interest synchronization that was reflected by the Company in each individual pro forma adjustments on APS Schedule C-2. These two corrections to Staff's revenue requirement were accepted by Staff and the other Signatories in Settlement discussions, and were reflected in deriving the amount of base rate increase that is provided for in the Settlement.

[1] See, Attachment RCS-2, Schedule C-13, line 4, as filed with my direct testimony.

Q. Please briefly explain the adjustment for additional post test year plant.

A. The additional $48.6 million represents one way of deriving an adjustment to the revenue requirement to provide rate recognition for additional APS post-test year plant additions through June 30, 2009, i.e., for a period of 18 months beyond the 2007 test year. Staff witness Ernest Johnson's testimony in support of the settlement explains the reasons for why Staff agreed to including this for purposes of deriving the amount of revenue increase provided for in the Settlement.

Q. The next item in the Settlement Agreement, paragraph 3.8, in the "Settlement" column, is $11.203 million for a "Fuel Related Increase in Base Rates." Can you please briefly explain that item?

A. Yes. This item is comparable to the $11.436 million shown in the "Staff Proposed" column.[2] When the Company's Base Cost of Fuel is reestablished in a base rate case, this impacts the amounts that APS can recover through its Power Supply Adjustor ("PSA") mechanism, which has a 90/10 sharing provision.[3] The reestablishment of a higher Base Cost of Fuel in this case allows APS to recover in base rates approximately $11.203 million more than APS would have been able to recover in increased fuel and purchased power costs solely through the operation of the PSA.

Staff's adjustment for the Base Cost of Fuel was presented on Attachment RCS-2, Schedule C-15, filed with my direct testimony. In that adjustment, Staff had used a base cost of fuel of 3.7677 cents per kWh. The Settlement Agreement (at paragraph 6.2) provides for a slightly lower Base Cost of Fuel of 3.7571 cents per kWh. This difference in the Base Cost of Fuel is attributed to the decrease of approximately $233,000 from the

[2] This amount also appears on Attachment RCS-2 (to my direct testimony), Schedule A, page 1, line 9, and page 2, line 10.
[3] Per Settlement Agreement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued for purposes of the resolution of this rate case.

$11.436 million in Staff's direct filing to the $11.203 million provided for in the Settlement.

Q. Have you prepared an update to Staff Schedule C-15 that shows this?

A. Yes. Attachment RCS-8 to my testimony in support of the Settlement updates Staff Schedule C-15, and includes some additional calculation detail, showing the derivation of the $11.203 million Settlement amount and the $11.436 million amount from Staff's direct filing.

Q. Please briefly explain the "Adjusted Base Cost of Fuel Related Increase" of $137.235 million that appears in the Settlement Agreement, paragraph 3.8 table.

A. The $137.235 million represents the amount of fuel and purchased power cost increase that is now to be included in APS' base rates, at the Base Cost of Fuel of 3.7571 cents per kWh. Were it not for the base rate case, APS would have recovered this amount of fuel and purchased power cost increase through the operation of its PSA. The derivation of the $137.235 million is also shown on Attachment RCS-8.

Q. What average percentage increase in base rates does the revenue increase of $344.738 million represent?

A. As shown in the Settlement Agreement at paragraph 3.8, this represents an average increase of approximately 13.07 percent over the adjusted 2007 test year base rate revenue.

Q. Are there other provisions in the Settlement Agreement that would result in future rate increases to APS customers?

A. Yes. As described in the Settlement at paragraph 3.9, APS has various adjustor mechanisms, which are estimated to produce net additional rate increases. Staff witness Barbara Keene's testimony in support of the settlement addresses those mechanisms. Additionally, as described in the Settlement at paragraph 3.10, there are other provisions of the Settlement which do not have a rate impact in the present case, but will have an impact in future APS rate cases. I address some of those items in subsequent sections of my testimony in support of the Settlement.

IV. COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. Please refer to paragraphs 4.1 and 4.2 of the Settlement Agreement. What is the source for the capital structure and cost rates?

A. The source for the capital structure and cost rates specified in paragraphs 4.1 and 4.2 of the Settlement Agreement is the agreement of the Signatories. These amounts can also be found in Staff's direct filing at Attachment RCS-2, Schedule D, lines 5-8, and produce a weighted cost of capital of 8.58 percent.

The Settlement Agreement provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Q. Please refer to paragraph 4.3 of the Settlement Agreement. How was the 6.65 percent calculated?

A. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR"), which is calculated as shown on Settlement Attachment A.

As explained on page 8 of Staff witness Johnson's direct testimony, as a policy decision in this case, Staff had proposed a revenue requirement for APS using a FVROR that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB").

As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with a base rate increase of $51.265 million that was in addition to the OCRB-based calculation. This 1.5 percent return was also incorporated into the FVROR for Settlement Purposes, as shown on line 9, of Settlement Attachment A.

V. DEPRECIATION

Q. Please address the depreciation rates provided for in the Settlement Agreement at Section V.

A. Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent. This treatment is consistent with the recommendations made concerning depreciation rates in the Staff direct filing.

VI. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

Q. Please address the Fuel and Power Supply Adjustment provisions provided for in the Settlement Agreement at Section VI.

A. Section VI of the Settlement Agreement addresses the provisions of the PSA that have been agreed to by the Signatories through the process of negotiation.

As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued.

The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates.

Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism.

The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

Q. How does the Base Cost of Fuel and Purchased Power of 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 compare with APS' and Staff's direct filings?

A. The 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 corresponds to the forward-looking PSA rate currently in effect for APS. It is lower than both the 3.8783 cents per kWh used by APS in its direct filing and the 3.7677 cents per kWh from Staff's direct filing. It thus reflects, at least in part, the lower cost of fuel that APS has been experiencing recently.

Paragraph 2.6 of the Settlement Agreement provides for the possibility of an accelerated PSA reset at the time new base rates are implemented if APS's fuel and purchased power costs result in a PSA over-collected balance at that time.

Q. Please explain the Settlement treatment of the Gain on Sale of SO_2 Allowances.

A. The Settlement Agreement at paragraph 6.3 provides that Gains on SO_2 Allowance sales over or under the normalized jurisdictional test year amount shall be recovered and/or refunded through the PSA mechanism.

Staff's derivation of the proposed revenue increase had reflected a normalized amount of Gains on the Sale of SO_2 Allowances of approximately $7.045 million as an offset to the test year expenses[4] (which in turn reduced the amount of the base rate revenue increase). Staff's recommendation was also that annual fluctuations above or below the amounts reflected in base rates for Gains on the Sale of SO_2 Allowances should be reflected as adjustments to PSA-includable costs. The Settlement provides for 100 percent of the annual Gains on the Sale of SO_2 Allowances to be credited in the PSA against PSA includable costs. Crediting such gains through the PSA is appropriate and reasonable because Gains on the Sale of SO_2 Emission Allowances are closely related to the amount of coal burned at APS's generating plants, can be significant in amount, and can fluctuate significantly from year to year.

VIII. EQUITY INFUSIONS INTO APS

Q. Please discuss the Settlement provisions for equity infusions into APS.

A. As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014.

[4] See Attachment RCS-2, Schedule C-14, Column B, line 1, as filed with my direct testimony.

This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009.

Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. PENSION AND OPEB DEFERRALS

Q. Please discuss the Settlement provisions for Pension and Other Post Employment Benefit ("OPEB") deferrals.

A. Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs by APS in 2011 and 2012 if such costs exceed the test year level, which the Signatories to the Settlement Agreement have identified as $23.949 million.

Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. The total additional cost to ratepayers from this provision could be as much as $42.5 million (if the maximum deferrals in 2011 of $13.5 million and 2012 of $29 million occur).

The annual impact to APS ratepayers would depend upon the amortization period selected in a future APS next rate case. For illustrative purposes, if a five-year amortization period were to be used, and the deferrals reached the maximum amount of $42.5 million, the annual impact on APS ratepayers would be approximately $8.5 million of additional rate increase per year.[5] If a seven-year amortization period were to be used, the annual impact

[5] $42.5 million / 5 years

on APS ratepayers would be approximately $6.1 million of additional rate increase per year.[6]

Another witness for Staff, Ernest Johnson, is addressing the policy reasons for why Staff has agreed to provide APS with the deferred accounting treatment.

X. TREATMENT OF SCHEDULE 3

Q. How does APS currently account for Schedule 3 receipts?

A. Currently, APS records Schedule 3 receipts as Contributions in Aid of Construction ("CIAC").

Q. How is CIAC typically treated for ratemaking purposes?

A. CIAC is typically treated for ratemaking purposes as an offset to rate base. The rate base offset amount related to CIAC is typically based on the unamortized CIAC balance, less an income tax impact that is accounted for in the balance of Accumulated Deferred Income Taxes ("ADIT").

As a simplified example, if a utility had $100 million of unamortized CIAC (and there was a 40 percent combined state and federal income tax rate), rate base would be reduced by approximately $60 million ($100 million of CIAC less $40 million of ADIT).

The amortization of CIAC is typically reflected for ratemaking purposes as an offset to a utility's depreciation expense.

[6] $42.5 million / 7 years

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Does accounting for Schedule 3 receipts as revenue during this period have future rate consequences?

A. Yes. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment.

Q. Is it possible to estimate the increased rate base, post-2012, that would result from APS' accounting for Schedule 3 receipts as revenue during the period, 2010 through 2012?

A. Not reliably. The amounts identified by APS for 2010-2012 sum to $97 million. The rate base increase would be approximately the sum of the Schedule 3 amounts for 2010-2012 that APS accounted for as revenue, rather than as CIAC, less the related ADIT impact.

XI. ADJUSTMENT TO DEPRECIATION RATES FOR PALO VERDE LICENSE EXTENSION

Q. Has APS applied for a Palo Verde license extension?

A. Yes. APS has applied for a license extension for the Palo Verde nuclear generating plant.

Q. How would APS' depreciation rates be impacted by a Palo Verde license extension?

A. The cost of the plant is being depreciated over the remaining period of the license. With a license extension, the remaining cost of the plant would be depreciated over a significantly longer period, and the result would be significantly lower depreciation rates.

Q. Where are the anticipated new depreciation rates related to a Palo Verde life extension specified in the Settlement Agreement?

A. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Q. Are the new depreciation rates related to a Palo Verde life extension significantly lower than the present Palo Verde depreciation rates?

A. Yes. Referring to Settlement Agreement Attachment B, for example, at page 5 of 8, APS' current depreciation rate for Palo Verde, on a composite basis, is 2.80 percent. With a license extension, the Palo Verde composite depreciation rate[7] would drop to 1.36 percent. In other words, the composite depreciation rate for Palo Verde in total would be cut by more than half, as a result of reflecting the impact of the license extension.

Q. How is the implementation of new depreciation rates by a utility typically coordinated with the ratemaking process?

A. Typically, the implementation of new depreciation rates is coordinated with the ratemaking process by having new depreciation rates be implemented at the same time that a utility's new base rates become effective.

Q. Why is that coordination of new depreciation rates in the ratemaking process usually considered important?

A. Depreciation expense is a significant component of a utility's cost of service. Coordinating the implementation of new depreciation rates, especially where the new rates represent significant changes from the existing rates, with changes in the utility's base

[7] As shown in the Settlement Agreement, Attachment B, APS does not apply depreciation rates for its generating units on a composite basis; rather, APS applies such depreciation rates by unit and by type of plant.

rates for utility service helps assure that the Depreciation Expense and Accumulated Depreciation that the utility records on its books is coordinated with the rates that ratepayers are paying for utility service. Accumulated Depreciation is a significant offset to a utility's rate base.

Q. How does the Settlement Agreement provide for the implementation by APS of new, significantly lower depreciation rates related to a Palo Verde life extension?

A. Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012.

Q. How is this provision intended to benefit APS?

A. As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. APS' reported earnings would be improved by recording lower depreciation expense for some period before the lower depreciation expense is recognized in the establishment of customer rates for electric service.

Q. How could this provision in the Settlement result in higher future costs to APS' ratepayers?

A. It could result in a higher rate base from a lower amount of Accumulated Depreciation compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect. Specifically, APS would be recording

lower Palo Verde Depreciation Expense before lower recorded depreciation expense amounts are recognized in the ratemaking process. During that period, the amount of Accumulated Depreciation (a rate base offset) recorded by APS would be lower and, consequently, APS' rate base in a future rate case (or cases) would be higher than compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect.

Q. When would APS ratepayers start to benefit from the lower Palo Verde depreciation expense?

A. Ratepayers would start to benefit from the lower Palo Verde depreciation expenses once APS' base rates were adjusted in a future rate case to reflect the impact of this reduced expense.

Q. Would a Palo Verde life extension affect any other expenses?

A. Yes. Other things being equal, a Palo Verde life extension would also be expected to significantly reduce APS' nuclear decommissioning expense.

Q. How does the Settlement Agreement provide for recognizing the impact of decreased decommissioning expense?

A. The Settlement Agreement at paragraph 11.1 provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension. Moreover, it is the Signatories' intention that the reduction in decommissioning expense be passed onto APS' ratepayers, via a reduction to the SBC, concurrently with when APS begins to record the lower Palo Verde depreciation expense on its books.

1 **Q. Does this conclude your Testimony?**

2 A. Yes, it does.

Arizona Public Service Company
Base Fuel and Purchased Power

Test Year Ended December 31, 2007

Attachment RCS-8
Docket No. E-01345A-08-0172
Schedule C-15
Page 1 of 1

UPDATED FOR SETTLEMENT

Line No.	Description	Total Company Amount (A)	ACC *Jurisdictional* Amount (B)	Reference
1	Adjustment to Base Fuel and Purchased Power	$ (32,317,378)	$ (32,317,378)	A
1a	**PER SETTLEMENT**	**$ (35,425,907)**	**$ (35,425,907)**	
1b	Difference	$ (3,108,529)	$ (3,108,529)	

Notes and Source

A: Per APS Witness Ewen Attachment PME-3 and APS' supplemental response to Staff ___

	Adjusted Test Year Fuel and Purchased Power Costs (cents per kWh)	Per APS	Per Staff	Adjustment
2	Normalized Fuel and Purchased Costs	3.8783	3.7677	
3	Test Year Fuel and Purchased Power Costs	3.4346	3.4346	
4	Difference	0.4437	0.3331	
	Adjusted Test Year Retail Sales (MWh)			
5	Test Year Retail Sales (MWh)	29,171,321,000	29,171,321,000	
6	Pro Forma Adjustment to Normalize Weather	(445,396,000)	(445,396,000)	
7	Pro Forma Adjustment to Annualize 12/31/07 Customer Level	494,127,000	494,127,000	
8	Adjusted Test Year Retail Sales	29,220,052,000	29,220,052,000	
9	Pro Forma Adjustment to Fuel and Purchased Power Expense	$ 129,649,371	$ 97,331,993	$ (32,317,378)

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			Per Staff Direct Filing		
10	Normalized Fuel and Purchased Costs	3.8783	**3.7677**		
11	Existing base fuel rate	3.2491	3.2491		
12	Increase above current base cost of fuel	0.6292	0.5186		($000)
13	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 151,535,190	$ (32,328,581)	$(32,329)
14	Related reduction in PSA revenue	$ 169,987,454	$ 140,098,732	$ (29,888,722)	$(29,889)
15	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,436,458	$ (2,439,859)	$ (2,440)
16	Rounded to thousands	$ 13,876	$ 11,436	$ (2,440)	

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			PER SETTLEMENT		
17	Related reduction in PSA revenue	169,987,454.0000	**3.7571**	**Per APS's PSA filing**	
18	Existing base fuel rate	3.2491	3.2491		
19	Increase above current base cost of fuel	169,987,450.7509	0.5080		($000)
20	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 148,437,864	$ (35,425,907)	$(35,426)
21	Related reduction in PSA revenue	$ 169,987,454	$ 137,235,163	$ (32,752,291)	$(32,752)
22	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,202,701	$ (2,673,616)	$ (2,674)
23	Rounded to thousands	$ 13,876	$ 11,203	$ (2,673)	
24	Difference from Staff direct filing		$ (233)	$ (233)	

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

TESTIMONY SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JULY 01, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 2

III. Rate Increase 2

IV. Cost of Capital and Fair Value Rate of Return 9

V. Depreciation 10

VI. Fuel and Power Supply Adjustment Provisions 11

VIII. Equity Infusions into APS 12

IX. Pension and OPEB Deferrals 13

X. Treatment of Schedule 3 14

XI. Adjustment to Depreciation Rates for Palo Verde License Extension 15

ATTACHMENTS

Calculation of Base Cost of Fuel and Purchased Power RCS-8

EXECUTIVE SUMMARY
TESTIMONY IN SUPPORT OF SETTLEMENT OF RALPH C. SMITH
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My testimony in support of the Settlement addresses the following sections of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

A summary of my testimony concerning the Settlement Agreement for each of these areas follows:

III. Rate Increase.

For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue is approximately $196.3 million, plus $11.2 million for a fuel related increase in base rates, plus $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion.

Settlement paragraph 3.8 shows how the base rate increase provided for in the Settlement compares with various Signatories' initial proposed increases. It has columns for APS's original filing, Staff's direct filing, Residential Utility Consumer Office's ("RUCO") direct filing, Arizonan for Electric Choice and Competition's ("AECC") direct filing, and the Settlement. The $344.7 million total rate increase is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

In addition to the amount of base rate increase, the Settlement Agreement also provides for exceptional accounting treatments for APS for Pension and Other Post and Employee Benefit ("OPEB") deferrals (in Section IX), for treating Schedule 3 receipts as revenue (in Section X) and for an adjustment to Palo Verde depreciation rates for a License Extension (in Section XI). Each of these special accounting provisions has future rate consequences for APS ratepayers.

IV. Cost of Capital and Fair Value Rate of Return

The Settlement Agreement at paragraphs 4.1 through 4.3 provides for an overall cost of capital of 8.58 percent and a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A. It provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Additionally, as explained on page 8 of Staff witness Johnson's direct testimony, as a matter of policy Staff proposed a fair value rate of return ("FVROR") that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB"). This 1.5 percent return was incorporated into the FVROR for Settlement Purposes, as shown on line 9 of Settlement Attachment A. As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with an additional base rate increase of $51.265 million.

V. Depreciation

Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent.

VI. Fuel and Power Supply Adjustment Provisions

Section VI of the Settlement Agreement addresses the provisions of the Purchased Power Fuel Adjustor Clause that has been agreed to by the parties through the process of negotiation. As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued. The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates. Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism. The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

VIII. Equity Infusions into APS

As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014. This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009. Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. Pension and OPEB Deferrals

Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs in 2011 and 2012 if such costs exceed the test year level, which the parties to the Settlement Agreement have identified as $23.949 million. Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

X. Treatment of Schedule 3

Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. Currently, APS records Schedule 3 receipts as Contributions in Aid to Construction ("CIAC"). As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

XI. Adjustment to Depreciation Rates for Palo Verde License Extension

Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Paragraph 11.1 also provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension.

As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. During that period, the lower recorded depreciation expense amounts mean that Accumulated Depreciation (a rate base offset) would be lower and APS' rate base in the next rate case would be higher.

As with the other aspects of the Settlement Agreement that involved compromises from Staff's normal litigation position on such issues, Staff witness Ernest Johnson is addressing the policy reasons for this treatment in the context of the Settlement Agreement.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding?

A. Yes.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-8 presents an update of Staff Schedule C-15 showing additional details for the adjustment to fuel and purchased power expense.

Q. What is the purpose of your testimony in support of the settlement?

A. The purpose of my testimony in support of the settlement is to explain the derivation of the base rate increase, some of the figures, and some of the other accounting treatments that are provided for in the Settlement. The base rate increase provided for in the Settlement is strictly for purposes of this Settlement and should not be viewed as necessarily representing positions that Staff would be advocating in any other situation. All of the Staff policy decisions related to the Settlement are addressed in the testimony of Staff witness Ernest Johnson.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your testimony?

A. My testimony addresses aspects of the following provisions of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

The numbering of these provisions in my testimony corresponds with the Settlement Agreement.

III. RATE INCREASE

Q. For Settlement purposes, to what amount of base rate increase did the signing parties agree?

A. For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue of $344.7 million is the sum of three components: (1) a non-fuel related base rate increase of approximately $196.3 million; (2) approximately $11.2 million for a fuel related increase in base rates; and (3)

approximately $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

Q. What fair value rate base and fair value rate of return did the signing parties agree to for Settlement purposes?

A. As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A.

Q. How does the amount of revenue increase provided for in the Settlement Agreement compare with what APS, Staff and other signatories had originally proposed?

A. A table shown on Settlement page 13, paragraph 3.8 (which is reproduced below for ease of reference) summarizes the base rate and total rate increase that APS, Staff, Residential Utility Consumer Office ("RUCO") and Arizonan for Electric Choice and Competition ("AECC") each had originally recommended, and shows the corresponding Settlement amounts:

Comparison of APS, Staff, RUCO and Settlement Summary of Base Rate Increase (Thousands of Dollars)	APS Proposed	Staff Proposed	RUCO Proposed	AECC Proposed	Settlement
Components of Total Rate Increase					
Base Rate Increase	$ 264,341	$ 155,062	$ (27,281)	$ 205,444	$ 196,300
Fuel Related Increase in Base Rates	$ 13,876	$ 11,436	$ 13,876	$ 10,695	$ 11,203
Total Base Rate Increase	$ 278,217	$ 166,498	$ (13,405)	$ 216,139	$ 207,503
Adjusted Base Cost of Fuel Related Increase	$ 169,977	$ 140,088	$ 169,977	$ 130,527	$ 137,235
Total Rate Increase Requested	$ 448,194	$ 306,586	$ 156,572	$ 346,666	$ 344,738
Percentage Increase Over Current Rates					
Revenue from Sales to Ultimate Retail Customers 2007 Test Year Adjusted	$ 2,637,447	$ 2,637,447	$ 2,748,697	$ 2,637,447	$ 2,637,447
Percentage Increase - Net of PSA	10.55%	6.31%	-0.49%	8.20%	7.87%
Percentage Increase - Total	16.99%	11.62%	5.70%	13.14%	13.07%
Revenue from Sales to Ultimate Retail Customers 2010 Base Rate Revenue per APS	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236
Percentage Increase - Net of PSA	10.48%	6.27%	-0.51%	8.14%	7.82%
Percentage Increase - Total	16.89%	11.55%	5.90%	13.06%	12.99%

The $344.7 million total rate increase provided for in the Settlement is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

Q. Has a portion of the amount of base rate increase provided for in the Settlement already been implemented by APS?

A. Yes. A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

Q. Referring to the above table, please explain briefly how the Settlement "base rate increase" amount of $196.3 million was derived.

A. The "base rate increase" of $196.3 million was arrived at through lengthy negotiations between the Signatories over the past 5-6 months. Staff witness Ernest Johnson's testimony in support of the Settlement explains the policy considerations involved. In dollar terms, the following presents a rough synopsis of the $196.3 million base rate

revenue increase provided for in the Settlement, starting from the recommendation in Staff's direct testimony filing:

Approximate Derivation of the $196.3 Million
(Amounts in Millions)

Line No.	Description	Revenue Requirement Amount (Decrease) Increase	Reference
1	Staff base rate revenue increase	$ **155.1**	Attachment RCS-2, Sch A, p.2, Col.B, L.9
	Supplemental:		
2	Remove APS adjustment for DSM Lost Revenue aka Uncollected Fixed Costs	$ (15.7)	R Smith Supplemental Direct filed 1-9-2009
	Corrections:		
3	Yucca Units 5 & 6	$ 1.0	Settlement Negotiations
4	Income Tax Calculation/Interest Synchronization	$ 7.4	Settlement Negotiations
	Additions:		
5	Additional Post Test Year Plant	$ 48.6	Settlement Negotiations
6	**Base rate revenue increase per Settlement**	$ **196.3**	Settlement Negotiations (sum of Lines 1-5)*

*Numbers may not add exactly due to rounding.

Q. Please briefly explain the adjustment to remove the APS adjustment for DSM Lost Revenue also know as Uncollected Fixed Costs.

A. This adjustment was addressed in my supplemental testimony, filed on January 9, 2009. APS witness Ewen's Attachment PME-13 (filed with his direct testimony) and described in his direct testimony at page 33, shows that APS had proposed to reduce test year operating revenue by $16.789 million for 220,696 MWh of lost sales, and to reduce related operating expenses by $1.052 million, for a net reduction to pre-tax operating income of $15.738 million. In Docket No. E-01345A-05-0816 et al, APS had proposed a pro forma adjustment for estimated 2006 lost revenues from DSM programs in conjunction with a test year ended September 30, 2005, i.e., approximately 1.25 years beyond the test year. In the current case, APS has proposed a pro forma adjustment for estimated 2010 lost revenue from DSM programs in conjunction with a 2007 test year,

i.e., three years beyond the test year. In Decision No. 69663, the Commission had rejected the similar adjustment proposed by APS in that rate case. As I had stated in my supplemental testimony (at page 3):

> The approximate impact from APS' proposed adjustment no. 13 to the revenue requirement is $15.7 million. ... Unless APS provides a compelling argument for this adjustment, including a strong argument why a conclusion different than Decision No. 69663 is required, Staff will reverse APS proposed adjustment no. 13 when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing.

The Settlement Agreement revenue requirement reflects this reduction of $15.7 million to reverse APS' proposed adjustment for DSM lost revenues also known as Unrecovered Fixed Charges.

Q. Please briefly explain the correction items to Staff's direct-filed revenue requirement.

A. It was brought to my attention that there were two errors in the calculation of Staff's revenue requirement. The first item related to including in jurisdictional rate base the cost of a step-up transformer for Yucca Units 5 and 6 and reflected actual costs incurred for plant balances through 12/31/08 as opposed to 09/30/08 actual costs incurred. The second item related to a correction to Staff's interest synchronization calculation for the amount "per APS' filing"[1] to take into account the interest synchronization that was reflected by the Company in each individual pro forma adjustments on APS Schedule C-2. These two corrections to Staff's revenue requirement were accepted by Staff and the other Signatories in Settlement discussions, and were reflected in deriving the amount of base rate increase that is provided for in the Settlement.

[1] See, Attachment RCS-2, Schedule C-13, line 4, as filed with my direct testimony.

Q. Please briefly explain the adjustment for additional post test year plant.

A. The additional $48.6 million represents one way of deriving an adjustment to the revenue requirement to provide rate recognition for additional APS post-test year plant additions through June 30, 2009, i.e., for a period of 18 months beyond the 2007 test year. Staff witness Ernest Johnson's testimony in support of the settlement explains the reasons for why Staff agreed to including this for purposes of deriving the amount of revenue increase provided for in the Settlement.

Q. The next item in the Settlement Agreement, paragraph 3.8, in the "Settlement" column, is $11.203 million for a "Fuel Related Increase in Base Rates." Can you please briefly explain that item?

A. Yes. This item is comparable to the $11.436 million shown in the "Staff Proposed" column.[2] When the Company's Base Cost of Fuel is reestablished in a base rate case, this impacts the amounts that APS can recover through its Power Supply Adjustor ("PSA") mechanism, which has a 90/10 sharing provision.[3] The reestablishment of a higher Base Cost of Fuel in this case allows APS to recover in base rates approximately $11.203 million more than APS would have been able to recover in increased fuel and purchased power costs solely through the operation of the PSA.

Staff's adjustment for the Base Cost of Fuel was presented on Attachment RCS-2, Schedule C-15, filed with my direct testimony. In that adjustment, Staff had used a base cost of fuel of 3.7677 cents per kWh. The Settlement Agreement (at paragraph 6.2) provides for a slightly lower Base Cost of Fuel of 3.7571 cents per kWh. This difference in the Base Cost of Fuel is attributed to the decrease of approximately $233,000 from the

[2] This amount also appears on Attachment RCS-2 (to my direct testimony), Schedule A, page 1, line 9, and page 2, line 10.
[3] Per Settlement Agreement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued for purposes of the resolution of this rate case.

$11.436 million in Staff's direct filing to the $11.203 million provided for in the Settlement.

Q. Have you prepared an update to Staff Schedule C-15 that shows this?

A. Yes. Attachment RCS-8 to my testimony in support of the Settlement updates Staff Schedule C-15, and includes some additional calculation detail, showing the derivation of the $11.203 million Settlement amount and the $11.436 million amount from Staff's direct filing.

Q. Please briefly explain the "Adjusted Base Cost of Fuel Related Increase" of $137.235 million that appears in the Settlement Agreement, paragraph 3.8 table.

A. The $137.235 million represents the amount of fuel and purchased power cost increase that is now to be included in APS' base rates, at the Base Cost of Fuel of 3.7571 cents per kWh. Were it not for the base rate case, APS would have recovered this amount of fuel and purchased power cost increase through the operation of its PSA. The derivation of the $137.235 million is also shown on Attachment RCS-8.

Q. What average percentage increase in base rates does the revenue increase of $344.738 million represent?

A. As shown in the Settlement Agreement at paragraph 3.8, this represents an average increase of approximately 13.07 percent over the adjusted 2007 test year base rate revenue.

Q. Are there other provisions in the Settlement Agreement that would result in future rate increases to APS customers?

A. Yes. As described in the Settlement at paragraph 3.9, APS has various adjustor mechanisms, which are estimated to produce net additional rate increases. Staff witness Barbara Keene's testimony in support of the settlement addresses those mechanisms. Additionally, as described in the Settlement at paragraph 3.10, there are other provisions of the Settlement which do not have a rate impact in the present case, but will have an impact in future APS rate cases. I address some of those items in subsequent sections of my testimony in support of the Settlement.

IV. COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. Please refer to paragraphs 4.1 and 4.2 of the Settlement Agreement. What is the source for the capital structure and cost rates?

A. The source for the capital structure and cost rates specified in paragraphs 4.1 and 4.2 of the Settlement Agreement is the agreement of the Signatories. These amounts can also be found in Staff's direct filing at Attachment RCS-2, Schedule D, lines 5-8, and produce a weighted cost of capital of 8.58 percent.

The Settlement Agreement provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Q. Please refer to paragraph 4.3 of the Settlement Agreement. How was the 6.65 percent calculated?

A. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR"), which is calculated as shown on Settlement Attachment A.

As explained on page 8 of Staff witness Johnson's direct testimony, as a policy decision in this case, Staff had proposed a revenue requirement for APS using a FVROR that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB").

As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with a base rate increase of $51.265 million that was in addition to the OCRB-based calculation. This 1.5 percent return was also incorporated into the FVROR for Settlement Purposes, as shown on line 9, of Settlement Attachment A.

V. DEPRECIATION

Q. Please address the depreciation rates provided for in the Settlement Agreement at Section V.

A. Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent. This treatment is consistent with the recommendations made concerning depreciation rates in the Staff direct filing.

VI. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

Q. Please address the Fuel and Power Supply Adjustment provisions provided for in the Settlement Agreement at Section VI.

A. Section VI of the Settlement Agreement addresses the provisions of the PSA that have been agreed to by the Signatories through the process of negotiation.

As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued.

The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates.

Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism.

The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

Q. How does the Base Cost of Fuel and Purchased Power of 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 compare with APS' and Staff's direct filings?

A. The 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 corresponds to the forward-looking PSA rate currently in effect for APS. It is lower than both the 3.8783 cents per kWh used by APS in its direct filing and the 3.7677 cents per kWh from Staff's direct filing. It thus reflects, at least in part, the lower cost of fuel that APS has been experiencing recently.

Paragraph 2.6 of the Settlement Agreement provides for the possibility of an accelerated PSA reset at the time new base rates are implemented if APS's fuel and purchased power costs result in a PSA over-collected balance at that time.

Q. Please explain the Settlement treatment of the Gain on Sale of SO_2 Allowances.

A. The Settlement Agreement at paragraph 6.3 provides that Gains on SO_2 Allowance sales over or under the normalized jurisdictional test year amount shall be recovered and/or refunded through the PSA mechanism.

Staff's derivation of the proposed revenue increase had reflected a normalized amount of Gains on the Sale of SO_2 Allowances of approximately $7.045 million as an offset to the test year expenses[4] (which in turn reduced the amount of the base rate revenue increase). Staff's recommendation was also that annual fluctuations above or below the amounts reflected in base rates for Gains on the Sale of SO_2 Allowances should be reflected as adjustments to PSA-includable costs. The Settlement provides for 100 percent of the annual Gains on the Sale of SO_2 Allowances to be credited in the PSA against PSA includable costs. Crediting such gains through the PSA is appropriate and reasonable because Gains on the Sale of SO_2 Emission Allowances are closely related to the amount of coal burned at APS's generating plants, can be significant in amount, and can fluctuate significantly from year to year.

VIII. EQUITY INFUSIONS INTO APS

Q. Please discuss the Settlement provisions for equity infusions into APS.

A. As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014.

[4] See Attachment RCS-2, Schedule C-14, Column B, line 1, as filed with my direct testimony.

This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009.

Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. PENSION AND OPEB DEFERRALS

Q. Please discuss the Settlement provisions for Pension and Other Post Employment Benefit ("OPEB") deferrals.

A. Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs by APS in 2011 and 2012 if such costs exceed the test year level, which the Signatories to the Settlement Agreement have identified as $23.949 million.

Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. The total additional cost to ratepayers from this provision could be as much as $42.5 million (if the maximum deferrals in 2011 of $13.5 million and 2012 of $29 million occur).

The annual impact to APS ratepayers would depend upon the amortization period selected in a future APS next rate case. For illustrative purposes, if a five-year amortization period were to be used, and the deferrals reached the maximum amount of $42.5 million, the annual impact on APS ratepayers would be approximately $8.5 million of additional rate increase per year.[5] If a seven-year amortization period were to be used, the annual impact

[5] $42.5 million / 5 years

on APS ratepayers would be approximately $6.1 million of additional rate increase per year.[6]

Another witness for Staff, Ernest Johnson, is addressing the policy reasons for why Staff has agreed to provide APS with the deferred accounting treatment.

X. TREATMENT OF SCHEDULE 3

Q. How does APS currently account for Schedule 3 receipts?

A. Currently, APS records Schedule 3 receipts as Contributions in Aid of Construction ("CIAC").

Q. How is CIAC typically treated for ratemaking purposes?

A. CIAC is typically treated for ratemaking purposes as an offset to rate base. The rate base offset amount related to CIAC is typically based on the unamortized CIAC balance, less an income tax impact that is accounted for in the balance of Accumulated Deferred Income Taxes ("ADIT").

As a simplified example, if a utility had $100 million of unamortized CIAC (and there was a 40 percent combined state and federal income tax rate), rate base would be reduced by approximately $60 million ($100 million of CIAC less $40 million of ADIT).

The amortization of CIAC is typically reflected for ratemaking purposes as an offset to a utility's depreciation expense.

[6] $42.5 million / 7 years

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Does accounting for Schedule 3 receipts as revenue during this period have future rate consequences?

A. Yes. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment.

Q. Is it possible to estimate the increased rate base, post-2012, that would result from APS' accounting for Schedule 3 receipts as revenue during the period, 2010 through 2012?

A. Not reliably. The amounts identified by APS for 2010-2012 sum to $97 million. The rate base increase would be approximately the sum of the Schedule 3 amounts for 2010-2012 that APS accounted for as revenue, rather than as CIAC, less the related ADIT impact.

XI. ADJUSTMENT TO DEPRECIATION RATES FOR PALO VERDE LICENSE EXTENSION

Q. Has APS applied for a Palo Verde license extension?

A. Yes. APS has applied for a license extension for the Palo Verde nuclear generating plant.

Q. How would APS' depreciation rates be impacted by a Palo Verde license extension?

A. The cost of the plant is being depreciated over the remaining period of the license. With a license extension, the remaining cost of the plant would be depreciated over a significantly longer period, and the result would be significantly lower depreciation rates.

Q. Where are the anticipated new depreciation rates related to a Palo Verde life extension specified in the Settlement Agreement?

A. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Q. Are the new depreciation rates related to a Palo Verde life extension significantly lower than the present Palo Verde depreciation rates?

A. Yes. Referring to Settlement Agreement Attachment B, for example, at page 5 of 8, APS' current depreciation rate for Palo Verde, on a composite basis, is 2.80 percent. With a license extension, the Palo Verde composite depreciation rate[7] would drop to 1.36 percent. In other words, the composite depreciation rate for Palo Verde in total would be cut by more than half, as a result of reflecting the impact of the license extension.

Q. How is the implementation of new depreciation rates by a utility typically coordinated with the ratemaking process?

A. Typically, the implementation of new depreciation rates is coordinated with the ratemaking process by having new depreciation rates be implemented at the same time that a utility's new base rates become effective.

Q. Why is that coordination of new depreciation rates in the ratemaking process usually considered important?

A. Depreciation expense is a significant component of a utility's cost of service. Coordinating the implementation of new depreciation rates, especially where the new rates represent significant changes from the existing rates, with changes in the utility's base

[7] As shown in the Settlement Agreement, Attachment B, APS does not apply depreciation rates for its generating units on a composite basis; rather, APS applies such depreciation rates by unit and by type of plant.

rates for utility service helps assure that the Depreciation Expense and Accumulated Depreciation that the utility records on its books is coordinated with the rates that ratepayers are paying for utility service. Accumulated Depreciation is a significant offset to a utility's rate base.

Q. How does the Settlement Agreement provide for the implementation by APS of new, significantly lower depreciation rates related to a Palo Verde life extension?

A. Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012.

Q. How is this provision intended to benefit APS?

A. As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. APS' reported earnings would be improved by recording lower depreciation expense for some period before the lower depreciation expense is recognized in the establishment of customer rates for electric service.

Q. How could this provision in the Settlement result in higher future costs to APS' ratepayers?

A. It could result in a higher rate base from a lower amount of Accumulated Depreciation compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect. Specifically, APS would be recording

lower Palo Verde Depreciation Expense before lower recorded depreciation expense amounts are recognized in the ratemaking process. During that period, the amount of Accumulated Depreciation (a rate base offset) recorded by APS would be lower and, consequently, APS' rate base in a future rate case (or cases) would be higher than compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect.

Q. When would APS ratepayers start to benefit from the lower Palo Verde depreciation expense?

A. Ratepayers would start to benefit from the lower Palo Verde depreciation expenses once APS' base rates were adjusted in a future rate case to reflect the impact of this reduced expense.

Q. Would a Palo Verde life extension affect any other expenses?

A. Yes. Other things being equal, a Palo Verde life extension would also be expected to significantly reduce APS' nuclear decommissioning expense.

Q. How does the Settlement Agreement provide for recognizing the impact of decreased decommissioning expense?

A. The Settlement Agreement at paragraph 11.1 provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension. Moreover, it is the Signatories' intention that the reduction in decommissioning expense be passed onto APS' ratepayers, via a reduction to the SBC, concurrently with when APS begins to record the lower Palo Verde depreciation expense on its books.

Q. Does this conclude your Testimony?

A. Yes, it does.

Arizona Public Service Company
Base Fuel and Purchased Power

Test Year Ended December 31, 2007

Attachment RCS-8
Docket No. E-01345A-08-0172
Schedule C-15
Page 1 of 1

UPDATED FOR SETTLEMENT

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)	Reference
1	Adjustment to Base Fuel and Purchased Power	$ (32,317,378)	$ (32,317,378)	A
1a	**PER SETTLEMENT**	**$ (35,425,907)**	**$ (35,425,907)**	
1b	Difference	$ (3,108,529)	$ (3,108,529)	

Notes and Source

A: Per APS Witness Ewen Attachment PME-3 and APS' supplemental response to Staff ___

	Adjusted Test Year Fuel and Purchased Power Costs (cents per kWh)	Per APS	Per Staff	Adjustment
2	Normalized Fuel and Purchased Costs	3.8783	3.7677	
3	Test Year Fuel and Purchased Power Costs	3.4346	3.4346	
4	Difference	0.4437	0.3331	
	Adjusted Test Year Retail Sales (MWh)			
5	Test Year Retail Sales (MWh)	29,171,321,000	29,171,321,000	
6	Pro Forma Adjustment to Normalize Weather	(445,396,000)	(445,396,000)	
7	Pro Forma Adjustment to Annualize 12/31/07 Customer Level	494,127,000	494,127,000	
8	Adjusted Test Year Retail Sales	29,220,052,000	29,220,052,000	
9	Pro Forma Adjustment to Fuel and Purchased Power Expense	$ 129,649,371	$ 97,331,993	$ (32,317,378)

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			Per Staff Direct Filing		
10	Normalized Fuel and Purchased Costs	3.8783	3.7677		
11	Existing base fuel rate	3.2491	3.2491		
12	Increase above current base cost of fuel	0.6292	0.5186		($000)
13	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 151,535,190	$ (32,328,581)	$(32,329)
14	Related reduction in PSA revenue	$ 169,987,454	$ 140,098,732	$ (29,888,722)	$(29,889)
15	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,436,458	$ (2,439,859)	$ (2,440)
16	Rounded to thousands	$ 13,876	$ 11,436	$ (2,440)	

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			PER SETTLEMENT		
17	Related reduction in PSA revenue	169,987,454.0000	3.7571	**Per APS's PSA filing**	
18	Existing base fuel rate	3.2491	3.2491		
19	Increase above current base cost of fuel	169,987,450.7509	0.5080		($000)
20	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 148,437,864	$ (35,425,907)	$(35,426)
21	Related reduction in PSA revenue	$ 169,987,454	$ 137,235,163	$ (32,752,291)	$(32,752)
22	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,202,701	$ (2,673,616)	$ (2,674)
23	Rounded to thousands	$ 13,876	$ 11,203	$ (2,673)	
24	Difference from Staff direct filing		$ (233)	$ (233)	

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

TESTIMONY SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JULY 01, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 2

III. Rate Increase 2

IV. Cost of Capital and Fair Value Rate of Return 9

V. Depreciation 10

VI. Fuel and Power Supply Adjustment Provisions 11

VIII. Equity Infusions into APS 12

IX. Pension and OPEB Deferrals 13

X. Treatment of Schedule 3 14

XI. Adjustment to Depreciation Rates for Palo Verde License Extension 15

ATTACHMENTS

Calculation of Base Cost of Fuel and Purchased Power RCS-8

EXECUTIVE SUMMARY
TESTIMONY IN SUPPORT OF SETTLEMENT OF RALPH C. SMITH
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My testimony in support of the Settlement addresses the following sections of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

A summary of my testimony concerning the Settlement Agreement for each of these areas follows:

III. Rate Increase.

For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue is approximately $196.3 million, plus $11.2 million for a fuel related increase in base rates, plus $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion.

Settlement paragraph 3.8 shows how the base rate increase provided for in the Settlement compares with various Signatories' initial proposed increases. It has columns for APS's original filing, Staff's direct filing, Residential Utility Consumer Office's ("RUCO") direct filing, Arizonan for Electric Choice and Competition's ("AECC") direct filing, and the Settlement. The $344.7 million total rate increase is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

In addition to the amount of base rate increase, the Settlement Agreement also provides for exceptional accounting treatments for APS for Pension and Other Post and Employee Benefit ("OPEB") deferrals (in Section IX), for treating Schedule 3 receipts as revenue (in Section X) and for an adjustment to Palo Verde depreciation rates for a License Extension (in Section XI). Each of these special accounting provisions has future rate consequences for APS ratepayers.

IV. Cost of Capital and Fair Value Rate of Return

The Settlement Agreement at paragraphs 4.1 through 4.3 provides for an overall cost of capital of 8.58 percent and a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A. It provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Additionally, as explained on page 8 of Staff witness Johnson's direct testimony, as a matter of policy Staff proposed a fair value rate of return ("FVROR") that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB"). This 1.5 percent return was incorporated into the FVROR for Settlement Purposes, as shown on line 9 of Settlement Attachment A. As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with an additional base rate increase of $51.265 million.

V. Depreciation

Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent.

VI. Fuel and Power Supply Adjustment Provisions

Section VI of the Settlement Agreement addresses the provisions of the Purchased Power Fuel Adjustor Clause that has been agreed to by the parties through the process of negotiation. As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued. The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates. Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism. The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

VIII. Equity Infusions into APS

As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014. This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009. Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. Pension and OPEB Deferrals

Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs in 2011 and 2012 if such costs exceed the test year level, which the parties to the Settlement Agreement have identified as $23.949 million. Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

X. Treatment of Schedule 3

Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. Currently, APS records Schedule 3 receipts as Contributions in Aid to Construction ("CIAC"). As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment. Another witness for Staff, Ernest Johnson, is addressing the policy reasons for this treatment.

XI. Adjustment to Depreciation Rates for Palo Verde License Extension

Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Paragraph 11.1 also provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension.

As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. During that period, the lower recorded depreciation expense amounts mean that Accumulated Depreciation (a rate base offset) would be lower and APS' rate base in the next rate case would be higher.

As with the other aspects of the Settlement Agreement that involved compromises from Staff's normal litigation position on such issues, Staff witness Ernest Johnson is addressing the policy reasons for this treatment in the context of the Settlement Agreement.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding?

A. Yes.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment RCS-8 presents an update of Staff Schedule C-15 showing additional details for the adjustment to fuel and purchased power expense.

Q. What is the purpose of your testimony in support of the settlement?

A. The purpose of my testimony in support of the settlement is to explain the derivation of the base rate increase, some of the figures, and some of the other accounting treatments that are provided for in the Settlement. The base rate increase provided for in the Settlement is strictly for purposes of this Settlement and should not be viewed as necessarily representing positions that Staff would be advocating in any other situation. All of the Staff policy decisions related to the Settlement are addressed in the testimony of Staff witness Ernest Johnson.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your testimony?

A. My testimony addresses aspects of the following provisions of the Settlement Agreement:

III. Rate Increase

IV. Cost of Capital

V. Depreciation

VI. Fuel and Power Supply Adjustment Provisions

VIII. Equity Infusions to Be Made by APS

IX. Pension and OPEB Deferrals

X. Treatment of Schedule 3

XI. Adjustment of Depreciation Rates for Palo Verde License Extension

The numbering of these provisions in my testimony corresponds with the Settlement Agreement.

III. RATE INCREASE

Q. For Settlement purposes, to what amount of base rate increase did the signing parties agree?

A. For Settlement purposes, Staff, Arizona Public Service ("APS"), and a number of other parties to this rate case have agreed to a rate increase that would provide APS with approximately $344.7 million of base rate revenue per year. As shown in the Settlement Agreement, page 13, paragraph 3.8, this $344.7 million is approximately a 13 percent increase over APS's current revenue of $2.637 billion. In dollar terms, the base rate increase over APS's current revenue of $344.7 million is the sum of three components: (1) a non-fuel related base rate increase of approximately $196.3 million; (2) approximately $11.2 million for a fuel related increase in base rates; and (3)

approximately $137.2 million for the adjusted base cost of fuel related increase. This is also addressed in paragraph 3.2 through 3.6 of the Settlement.

Q. What fair value rate base and fair value rate of return did the signing parties agree to for Settlement purposes?

A. As described in paragraph 3.5 of the Settlement, the parties agreed to an Arizona jurisdictional fair value rate base for the test year ending December 31, 2007, of approximately $7.666 billion. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR") as shown on Settlement Attachment A.

Q. How does the amount of revenue increase provided for in the Settlement Agreement compare with what APS, Staff and other signatories had originally proposed?

A. A table shown on Settlement page 13, paragraph 3.8 (which is reproduced below for ease of reference) summarizes the base rate and total rate increase that APS, Staff, Residential Utility Consumer Office ("RUCO") and Arizonan for Electric Choice and Competition ("AECC") each had originally recommended, and shows the corresponding Settlement amounts:

Comparison of APS, Staff, RUCO and Settlement Summary of Base Rate Increase (Thousands of Dollars)	APS Proposed	Staff Proposed	RUCO Proposed	AECC Proposed	Settlement
Components of Total Rate Increase					
Base Rate Increase	$ 264,341	$ 155,062	$ (27,281)	$ 205,444	$ 196,300
Fuel Related Increase in Base Rates	$ 13,876	$ 11,436	$ 13,876	$ 10,695	$ 11,203
Total Base Rate Increase	$ 278,217	$ 166,498	$ (13,405)	$ 216,139	$ 207,503
Adjusted Base Cost of Fuel Related Increase	$ 169,977	$ 140,088	$ 169,977	$ 130,527	$ 137,235
Total Rate Increase Requested	$ 448,194	$ 306,586	$ 156,572	$ 346,666	$ 344,738
Percentage Increase Over Current Rates					
Revenue from Sales to Ultimate Retail Customers 2007 Test Year Adjusted	$ 2,637,447	$ 2,637,447	$ 2,748,697	$ 2,637,447	$ 2,637,447
Percentage Increase - Net of PSA	10.55%	6.31%	-0.49%	8.20%	7.87%
Percentage Increase - Total	16.99%	11.62%	5.70%	13.14%	13.07%
Revenue from Sales to Ultimate Retail Customers 2010 Base Rate Revenue per APS	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236	$ 2,654,236
Percentage Increase - Net of PSA	10.48%	6.27%	-0.51%	8.14%	7.82%
Percentage Increase - Total	16.89%	11.55%	5.90%	13.06%	12.99%

The $344.7 million total rate increase provided for in the Settlement is below the amounts recommended in APS' and AECC's direct filings, and is above the amounts recommended in Staff's and RUCO's direct filings.

Q. Has a portion of the amount of base rate increase provided for in the Settlement already been implemented by APS?

A. Yes. A portion of the base rate increase had already been put into effect when the Commission granted APS an interim increase of $65.2 million in 2008.

Q. Referring to the above table, please explain briefly how the Settlement "base rate increase" amount of $196.3 million was derived.

A. The "base rate increase" of $196.3 million was arrived at through lengthy negotiations between the Signatories over the past 5-6 months. Staff witness Ernest Johnson's testimony in support of the Settlement explains the policy considerations involved. In dollar terms, the following presents a rough synopsis of the $196.3 million base rate

revenue increase provided for in the Settlement, starting from the recommendation in Staff's direct testimony filing:

Approximate Derivation of the $196.3 Million
(Amounts in Millions)

Line No.	Description	Revenue Requirement Amount (Decrease) Increase	Reference
1	Staff base rate revenue increase	$ 155.1	Attachment RCS-2, Sch A, p.2, Col.B, L.9
	Supplemental:		
2	Remove APS adjustment for DSM Lost Revenue aka Uncollected Fixed Costs	$ (15.7)	R Smith Supplemental Direct filed 1-9-2009
	Corrections:		
3	Yucca Units 5 & 6	$ 1.0	Settlement Negotiations
4	Income Tax Calculation/Interest Synchronization	$ 7.4	Settlement Negotiations
	Additions:		
5	Additional Post Test Year Plant	$ 48.6	Settlement Negotiations
6	**Base rate revenue increase per Settlement**	**$ 196.3**	Settlement Negotiations (sum of Lines 1-5)*

*Numbers may not add exactly due to rounding.

Q. Please briefly explain the adjustment to remove the APS adjustment for DSM Lost Revenue also know as Uncollected Fixed Costs.

A. This adjustment was addressed in my supplemental testimony, filed on January 9, 2009. APS witness Ewen's Attachment PME-13 (filed with his direct testimony) and described in his direct testimony at page 33, shows that APS had proposed to reduce test year operating revenue by $16.789 million for 220,696 MWh of lost sales, and to reduce related operating expenses by $1.052 million, for a net reduction to pre-tax operating income of $15.738 million. In Docket No. E-01345A-05-0816 et al, APS had proposed a pro forma adjustment for estimated 2006 lost revenues from DSM programs in conjunction with a test year ended September 30, 2005, i.e., approximately 1.25 years beyond the test year. In the current case, APS has proposed a pro forma adjustment for estimated 2010 lost revenue from DSM programs in conjunction with a 2007 test year,

i.e., three years beyond the test year. In Decision No. 69663, the Commission had rejected the similar adjustment proposed by APS in that rate case. As I had stated in my supplemental testimony (at page 3):

> The approximate impact from APS' proposed adjustment no. 13 to the revenue requirement is $15.7 million. ... Unless APS provides a compelling argument for this adjustment, including a strong argument why a conclusion different than Decision No. 69663 is required, Staff will reverse APS proposed adjustment no. 13 when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing.

The Settlement Agreement revenue requirement reflects this reduction of $15.7 million to reverse APS' proposed adjustment for DSM lost revenues also known as Unrecovered Fixed Charges.

Q. Please briefly explain the correction items to Staff's direct-filed revenue requirement.

A. It was brought to my attention that there were two errors in the calculation of Staff's revenue requirement. The first item related to including in jurisdictional rate base the cost of a step-up transformer for Yucca Units 5 and 6 and reflected actual costs incurred for plant balances through 12/31/08 as opposed to 09/30/08 actual costs incurred. The second item related to a correction to Staff's interest synchronization calculation for the amount "per APS' filing"[1] to take into account the interest synchronization that was reflected by the Company in each individual pro forma adjustments on APS Schedule C-2. These two corrections to Staff's revenue requirement were accepted by Staff and the other Signatories in Settlement discussions, and were reflected in deriving the amount of base rate increase that is provided for in the Settlement.

[1] See, Attachment RCS-2, Schedule C-13, line 4, as filed with my direct testimony.

Q. Please briefly explain the adjustment for additional post test year plant.

A. The additional $48.6 million represents one way of deriving an adjustment to the revenue requirement to provide rate recognition for additional APS post-test year plant additions through June 30, 2009, i.e., for a period of 18 months beyond the 2007 test year. Staff witness Ernest Johnson's testimony in support of the settlement explains the reasons for why Staff agreed to including this for purposes of deriving the amount of revenue increase provided for in the Settlement.

Q. The next item in the Settlement Agreement, paragraph 3.8, in the "Settlement" column, is $11.203 million for a "Fuel Related Increase in Base Rates." Can you please briefly explain that item?

A. Yes. This item is comparable to the $11.436 million shown in the "Staff Proposed" column.[2] When the Company's Base Cost of Fuel is reestablished in a base rate case, this impacts the amounts that APS can recover through its Power Supply Adjustor ("PSA") mechanism, which has a 90/10 sharing provision.[3] The reestablishment of a higher Base Cost of Fuel in this case allows APS to recover in base rates approximately $11.203 million more than APS would have been able to recover in increased fuel and purchased power costs solely through the operation of the PSA.

Staff's adjustment for the Base Cost of Fuel was presented on Attachment RCS-2, Schedule C-15, filed with my direct testimony. In that adjustment, Staff had used a base cost of fuel of 3.7677 cents per kWh. The Settlement Agreement (at paragraph 6.2) provides for a slightly lower Base Cost of Fuel of 3.7571 cents per kWh. This difference in the Base Cost of Fuel is attributed to the decrease of approximately $233,000 from the

[2] This amount also appears on Attachment RCS-2 (to my direct testimony), Schedule A, page 1, line 9, and page 2, line 10.

[3] Per Settlement Agreement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued for purposes of the resolution of this rate case.

$11.436 million in Staff's direct filing to the $11.203 million provided for in the Settlement.

Q. Have you prepared an update to Staff Schedule C-15 that shows this?

A. Yes. Attachment RCS-8 to my testimony in support of the Settlement updates Staff Schedule C-15, and includes some additional calculation detail, showing the derivation of the $11.203 million Settlement amount and the $11.436 million amount from Staff's direct filing.

Q. Please briefly explain the "Adjusted Base Cost of Fuel Related Increase" of $137.235 million that appears in the Settlement Agreement, paragraph 3.8 table.

A. The $137.235 million represents the amount of fuel and purchased power cost increase that is now to be included in APS' base rates, at the Base Cost of Fuel of 3.7571 cents per kWh. Were it not for the base rate case, APS would have recovered this amount of fuel and purchased power cost increase through the operation of its PSA. The derivation of the $137.235 million is also shown on Attachment RCS-8.

Q. What average percentage increase in base rates does the revenue increase of $344.738 million represent?

A. As shown in the Settlement Agreement at paragraph 3.8, this represents an average increase of approximately 13.07 percent over the adjusted 2007 test year base rate revenue.

Q. Are there other provisions in the Settlement Agreement that would result in future rate increases to APS customers?

A. Yes. As described in the Settlement at paragraph 3.9, APS has various adjustor mechanisms, which are estimated to produce net additional rate increases. Staff witness Barbara Keene's testimony in support of the settlement addresses those mechanisms. Additionally, as described in the Settlement at paragraph 3.10, there are other provisions of the Settlement which do not have a rate impact in the present case, but will have an impact in future APS rate cases. I address some of those items in subsequent sections of my testimony in support of the Settlement.

IV. COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. Please refer to paragraphs 4.1 and 4.2 of the Settlement Agreement. What is the source for the capital structure and cost rates?

A. The source for the capital structure and cost rates specified in paragraphs 4.1 and 4.2 of the Settlement Agreement is the agreement of the Signatories. These amounts can also be found in Staff's direct filing at Attachment RCS-2, Schedule D, lines 5-8, and produce a weighted cost of capital of 8.58 percent.

The Settlement Agreement provides for a return on equity of 11.0 percent, which was the Staff recommendation. The 11.0 percent was at the high end of the range from 9.0 percent to 11.0 percent recommended by Staff witness David Parcell. Staff witness Ernest Johnson's direct testimony, at page 8, explained that Staff's use of the high end of Mr. Parcell's recommended range was intended to aid APS in its efforts to secure access to capital.

Q. Please refer to paragraph 4.3 of the Settlement Agreement. How was the 6.65 percent calculated?

A. The Settlement Agreement at paragraph 4.3 provides for a 6.65 percent fair value rate of return ("FVROR"), which is calculated as shown on Settlement Attachment A.

As explained on page 8 of Staff witness Johnson's direct testimony, as a policy decision in this case, Staff had proposed a revenue requirement for APS using a FVROR that recognized a 1.5 percent return to the difference between Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB").

As shown on Attachment RCS-2 to my direct testimony, Schedule A, page 2, column B, line 8, applying this FVROR to the FVRB provided APS with a base rate increase of $51.265 million that was in addition to the OCRB-based calculation. This 1.5 percent return was also incorporated into the FVROR for Settlement Purposes, as shown on line 9, of Settlement Attachment A.

V. DEPRECIATION

Q. Please address the depreciation rates provided for in the Settlement Agreement at Section V.

A. Section V of the Settlement Agreement addresses depreciation rates. It provides that APS shall use the depreciation rates contained in Attachment REW-1 to APS witness Ronald White's direct testimony, with the exception of Account 370.01, Electronic Meters, for which APS will continue to use the existing depreciation rate of 3.68 percent. This treatment is consistent with the recommendations made concerning depreciation rates in the Staff direct filing.

VI. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

Q. Please address the Fuel and Power Supply Adjustment provisions provided for in the Settlement Agreement at Section VI.

A. Section VI of the Settlement Agreement addresses the provisions of the PSA that have been agreed to by the Signatories through the process of negotiation.

As provided for in Settlement paragraph 6.1, the 90/10 sharing provision in the current PSA will be continued.

The Base Cost of Fuel and Purchased Power is $0.037571 cents per kWh and shall be reflected in APS' base rates.

Gains on SO_2 allowances over or under the normalized jurisdictional test year amount reflected in base rates of $7.045 million shall be recovered or refunded through the PSA mechanism.

The PSA Plan of Administration will be amended to reflect the terms of the Agreement.

Q. How does the Base Cost of Fuel and Purchased Power of 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 compare with APS' and Staff's direct filings?

A. The 3.7571 cents per kWh provided for in the Settlement at paragraph 6.2 corresponds to the forward-looking PSA rate currently in effect for APS. It is lower than both the 3.8783 cents per kWh used by APS in its direct filing and the 3.7677 cents per kWh from Staff's direct filing. It thus reflects, at least in part, the lower cost of fuel that APS has been experiencing recently.

Paragraph 2.6 of the Settlement Agreement provides for the possibility of an accelerated PSA reset at the time new base rates are implemented if APS's fuel and purchased power costs result in a PSA over-collected balance at that time.

Q. Please explain the Settlement treatment of the Gain on Sale of SO_2 Allowances.

A. The Settlement Agreement at paragraph 6.3 provides that Gains on SO_2 Allowance sales over or under the normalized jurisdictional test year amount shall be recovered and/or refunded through the PSA mechanism.

Staff's derivation of the proposed revenue increase had reflected a normalized amount of Gains on the Sale of SO_2 Allowances of approximately $7.045 million as an offset to the test year expenses[4] (which in turn reduced the amount of the base rate revenue increase). Staff's recommendation was also that annual fluctuations above or below the amounts reflected in base rates for Gains on the Sale of SO_2 Allowances should be reflected as adjustments to PSA-includable costs. The Settlement provides for 100 percent of the annual Gains on the Sale of SO_2 Allowances to be credited in the PSA against PSA includable costs. Crediting such gains through the PSA is appropriate and reasonable because Gains on the Sale of SO_2 Emission Allowances are closely related to the amount of coal burned at APS's generating plants, can be significant in amount, and can fluctuate significantly from year to year.

VIII. EQUITY INFUSIONS INTO APS

Q. Please discuss the Settlement provisions for equity infusions into APS.

A. As provided in Settlement paragraph 8.1, APS agrees to complete equity infusions of at least $700 million during the period beginning June 1, 2009 through December 31, 2014.

[4] See Attachment RCS-2, Schedule C-14, Column B, line 1, as filed with my direct testimony.

This amount includes the "up to $400 million" previously authorized by the Commission in Decision No. 70454, which authorization expires on December 31, 2009.

Equity infusions are an important component of APS using its best efforts to maintain investment grade financial ratios and a balanced capital structure, and its efforts to improve its existing ratings with the financial rating agency community.

IX. PENSION AND OPEB DEFERRALS

Q. Please discuss the Settlement provisions for Pension and Other Post Employment Benefit ("OPEB") deferrals.

A. Section IX of the Settlement Agreement provides for limited deferrals of Pension and OPEB costs by APS in 2011 and 2012 if such costs exceed the test year level, which the Signatories to the Settlement Agreement have identified as $23.949 million.

Deferrals of Pension and OPEB costs that occur under such provisions of the Settlement would present an additional cost to APS' ratepayers in a future rate case. The total additional cost to ratepayers from this provision could be as much as $42.5 million (if the maximum deferrals in 2011 of $13.5 million and 2012 of $29 million occur).

The annual impact to APS ratepayers would depend upon the amortization period selected in a future APS next rate case. For illustrative purposes, if a five-year amortization period were to be used, and the deferrals reached the maximum amount of $42.5 million, the annual impact on APS ratepayers would be approximately $8.5 million of additional rate increase per year.[5] If a seven-year amortization period were to be used, the annual impact

[5] $42.5 million / 5 years

on APS ratepayers would be approximately $6.1 million of additional rate increase per year.[6]

Another witness for Staff, Ernest Johnson, is addressing the policy reasons for why Staff has agreed to provide APS with the deferred accounting treatment.

X. TREATMENT OF SCHEDULE 3

Q. How does APS currently account for Schedule 3 receipts?

A. Currently, APS records Schedule 3 receipts as Contributions in Aid of Construction ("CIAC").

Q. How is CIAC typically treated for ratemaking purposes?

A. CIAC is typically treated for ratemaking purposes as an offset to rate base. The rate base offset amount related to CIAC is typically based on the unamortized CIAC balance, less an income tax impact that is accounted for in the balance of Accumulated Deferred Income Taxes ("ADIT").

As a simplified example, if a utility had $100 million of unamortized CIAC (and there was a 40 percent combined state and federal income tax rate), rate base would be reduced by approximately $60 million ($100 million of CIAC less $40 million of ADIT).

The amortization of CIAC is typically reflected for ratemaking purposes as an offset to a utility's depreciation expense.

[6] $42.5 million / 7 years

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Does accounting for Schedule 3 receipts as revenue during this period have future rate consequences?

A. Yes. Recording Schedule 3 receipts as revenue, rather than as CIAC, will have consequences for APS' ratepayers in a future rate case. All other things being equal, rate base in a future APS rate case would be higher because of this treatment.

Q. Is it possible to estimate the increased rate base, post-2012, that would result from APS' accounting for Schedule 3 receipts as revenue during the period, 2010 through 2012?

A. Not reliably. The amounts identified by APS for 2010-2012 sum to $97 million. The rate base increase would be approximately the sum of the Schedule 3 amounts for 2010-2012 that APS accounted for as revenue, rather than as CIAC, less the related ADIT impact.

XI. ADJUSTMENT TO DEPRECIATION RATES FOR PALO VERDE LICENSE EXTENSION

Q. Has APS applied for a Palo Verde license extension?

A. Yes. APS has applied for a license extension for the Palo Verde nuclear generating plant.

Q. How would APS' depreciation rates be impacted by a Palo Verde license extension?

A. The cost of the plant is being depreciated over the remaining period of the license. With a license extension, the remaining cost of the plant would be depreciated over a significantly longer period, and the result would be significantly lower depreciation rates.

Q. Where are the anticipated new depreciation rates related to a Palo Verde life extension specified in the Settlement Agreement?

A. Attachment B to the Settlement Agreement, at pages 5-6, shows the current and proposed depreciation rates for Nuclear Production, by unit, that APS estimates would result from the Palo Verde license extension.

Q. Are the new depreciation rates related to a Palo Verde life extension significantly lower than the present Palo Verde depreciation rates?

A. Yes. Referring to Settlement Agreement Attachment B, for example, at page 5 of 8, APS' current depreciation rate for Palo Verde, on a composite basis, is 2.80 percent. With a license extension, the Palo Verde composite depreciation rate[7] would drop to 1.36 percent. In other words, the composite depreciation rate for Palo Verde in total would be cut by more than half, as a result of reflecting the impact of the license extension.

Q. How is the implementation of new depreciation rates by a utility typically coordinated with the ratemaking process?

A. Typically, the implementation of new depreciation rates is coordinated with the ratemaking process by having new depreciation rates be implemented at the same time that a utility's new base rates become effective.

Q. Why is that coordination of new depreciation rates in the ratemaking process usually considered important?

A. Depreciation expense is a significant component of a utility's cost of service. Coordinating the implementation of new depreciation rates, especially where the new rates represent significant changes from the existing rates, with changes in the utility's base

[7] As shown in the Settlement Agreement, Attachment B, APS does not apply depreciation rates for its generating units on a composite basis; rather, APS applies such depreciation rates by unit and by type of plant.

rates for utility service helps assure that the Depreciation Expense and Accumulated Depreciation that the utility records on its books is coordinated with the rates that ratepayers are paying for utility service. Accumulated Depreciation is a significant offset to a utility's rate base.

Q. How does the Settlement Agreement provide for the implementation by APS of new, significantly lower depreciation rates related to a Palo Verde life extension?

A. Section XI of the Settlement Agreement at paragraph 11.1 provides for APS to record lower depreciation expense on Palo Verde to reflect the impact of a license extension that APS anticipates. APS would implement the lower Palo Verde depreciation rates upon the later date of (1) receiving Nuclear Regulatory Commission ("NRC") approval for the Palo Verde license extension, or (2) January 1, 2012.

Q. How is this provision intended to benefit APS?

A. As explained in paragraph 11.3, allowing APS to implement new, lower depreciation rates before the Company's base rates for electric service are reestablished in the Company's next rate case is intended to represent a benefit to APS. APS' reported earnings would be improved by recording lower depreciation expense for some period before the lower depreciation expense is recognized in the establishment of customer rates for electric service.

Q. How could this provision in the Settlement result in higher future costs to APS' ratepayers?

A. It could result in a higher rate base from a lower amount of Accumulated Depreciation compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect. Specifically, APS would be recording

lower Palo Verde Depreciation Expense before lower recorded depreciation expense amounts are recognized in the ratemaking process. During that period, the amount of Accumulated Depreciation (a rate base offset) recorded by APS would be lower and, consequently, APS' rate base in a future rate case (or cases) would be higher than compared to a situation when the new depreciation rates were implemented at the same time as the utility's new base rates went into effect.

Q. When would APS ratepayers start to benefit from the lower Palo Verde depreciation expense?

A. Ratepayers would start to benefit from the lower Palo Verde depreciation expenses once APS' base rates were adjusted in a future rate case to reflect the impact of this reduced expense.

Q. Would a Palo Verde life extension affect any other expenses?

A. Yes. Other things being equal, a Palo Verde life extension would also be expected to significantly reduce APS' nuclear decommissioning expense.

Q. How does the Settlement Agreement provide for recognizing the impact of decreased decommissioning expense?

A. The Settlement Agreement at paragraph 11.1 provides that APS shall file a request that the Commission reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the Palo Verde license extension. Moreover, it is the Signatories' intention that the reduction in decommissioning expense be passed onto APS' ratepayers, via a reduction to the SBC, concurrently with when APS begins to record the lower Palo Verde depreciation expense on its books.

Q. Does this conclude your Testimony?

A. Yes, it does.

Arizona Public Service Company
Base Fuel and Purchased Power

Test Year Ended December 31, 2007

Attachment RCS-8
Docket No. E-01345A-08-0172
Schedule C-15
Page 1 of 1

UPDATED FOR SETTLEMENT

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)	Reference
1	Adjustment to Base Fuel and Purchased Power	$ (32,317,378)	$ (32,317,378)	A
1a	**PER SETTLEMENT**	**$ (35,425,907)**	**$ (35,425,907)**	
1b	Difference	$ (3,108,529)	$ (3,108,529)	

Notes and Source

A: Per APS Witness Ewen Attachment PME-3 and APS' supplemental response to Staff ___

	Adjusted Test Year Fuel and Purchased Power Costs (cents per kWh)	Per APS	Per Staff	Adjustment
2	Normalized Fuel and Purchased Costs	3.8783	3.7677	
3	Test Year Fuel and Purchased Power Costs	3.4346	3.4346	
4	Difference	0.4437	0.3331	
	Adjusted Test Year Retail Sales (MWh)			
5	Test Year Retail Sales (MWh)	29,171,321,000	29,171,321,000	
6	Pro Forma Adjustment to Normalize Weather	(445,396,000)	(445,396,000)	
7	Pro Forma Adjustment to Annualize 12/31/07 Customer Level	494,127,000	494,127,000	
8	Adjusted Test Year Retail Sales	29,220,052,000	29,220,052,000	
9	Pro Forma Adjustment to Fuel and Purchased Power Expense	$ 129,649,371	$ 97,331,993	$ (32,317,378)

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			Per Staff Direct Filing		
10	Normalized Fuel and Purchased Costs	3.8783	**3.7677**		
11	Existing base fuel rate	3.2491	3.2491		
12	Increase above current base cost of fuel	0.6292	0.5186		($000)
13	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 151,535,190	$ (32,328,581)	$(32,329)
14	Related reduction in PSA revenue	$ 169,987,454	$ 140,098,732	$ (29,888,722)	$(29,889)
15	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,436,458	$ (2,439,859)	$ (2,440)
16	Rounded to thousands	$ 13,876	$ 11,436	$ (2,440)	

ESTIMATED IMPACT OF FUEL AND PURCHASED POWER ABOVE CURRENT BASE COST OF FUEL
IMPACT ON PSA REVENUE

			PER SETTLEMENT		
17	Related reduction in PSA revenue	169,987,454.0000	**3.7571**	**Per APS's PSA filing**	
18	Existing base fuel rate	3.2491	3.2491		
19	Increase above current base cost of fuel	169,987,450.7509	0.5080		($000)
20	Increase in fuel cost above existing base fuel rate	$ 183,863,771	$ 148,437,864	$ (35,425,907)	$(35,426)
21	Related reduction in PSA revenue	$ 169,987,454	$ 137,235,163	$ (32,752,291)	$(32,752)
22	Increase in fuel cost that would not be subject to recovery in PSA	$ 13,876,317	$ 11,202,701	$ (2,673,616)	$ (2,674)
23	Rounded to thousands	$ 13,876	$ 11,203	$ (2,673)	
24	Difference from Staff direct filing		$ (233)	$ (233)	

ALL-STATE LEGAL®
EXHIBIT
S-12
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

SUPPORTING THE SETTLEMENT AGREEMENT

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 01, 2009

TABLE OF CONTENTS

Page

Introduction 1

Settlement Agreement 2

Fuel and Power Supply Adjustment Provisions 2
Treatment of Schedule 3 2
Demand-side Management 4
Renewable Energy 9

APPENDICES

Appendix 1 ..... Resume of Barbara Keene

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

This testimony addresses provisions of the Settlement Agreement, including Power Supply Adjustment Plan of Administration, Treatment of Schedule 3, withdrawal of APS' Impact Fee proposal, withdrawal of APS' System Facilities Charge proposal, revisions to Schedule 3, Demand-side Management, and Renewable Energy.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst Manager. My duties include supervising the energy portion of the Telecommunications and Energy Section. A copy of my résumé is provided in Appendix 1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01345A-08-0172?

A. Yes.

Q. What is the subject matter of this testimony?

A. This testimony will provide support for the Settlement Agreement ("Agreement") filed on June 12, 2009, by addressing the following sections of the Agreement:

Section VI.	Fuel and Power Supply Adjustment Provisions
6.4	Plan of Administration
Section X.	Treatment of Schedule 3
10.5	withdrawal of APS' Impact Fee proposal
10.6	withdrawal of APS' System Facilities Charge proposal
10.7	revisions to Schedule 3
Section XIV.	Demand-side Management
Section XV.	Renewable Energy

SETTLEMENT AGREEMENT

Fuel and Power Supply Adjustment Provisions

Q. What does the Agreement contain in regard to Power Supply Adjustment ("PSA")?

A. Section VI of the Agreement provides for some modifications to the PSA of Arizona Public Service Company ("APS"). Subsection 6.4 provides that the PSA Plan of Administration would be amended to reflect those modifications, and the Plan of Administration would be approved by the Commission concurrent with approval of the Agreement.

Q. Please describe the revisions to the PSA Plan of Administration.

A. The revisions will include adding reference to gains on SO_2 allowances, updating the base cost of fuel and purchased power, and removing outdated language.

Q. Was the revised PSA Plan of Administration filed with the Agreement?

A. No, APS has filed a revised PSA Plan of Administration on June 29, 2009.

Q. When does Staff expect to complete its review of the revised PSA Plan of Administration?

A. Staff expects to complete its review of the revised PSA Plan of Administration after this testimony has been filed and would therefore address it in reply testimony

Treatment of Schedule 3

Q. What does the Agreement contain in regard to Schedule 3?

A. Section X of the Agreement contains provisions regarding APS' line extension policy ("Schedule 3"). This testimony covers subsections 10.5, 10.6, and 10.7. Other Staff witnesses will discuss policy and treatment of proceeds.

Q. What is included in subsection 10.5?

A. APS had included a proposal for an Impact Fee in its rate case application. APS had described the purpose of the Impact Fee as allowing APS to recover certain growth-related expenses either caused by Schedule 3 or not recovered by Schedule 3. Subsection 10.5 of the Agreement provides for APS to withdraw the proposed Impact Fee. However, APS would be allowed to discuss impact or hook-up fees in the Commission's generic docket on hook-up fees.

Q. What is included in subsection 10.6?

A. APS had included a proposed System Facilities Charge in the Schedule 3 included in its rate case application. The purpose of the System Facilities Charge was to recover the costs associated with improvements to APS facilities necessary to support APS' aggregated load serving and voltage regulation requirements as a result of new growth. Subsection 10.6 of the Agreement provides for APS to withdraw the proposed System Facilities Charge.

Q. What is included in subsection 10.7?

A. Subsection 10.7 provides for APS to make some modifications to Schedule 3 to enhance clarity and provide transparency of costs.

Q. Please describe the modifications.

A. The term "Local Facilities" will be defined so as to make clear what type of facilities are included in the line extension cost estimates provided to customers. In addition, APS will be itemizing those cost estimates. There will be language in Schedule 3 to express the current practice of allowing customers to hire contractors for trenching, conduit, and backfill necessary for underground extensions. Schedule 3 will contain procedures for

refunding amounts to customers when additional customers connect to a line extension. Furthermore, Schedule 3 will contain a Schedule of Charges so that customers will know what the charges will be for specific items and that the charges are consistently applied to all customers seeking a line extension. The Schedule of Charges would be approved by the Commission when the revised Schedule 3 is approved concurrent with approval of the Agreement.

Q. Was the revised Schedule 3 filed with the Agreement?

A. No, APS has filed the revised Schedule 3 on June 29, 2009.

Q. When does Staff expect to complete its review of the revised Schedule 3?

A. Staff expects to complete its review of the revised Schedule 3 after this testimony has been filed and would therefore address it in reply testimony.

Demand-side Management

Q. What does the Agreement contain in regard to demand-side management ("DSM")?

A. Section XIV of the Agreement provides for energy efficiency goals (14.1), a modified performance incentive (14.2), self-direction (14.3-14.5), a modified DSMAC (14.6-14.7), no recovery of unrecovered fixed costs in this rate case (14.8), annual Implementation Plans (14.9-14.10), and components of the 2010 Implementation Plan (14.11).

Q. What is energy efficiency?

A. Energy efficiency is a type of DSM that consists of products, services, or practices aimed at saving energy in end-use applications generally by substituting technically more advanced (compared to what is presently used in a specific situation) equipment or

practices to produce the same or an improved level of end-use service with less energy use.

Q. Please describe the energy efficiency goals contained in the Agreement.

A. APS would have to meet energy efficiency goals defined as annual energy savings expressed as a percent of total energy resources needed to meet retail load. The goals are shown in Table 1. If the Commission were to adopt higher energy efficiency goals in another docket, the higher goals would supersede the goals in the Agreement.

Table 1
Energy Efficiency Goals

Year	Energy Savings as % of Total Energy Resources	Cumulative Energy Savings
2010	1.00 %	1.00 %
2011	1.25 %	2.25 %
2012	1.50 %	3.75 %

Q. Please describe the modified performance incentive.

A. The performance incentive allows customers and the utility to share the overall net benefits of the energy efficiency portfolio. Currently, customers receive 90 percent and APS receives 10 percent of the net benefits of energy efficiency programs up to a cap of 10 percent of reporting period DSM spending. Under the Agreement, the performance incentive becomes tiered, relative to achieving levels of the energy efficiency goals. See Table 2.

Table 2
Tiered Performance Incentive

% of Energy Efficiency Goal Achieved	Performance Incentive as % of Net Benefits	Performance Incentive Capped at % of Program Costs
< 85 %	0 %	0 %
85 % - 95 %	6 %	12 %
96 % - 105 %	7 %	14 %
106 % - 115 %	8 %	16 %
116 % - 125 %	9 %	18 %
> 125 %	10 %	20 %

Q. What is Self Direction?

A. Self Direction is an option made available to large customers who choose to reserve their DSM contributions for funding projects at their own facilities.

Q. What does the Agreement provide in regard to Self Direction?

A. The Agreement provides for commercial or industrial customers who use more than 40 million kWh per year (based on aggregation of all of the customer's accounts) to Self Direct 85 percent of the customer's DSM contributions. Details of the Self Direction option are included in Attachment C of the Agreement.

Q. What is the DSMAC?

A. The DSMAC ("Demand-side Management Adjustor Clause") is the adjustor mechanism through which APS recovers prudently incurred DSM program and related costs incurred by APS, above the $10 million included in base rates, in connection with Commission-approved DSM programs and activities. Allowable costs include costs for rebates or other incentives, including rebate processing; training and technical assistance; customer education; program planning and administration; program implementation; marketing and

communications; monitoring and evaluation; and baseline studies. APS also is allowed to collect the performance incentive discussed above. APS currently collects DSM costs through the DSMAC after the costs are incurred.

Q. How would the Agreement modify the DSMAC?

A. The Agreement provides for APS' DSMAC to be modified to allow for more current recovery of DSM costs, similar to the DSM adjustor approved for Tucson Electric Power in Decision No. 70628.

Q. How would the DSMAC rate be calculated?

A. The total amount to be recovered through the DSMAC would be calculated by projecting DSM costs for the next year, adjusted by the previous year's over- or under-collection, and adding the revenue to be recovered from the performance incentive. The total amount to be recovered would be divided by the projected retail sales ("kWh") for the next year to calculate a per kWh rate, except for demand-billed General Service customers who would pay a per kW rate. The Agreement continues the exemption of qualifying low income customers from the DSMAC charge that was established by this Commission in Decision No. 70961. All customers, except those on low income rates E-3 and E-4 and those on solar rates Solar-1, Solar-2, and SP-1, would pay the DSMAC rate. Interest would be applied only when an over-collected balance results in a refund to customers. The interest rate would continue to be based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 and adjusted annually on the first business day of the calendar year. Interest would no longer be applied to an under-recovered balance.

Q. When would the DSMAC rate be reset?

A. The DSMAC rate would be reset annually by the Commission as part of its consideration of the annual Implementation Plans discussed below. After approval, the rate would become effective with the first billing cycle in March.

Q. What is in the Agreement regarding unrecovered fixed costs?

A. Under the terms of the Agreement, APS will not receive recovery of unrecovered fixed costs as a component of DSM program costs in this rate case. APS could seek such recovery in its next rate case or in other proceedings.

Q. What is in the Agreement regarding Implementation Plans?

A. The Agreement provides for APS to file annual Energy Efficiency Implementation Plans for 2010, 2011, and 2012, with new and/or expanded programs or program elements necessary to meet the energy efficiency goals contained in the Agreement. Each Implementation Plan would include estimates of program savings and costs.

Q. When would the Energy Efficiency Implementation Plans be filed?

A. APS will file the 2010 Implementation Plan by July 15, 2009, and the 2011 and 2012 Implementation Plans by June 1, 2010, and June 1, 2011, respectively.

Q. What will be included in the 2010 Implementation Plan?

A. The 2010 Implementation Plan will include, at a minimum:

a. a customer repayment/financing program element within the non-residential programs for schools, municipalities, and small businesses;

b. a goal for at least 100 schools to receive the installation of DSM measures through APS' programs by December 31, 2010;

c. a review of the low income weatherization program for possible enhancement;

d. a Residential Existing Homes Program, consisting of both a new Home Performance element and the existing HVAC element, with a goal of serving at least 1,000 homes through the Home Performance element by December 31, 2010;

e. a non-residential high performance new construction program element; and

f. a residential high performance new home program element to be filed by June 30, 2009.

Q. Will the DSMAC Plan of Administration need to be revised?

A. Yes. The DSMAC Plan of Administration will need to be revised to incorporate the modifications to the DSMAC that are included in the Agreement.

Q. Was the revised DSMAC Plan of Administration filed with the Agreement?

A. No, APS has filed a revised PSA Plan of Administration on June 29, 2009.

Q. When does Staff expect to complete its review of the revised DSMAC Plan of Administration?

A. Staff expects to complete its review of the revised PSA Plan of Administration after this testimony has been filed and would therefore address it in reply testimony

Renewable Energy

Q. What does the Agreement contain in regard to renewable energy?

A. The Agreement provides for APS to exceed the renewable energy requirements of the Renewable Energy Standard and Tariff ("REST") rules.

Q. What are the REST rules?

A. The Commission adopted the REST rules on November 14, 2006 in Decision No. 69127. After certification by the Office of the Arizona Attorney General, the REST rules went into effect on August 14, 2007. The REST rules require APS and other utilities to derive a portion of the retail energy they sell from renewable electricity technologies.

Q. How much renewable energy does the Agreement propose?

A. The Agreement provides for APS to acquire new renewable energy resources with annual generation or savings of 1,700,000 MWh to be in service by December 31, 2015. These new renewable acquisitions, in combination with existing renewable commitments, are estimated to be approximately 10 percent of APS' retail sales by the end of 2015. In contrast, the REST rules requirement is 5 percent in 2015 and 10 percent in 2020.

Q. What specific renewable items does the Agreement address?

A. The Agreement addresses in-state wind generation, utility-scale photovoltaic generation, transmission, solar energy at schools, and solar energy at governmental institutions.

Q. Please describe the in-state wind generation provision.

A. The Agreement provides for APS to issue a request for proposals ("RFP") for in-state wind generation within 90 days of Commission approval of the Agreement. APS would file a request for Commission approval of one or more of the potential projects within 180 days of issuance of the RFP.

Q. Please describe the utility-scale photovoltaic generation provision.

A. Pursuant to the Agreement, APS would file a plan for a utility-scale generation project for Commission approval within 120 days of Commission approval of the Agreement. The

project would have a construction initiation date not later than 18 months from the filing date. Selection of the project would be the result of a competitive procurement. This photovoltaic project would be in addition to the concentrated solar power projects already under consideration or previously approved by the Commission.

Q. Please describe the Agreement provisions regarding transmission.

A. After transmission projects are prioritized following the Biennial Transmission Assessment report, APS would begin permitting, design, engineering, right of way acquisition, regulatory authorization, and line siting for one or more new transmission lines or upgrades designed to facilitate delivery of renewable resources to the APS system. APS would then construct such transmission lines or upgrades after obtaining permitting and authorizations.

Q. What does the Agreement contain regarding solar energy at schools?

A. Within 120 days of the Commission Order approving the Agreement, APS would file for Commission approval a new program that eliminates up-front customer costs for on-site solar energy (including photovoltaics, solar water heating, and daylighting) at public and charter K-12 schools. The goal would be 50,000 MWh of annual solar energy generation or savings within 36 months of Commission approval of the program.

Q. What does the Agreement contain regarding solar energy at governmental institutions?

A. Within 120 days of the Commission Order approving the Agreement, APS would file for Commission approval a new program that substantially reduces or eliminates up-front customer costs for distributed solar energy (including photovoltaics, solar water heating, and daylighting) at governmental institutions.

Q. What other provisions are in the Renewable Energy section of the Agreement?

A. The Agreement also provides for APS to recover its reasonable and prudent expenses through the Power Supply Adjustor, a renewable energy adjustment mechanism, or the Transmission Cost Adjustor, as appropriate. The expenses would include the carrying costs of any capital investments by APS in renewable energy projects, depreciation expenses, property taxes, and return on both debt and equity at the pre-tax weighted average cost of capital. Because of this provision, APS would not seek to recover Construction Work in Progress related to any of the renewable projects required by the Renewable Energy section of the Agreement. In addition, APS agrees to the renewable energy commitments in the Settlement Agreement regardless of the outcome of any judicial challenge to the REST rules.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on ratemaking, energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst Manager (May 2005-present). Supervise the energy portion of the Telecommunications and Energy Section. Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters.

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-May 2005), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003-2005; Staff Report and testimony on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Arizona Electric Power Cooperative Rate Case (Docket No. E-01773A-04-0528), Arizona Corporation Commission, 2005; testimony on a fuel and purchased power cost adjustor, demand-side management, and rate design.

Trico Electric Cooperative Rate Case (Docket No. E-01461A-04-0607), Arizona Corporation Commission, 2005; testimony on the Environmental Portfolio Standard; demand-side management; special charges; and Rules, Regulations, and Line Extension Policies.

Arizona Public Service Company (Docket Nos. E-01345A-03-0437 and E-01345A-05-0526), Arizona Corporation Commission, 2005; testimony on the Plan of Administration of the Power Supply Adjustor.

Arizona Public Service Company Emergency Rate Case (Docket No. E-01345A-06-0009), Arizona Corporation Commission, 2006; testimony on bill impacts.

Arizona Public Service Company Rate Case (Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827), Arizona Corporation Commission, 2006; testimony on funding for renewable resources, net metering, green pricing tariffs, and a Power Supply Adjustor surcharge.

Tucson Electric Power Company Filing to Amend Decision No. 62103 (Docket No. E-01933A-05-0650), Arizona Corporation Commission, 2007, testimony on demand-side management, time-of-use, direct load control, and renewable energy.

Consideration, Pursuant to A.R.S. § 40-252 to Modify Decision No. 67744 Relating to the Self-Build Option (Docket No. E-01345A-07-0420), Arizona Corporation Commission, 2008, testimony on the self-build option for Arizona Public Service Company.

Sempra Energy Solutions Application for Certificate of Convenience and Necessity (Docket No. E-03964A-06-0168), Arizona Corporation Commission, 2008, testimony on the overall fitness of Sempra Energy Solutions to provide competitive retail electric service in Arizona.

Tucson Electric Power Company rate case (Docket No. E-01933A-07-0402), Arizona Corporation Commission, 2008, testimony in support of the Settlement Agreement regarding renewable energy, demand-side management, Rules and Regulations, partial requirements service tariffs, interruptible tariff, demand response, and bill estimation.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

"Staff Report on Interconnection for the Generic Investigation of Distributed Generation," Arizona Corporation Commission, 2007.

ALL-STATE LEGAL®
EXHIBIT
S-13
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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 RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01345A-08-0172

DIRECT TESTIMONY

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

FRANK W. RADIGAN

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

JULY 01, 2009

TABLE OF CONTENTS

	Page
Introduction	1
Revenue Allocation	1
Rate Design	2
Interruptible Rates	3
Demand Response	4
Other Rate Schedules	6

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 120 Washington Avenue, Albany, New York 12210.

Q. Are you the same Frank Radigan who previously filed testimony in this proceeding?

A. Yes. I previously filed direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the scope of your testimony?

A. I will address the revenue allocation and rate design issues contained in the Settlement Agreement. The Settlement Agreement addresses revenue allocation and rate design in Sections XVII - XXI.

REVENUE ALLOCATION

Q. Please comment on the revenue allocation contained in the Settlement Agreement.

A. The Settlement Agreement at Section XVII 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. Existing low-income schedules, however, shall not receive any base rate increase, as set forth in Paragraph ~~16.1~~ 17.1. The total base rate increase, is $344.7 million which results in a 13.07% increase.

In addition, the base rate increase allocated to the E-32 rate class is differentiated between the four subclasses within the service class. The subclasses are differentiated by customer size, and the revenue allocation to the larger customers is less than the revenue allocation to the smaller classes. The E-32 (400 + kW) subclass will receive an increase that is 2.5% below the average for the group. The next subclass of E-32 (101-400 kW) will receive the group average increase, and the next subclass of E-32 (21-100 kW) will receive an increase that is 1% above the average for the group. The last subclass, E-32 (0-20 kW), will receive an increase that is above the average for the group in order to recover the remaining revenue requirement (approximately 2.8%). This allocation among subclasses reflects of the expected differences in the cost to serve them.

There have been a considerable number of changes in rate classes in this and the Company's last rate case. In my direct testimony, I questioned whether the cost of service study properly captured all the impacts. The allocation in the Settlement Agreement is a reasonable resolution of the various proposals put forth by parties in their testimony.

RATE DESIGN

Q. Could you please comment on the rate design issues in the Settlement Agreement?

A. Yes, the Settlement Agreement at Section XVIII calls for three specific rate design matters. The first addresses the voltage discount for Schedule E-35, the rate schedule that is applicable to APS' largest customers. Under the terms of the Settlement Agreement (paragraph 18.1), the voltage discount for customers taking service at transmission voltage level will be equal to the current discount adjusted by the overall E-35 percentage increase. The current discount is a 28% discount from the demand rate assessed to primary service customers.

The second matter addresses APS' proposal for third party transmission charges for Rate Classes E-34 and E-35. In its original filing, the Company had proposed the addition of a provision to the E-34 and E-35 rate schedules to require customers 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. (Delizio PFT, page 33). Freeport-McMoRan & Gold, Inc. and Arizonans for Electric Choice and Competition opposed the change in direct testimony, claiming that it was both unusual in a retail rate tariff and that it could lead to double recovery. Paragraph 18.2 specifically rejects this APS proposal.

The third rate design matter addressed in the Settlement Agreement is the rate increase for the Schedules E-34, E-35, and E-32 (401+ kW). In the Company's original filing, it had asked that these charges be increased to better reflect the cost of service. Paragraph 18.3 of the Settlement Agreement will implement the rate increase for Rates E-34, E-35, and E-32 (401+ kW) by adopting APS' proposed changes in the customer charges with an equal percentage increase in demand and energy charges.

The three rate design matters addressed in the Settlement are limited and specific to a small number of customers. They are also reasonable as they either maintain the existing rate design discounts between voltage levels or move toward the cost of service.

INTERRUPTIBLE RATES

Q. Could you please comment on the proposed interruptible rate schedules?

A. Yes, Section XIX of the Settlement Agreement states that, within 180 days of the Commission's approval of the Settlement Agreement, APS, after consultation with Staff and interested stakeholders, will file for Commission approval an interruptible rate for customers with loads over three megawatts. The interruptible rate will provide a credit to

participating customers based on avoided capacity costs and the customer's commitment to interrupt. While still in the development stage, the interruptible rate may consist of two rate elements for a short-term customer (e.g., one year) and a long-term customer (e.g., up to five-years).

Demand reduction programs are a useful tool in managing peak demand, and the introduction of such an interruptible rate could greatly assist in this effort. Allowing both short-term and long-term commitment periods is particularly interesting. In my experience, many utilities are reluctant to count on interruptible load in the long-term as they are not sure that it will be available as a resource. As such, the longer time period could further assist the utility in managing its peak demand.

DEMAND RESPONSE

Q. Could you please comment on the demand response proposals contained in the Settlement Agreement?

A. Yes, Section XX of the Settlement Agreement contains several offerings which could influence the timing of customer energy usage. Paragraph 20.2 commits APS to provide prospective customers with clear and complete information about all the demand side management options. It also provides that APS shall market its demand response programs with its energy efficiency programs. There are three specific demand response programs.

First, paragraph 20.3 of the Settlement Agreement states that a new super peak time-of-use rate for residential customers should be adopted. Super peak time-of-use rates have a short but high cost usage charge to encourage customers to avoid using power during the highest usage periods. In return, they receive a discount for usage in the off-peak period.

I supported the super peak time-of-use rate in my original testimony in this proceeding. This is yet another means by which to alleviate load during the critical peak period. The Company's existing TOU rate options have been effective in encouraging customers to move load to off-peak periods. The Super Peak TOU option, which concentrates the financial incentive to a select few hours during the peak months, could prove an even more effective tool.

The second demand response program in the Settlement Agreement is addressed in Paragraph 20.4. It calls for a critical peak pricing rate, GPP-GS, to be implemented on a pilot basis. The Agreement provides that the Company will make a good faith effort to attain participation of at least 200 customers in this pilot program. This is another Company proposal that I supported in my original testimony as it is a positive step to control peak load, it is targeted to customers that can most likely shed load; it provides an adequate discount to encourage participation, and it is limited in scope so that it can be controlled, evaluated, and improved before it is offered to all customers.

The third and last demand response program addressed in the Settlement Agreement is discussed in Paragraph 20.5. It calls for APS to implement a residential critical peak pricing pilot program but also to make a good faith effort to attain participation of at least 300 customers. As stated in the Settlement Agreement, this program will be designed to provide participating customers with strong, clear price signals that are narrowly focused on a limited number of specific hours of each year. Again, my examination of the Company's current time-of-use options shows that its customers react positively to price signals, this program could therefore be another valuable tool available to the Company.

Another positive aspect of the Settlement Agreement appears in Paragraph 20.6, where APS commits to prepare a study on the impact of its super peak and critical peak pricing programs on generation use, air emissions, and energy use. The study shall identify methods to better integrate demand response programs and energy efficiency programs. This is an important provision. Too many times programs are funded, but then uncoordinated with other efforts, and synergies are lost. Moreover, the commitment to learn and improve from pilot programs is important since I have too often seen such programs become orphaned after the initial effort.

OTHER RATE SCHEDULES

Q. Could you please comment on the other rate schedule matters?

A. The Settlement Agreement at Section XXI states, that within 90 days of approval of the Settlement Agreement, the Company will file a new optional TOU rate applicable to schools, K-12, which will be designed to provide daily and seasonal price signals to encourage load reductions during peak periods. The Arizona School Boards Association and the Arizona Association of School Business Officials sponsored testimony on the need for such a rate, and noted that Arizona School Districts will be facing major financial issues over the next several years. (Pre-Filed Testimony of Chuck Essigs, page 2). While many of the rate design matters in the Settlement Agreement are innovative and promising, this provision may well be the most interesting. This provision is a means to address the financial issues that school districts face. One must also recognize, that energy conservation results primarily from a knowledge of consumption and pricing however. Introducing these concepts into schools may be the best way to educate students, teachers, and parents of the benefits of energy conservation.

Q. Does this conclude your testimony?

A. Yes, it does.

ALL-STATE LEGAL®
EXHIBIT
S-14
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

SUPPORTING THE SETTLEMENT AGREEMENT

OF

ELIJAH O. ABINAH

ASSISTANT DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 13, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

PURPOSE 1

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My Reply Testimony adopts the testimony filed in by Mr. Ernest Johnson on July 1, 2009, on behalf of the Utilities Division, in support of the Settlement Agreement. I also explain that parties opposing the settlement have raised an issue concerning Schedule 3 that is strictly a policy issue of whether existing customers should pay for growth or should new customers (the cost causers) pay for growth. Staff supports the Settlement Agreement as filed without modifications.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Elijah O. Abinah. My business address is 1200 West Washington Street, Phoenix, Arizona, 85007.

Q. Where are you employed and in what capacity?

A. I am employed by the Utilities Division ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission") as the Assistant Director.

Q. Did you previously testify in this Docket?

A. No. But I intend to adopt the testimony filed by Mr. Ernest Johnson on July 1, 2009, on behalf of the Utilities Division, in support of the Settlement Agreement.

Q. Are you familiar with the Settlement Agreement filed on June 12, 2009 by the parties?

A. Yes.

Q. Were you involved in the Settlement process?

A. Yes.

PURPOSE

Q. What is the purpose of your Reply Testimony?

A. As stated above, the purpose of my testimony is to adopt Mr. Johnson's testimony that was filed on July 1, 2009, and to further discuss the issue of line extension (Schedule 3), free footage.

Q. Is Staff proposing any changes to the Agreement or Staff's testimony?

A. No. Staff continues to support the Agreement as proposed. Staff believes the Agreement as proposed is in the public interest.

Q. Have you reviewed all the letters filed in the docket in relation to Schedule 3 (line extension)?

A. Yes.

Q. Can you please briefly describe Section X of the Settlement Agreement.

A. Yes.

Section X contains seven paragraphs. Paragraph 10.1 provides that APS will record Schedule 3 receipts as revenue for a limited time, specified therein. Paragraph 10.2 states APS' estimates of the amount of Schedule 3 revenues for each year, 2010 through 2012. Paragraph 10.3 indicates that the Agreement maintains the Commission's current policy regarding customer payments for line extensions. The Commission's current policy is for no free footage allowance. The focus of the parties opposing the Agreement appears to be solely on Paragraph 10.3, and specifically they would like to have a free footage allowance reinstated. Paragraph 10.3 also provides that, should the Commission decide to modify Schedule 3 in this proceeding (such as to provide for some reinstatement of a free footage allowance), the Signatories contemplate that offsetting revenue changes should be ordered that would make such modifications revenue neutral to the provisions of this Agreement. Paragraphs 10.5 and 10.6 provide that the Impact Fee and System Facilities Charge proposed by APS are withdrawn. Paragraph 10.7 provides for APS to make certain revisions to Schedule 3 to improve it in response to customer complaints.

Q. Does Staff believe that an allowance for free footage is largely a policy issue?

A. Yes. First, let me make it clear that Staff supports the Settlement Agreement as proposed. However, if the Commission were inclined to revisit the issues regarding free footage, Staff believes that the relevant issue is one of policy, not technical in nature.

Q. Can you please explain.

A. The issue of some sort of free footage allowance comes down to who pays for what. Should the existing customers pay for extensions, or should the new customers (the cost causers) pay for growth?

Q. Based on the testimony filed by individuals in opposition to the Settlement Agreement, and various letters filed in this docket, is Staff recommending a different treatment of Schedule 3 receipts?

A. No. Staff supports the Settlement Agreement as proposed. The policy embodied therein continues the Commission's existing line extension policy, which eliminates free footage for certain line extensions. However, in order to assist the Commission, should it be inclined to revisit this issue, Staff believes that the Commission may consider the scenarios presented in Mr. Smith's testimony.

Q. Have you reviewed the letter docketed by Chairman Mayes on August 5, 2009?

A. Yes, Staff reviewed the letter. Staff intends to respond to the Chairman's letter at the hearing, where applicable.

Q. Did Staff perform any analysis and/or surveys of other state jurisdictions on the treatment of line extensions?

A. Yes. Staff researched various Commission rules and regulations in other states, and various electric service providers' tariffs. Staff was able to compile information on how other jurisdictions address issues similar to that presented by APS' Schedule 3 (line extensions). This survey is attached to my testimony.

Q. Does this conclude your Reply Testimony?

A. Yes.

LINE EXTENSION ALLOWANCE NATIONWIDE SUMMARY
August 10, 2009

1) **Alabama**

Alabama Power - Each utility shall have on file with the Commission an acceptable policy for extensions of its service where such extensions are in excess of the regular rates for service and for which the customer shall be required to pay all or part of the cost. Such policies shall be kept current by the utilities and shall be subject to review by the Commission. Such policies shall be the basis upon which a customer's cost for such extensions will be paid.

2) **Alaska** - Free allowance defined in each utility's tariff; reviewed tariffs of three companies, and they allowed new service credits per lot of $1,000, $3,000, and $3,100.

3) **Arkansas**

Entergy - The Extension Allowance for permanent single residential applications is $1000. The Extension Allowance for a residential application in a planned development is $250. Residential meters used by the Company for billing purposes are provided at no cost to the Applicant. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

4) **California** - In order to foster competition, the Commission decided to delete the requirement for free footage for new line extensions. Each utility establishes its extension allowance, i.e., PG&E shows that a new customer receives an allowance towards his installation cost. The allowance is calculated as the Net (anticipated) Distribution Component Revenue for a year divided by the Cost of the Service Factor (Rate of Return, Maintenance, overhead and other utility costs). The customer gets a quote from the utility and then can shop for an approved competing contractor. For residential line extensions, a fixed allowance is provided based on average residential consumption. The allowance is first applied towards the service extension (line from transformer to service panel) and the rest to the primary distribution line extension, if required.

5) **Colorado**

Xcel (Public Service Corporation Colorado) - $720 allowance.

6) **Connecticut**

United Illuminating - Additional Customer Requirements: (b) The Customer shall furnish, free of cost to the Company, upon its Premises the necessary space and provide, in conformity with the Company's specifications and subject to its approval, suitable foundations, supports, housing, equipment replacement access, equipment ventilation, grounding, wiring, conduit, and fittings for any transformers, switching arrangements, meters, and other apparatus required in connection with the supply of electricity. (c) Overhead Wires: One span of overhead wires will be installed at the Company's expense between the overhead

wires in the street and the Customer's service entrance wires. (d) Additional Poles and Wires: Upon the Customer's request, and subject to Company approval, additional poles and wires will be furnished and installed on private property, in conformance with Company specifications, additional poles and wires must be paid for by the Customer. The Company will assume ownership and maintenance of such additional poles and service wires on private property if given written permission by the owner of the property.

7) **Delaware**

Delmarva Power - If the service exceeds 300 feet, the Applicant shall pay the Company the additional installed cost for the length greater than 300 feet, based on the average installed cost per foot for residential services installed during the preceding calendar year. Any such payments shall not be waived or refunded.

8) **Florida**

Florida Power & Light – (a) The CIAC for new or upgraded overhead facilities (CIACOH) shall be calculated as follows:
CIACOH = Total estimated work order job cost of installing the facilities - Four years expected incremental base energy revenue - Four years expected incremental base demand revenue, if applicable.

9) **Georgia**

Georgia Power - The Company shall not be required to spend more than 3.5 times the estimated annual base rate revenue for providing residential service. Where the cost to serve does exceed this maximum expenditure, a payment in the amount of such excess will be obtained.

10) **Hawaii**

Hawaii Electric Company - The power company will, at its expense, furnish and install a single span of service conductors from its pole or other aerial support, to the customer's approved point of attachment. The utility will connect to the service entrance conductors, provided such support is of a type acceptable to the utility and complies with all applicable ordinances and requirements.

11) **Idaho** - No laws or rules of general applicability regarding electric line extensions. Each utility has specific provisions in their tariffs. As a matter of policy, the Commission has been moving away from the free footage concept and towards giving customers an "allowance" for terminal facilities, which is credited against the total line extension cost.

12) **Illinois** - First 250 feet free.

13) **Indiana**

Indianapolis Power and Light - Standard Term Contracts - An extension of the Company's service facilities, including changes from single phase to three phase, will be made at the Company's expense if, in the judgment of the Company, the Revenue as computed by the Company exceeds the Cost of Installation as

computed by the Company. If the Cost of Installation above exceeds the Revenue above, the Developer must pay the difference to the Company.

Short Term Contracts - There shall be an estimate made of the Actual Cost of the line extension. The Developer shall deposit the amount of the estimated Actual Cost with the Company prior to the commencement of the work.

14) **Iowa** - First 50 feet free.

15) **Kansas** - First 75 feet free.

16) **Kentucky** - Defined in each utility's tariff; 800 feet free footage allowance.

17) **Louisiana**

Entergy Louisiana – Company funded line extensions and/or additions of not more than 36 times the minimum monthly revenue that customer to be served will satisfactorily guarantee for a minimum period of 36 months. If customer does not make commitment, then the minimum monthly revenue guarantee sum must be: 1/36 of Company's portion of cost of extension/addition and 1/72 of customer's contribution to cost of extension/addition.

18) **Maine** - No part of a private line extension is constructed by an electric utility without charge. The largest utility does provide a subsidy of $2,800 or the actual cost of the line, whichever is less, to qualifying low income customers.

19) **Maryland** - Generally, customers must pay the full amount of extensions on their own property. System extensions that are constructed in a manner that improves the system or could serve other customers are provided with a subsidy and recovered in base rates. There is a $1 per foot maximum charge for overhead extensions made along a public street.

Allegheny Power – First 1500 feet free.

20) **Massachusetts**

Western Massachusetts Electric Co ("WMECO") line extension policy states the following:

In consideration of anticipated average revenue, WMECO will extend one pole and one span of overhead construction on a public way, at no cost to the customer. WMECO will also provide one span of overhead secondary service (limited to 400 ampere service entrance capacity for non-residential customers) on private property, at no charge to the customer. For all construction beyond the allowances specified above, the customer will be required to contribute the excess costs.

21) **Michigan** - Each company has a line extension program and most allow free footage 200 to 300 feet.

22) Minnesota - There is not a specific statute or rule in Minnesota regarding electric line extensions. Each utility does have Commission-approved tariffs covering line extensions.

> ***Northern States Power Company, d/b/a Xcel Energy***, is the largest electric utility in Minnesota. The basic "free" footage for standard residential installations is 100 feet. The current excess footage charge is $6.85 per circuit foot. For commercial/industrial customers, there is no explicit "free" footage, rather the cost of extending service is based on a formula which includes anticipated revenues.
>
> ***Minnesota Power & Light Company*** has a different approach, which is a set dollar amount cap on the cost of the service extension, rather than a footage allowance. Minnesota Power's tariff states the following:
>
> BASIS FOR MAKING EXTENSIONS FOR PERMANENT SERVICE WHERE EXTENSION COSTS ARE $30,000 OR LESS
> If the Extension Cost does not exceed $850 and Company's standard type construction is used in making the extension, Customer shall not be required to make payment to Company for the Extension Cost.
> If the Extension Cost exceeds $850, and is for single phase service, customer must pay Company in advance a Contribution for the Extension Cost in excess of $850.
> If the Extension cost exceeds $850 and is for non-single phase service, Customer has the following options:
> 1. Pay Company in advance a Contribution for the Extension Cost in excess of $850, or
> 2. No advance contribution for extension costs will be required, if the customer enters into a five year Electric Service Agreement where the Company's costs relating to the entire extension are equal to or less than three times the Customers guaranteed annual revenues, or
> 3. If the Customer enters into a five year Electric Service Agreement where the Company's costs relating to the entire extension are greater than three times the Customer's guaranteed annual revenues, the Customer will be required to pay the Company in advance a Contribution for the balance of the Extension Cost not supported by guaranteed annual revenues.

23) Mississippi

Entergy Mississippi, Inc. – First 600 feet free.

24) Missouri - Each of the four regulated electric utilities has its own free footage allowance; two allow for 1,000 free feet, one allows 1,320 free feet, and one allows 100 free feet.

25) Montana – 150 feet free overhead and 100 feet free underground.

26) Nebraska - All electric utilities (171) are publicly owned and not regulated at the state level with respect to services and rates. Jurisdiction is limited to the safety of construction, operation and maintenance of transmission lines outside municipal city limits. No state rules or tariffs establishing line extension guidelines for the electric industry.

27) Nevada - No free footage allowance for electric line extensions. Instead utility calculates how much electricity the incoming customer would be using the first year of service and the dollar value of that service is deducted from the cost, i.e., if the line extension would cost $1,000 and the customer would use at least that much electricity the first year, there would be no cost to customer. Conversely, if the line extension would cost $1,500 and the customer is projected to use $1,000 the first year, the customer would pay $500.

28) New Hampshire

Public Service Company of New Hampshire – First 300 feet free; 300 to 5,280 feet $0.14 per foot, per month with 60 month contract.

29) New Jersey - According to NJ Administrative Code ("N.J.A.C") §14:3-8-A regulated entity shall not pay for or financially support an extension or portion thereof described at (a) above except pursuant to an exemption under N.J.A.C. 14:3-8.8. The Board shall not consider the cost of the extension when determining the regulated entity's rates under N.J.S.A. 48:2-21.

None of the four electric companies (Atlantic City Electric Company, Jersey Central Power and Light Company, Public Service Electric and Gas Company, and Rockland Electric Company) have free allowance policies.

30) New Mexico - No rules, laws, or tariffs implemented allowing a particular footage allowance by an electric utility at no charge to customer.

31) New York – First 500 feet free.

32) North Carolina - ***Commission Rule R8-24. Extensions.***
Each utility shall adopt rules, subject to the approval of the Commission, under which it will, upon written request for service by a prospective consumer or a group of prospective consumers, located in the same neighborhood, make the extension necessary to give service and furnish service connection or connections.

Duke-Energy has the following in its tariff: Residences which are to be permanent customer locations on a residential rate schedule of the Company will be served from underground facilities as shown below -

New Service Installations Located in New Developments:

1. Service to new residences on lots averaging an acre (43,560 square feet), or less. No Charge.

2. Service to new residences on lots averaging more than one acre. No charge except for cost difference of new primary facilities exceeding 300 feet per lot.

New Service Installations Not Located in New Developments:

1. Service to new residences requiring new underground secondary voltage facilities from an above-ground distribution line on, or adjacent to, the lot on which the residence is located. No Charge
2. Service to new residences requiring new underground primary and secondary voltage facilities. No charge except for cost difference of new primary facilities exceeding 300 feet.

33) **North Dakota** - The North Dakota Administrative Code ("N.D.A.C") § 69-09-02-07 specifies the following:

1. It shall be the obligation of each utility to make reasonable extensions of its lines and services to new customers within any area in which it is authorized to serve.
2. Each utility shall file with the commission its rules for extending service to new customers, and shall file any changes in the rules which may be made from time to time.
3. If the utility does not consider that an extension within its service area is justified, the commission, upon request of one or more prospective customers to be served by the extension, may set the matter for public hearing to determine if the extension should be made, and the terms and conditions thereof.

Line extension/free allowance policies are specified in each utility's tariff. Only investor-owned utilities are regulated by Public Service Commission

Montana-Dakota Utilities Co. - A permanent extension may be constructed without a contribution if the estimated project construction cost is equal to or less than two times the estimated annual revenue (2 to 1 ratio). If the estimated project construction cost is greater than two times the estimated annual revenue, the extension will be made only with a contribution, which may be refundable.

Northern States Power Company - First 100 feet free allowance.

Otter Tail Power Company -The Company will, at its own expense, extend its facilities for supplying electric service when the anticipated revenue from the sale of additional service justifies the expenditure. If it appears to the Company that the expenditure may not be justified, the Company may require the customer to sign a contract guaranteeing a certain minimum amount of revenue over the first three years use of electric service, or such other initial period of service as may be determined by the Company, and to make an advance payment, as determined by the Company, to guarantee payment of this minimum amount of revenue. If the customer uses the specified minimum of electric service by the end of the said initial period of service, the advance will be refunded to him. However, if the customer uses less than the minimum, the amount of the deficiency will be billed to the customer, or will be deducted from the deposit, and the balance of the deposit, if any, will be refunded to the customer.

34) **Ohio** - New rules were approved in May of 2009, and they become effective August 24, 2009. The rules do not allow for a particular footage, but a dollar amount of up to $5,000 to be paid by the utility for residential service (single family homes), and up to $2,500 per unit for residential multifamily (two or more units).

35) **Oklahoma** – First 300 feet free.

36) **Oregon**

PacificCorp – Residential Allowance of $750.

37) **Pennsylvania**

West Penn Power Co. tariff states the following:

Line extension provided without financing or guarantee plans not exceeding 1,000 feet; with not more than 400 feet on private property unless there is documented potential for additional Customers.

Citizens Electric Co. of Lewisburg tariff contains the following:

1. The Company requires a minimum revenue guarantee for installation of any length of single phase line extension in excess of 2,500 feet along the normal route of development of the distribution system, and for installation of all multi-phase line extensions. The guarantee period is 5 years or less.
2. Minimum revenue guarantee for single phase extensions are based only on the contractor costs, if any, and the direct labor costs and direct material costs attributable to construction of the line extension beyond the maximum extension distance. Guarantees for multi-phase extensions are based on fully allocated costs, and are credited with the equivalent single phase length allowance for up to 2,500 feet of new pole line along the normal route of development of the distribution system.
3. Any length of line extension on, or through, restricted lands is excluded from the line extension allowance and is subject to a line extension guarantee.
4. The excess cost of construction other than would normally be required for installation of the line extension, is paid by the Customer prior to installation.

38) **Rhode Island** - The Rhode Island Administrative Code ("R.I.A.C") does not include regulations regarding line extensions. Each electric company has its own specific rules and regulations for line extensions. National Grid (overhead is the standard).

-Residents

The company provides up to two poles and two spans of overhead distribution line needed to serve the customer plus a service drop (that does not require a carrier pole) to the customer's home free of charge. If more than two poles and two spans of overhead distribution line are required to serve the customer's home, the customer will pay an "Overhead Installation Charge" The OIC will be equal to the number of feet of distribution line (beyond two poles and spans) required to serve the customer's home, multiplied by the "Overhead Cost Per Foot".

-Residential Developments

The company will provide 150 feet of overhead distribution line, not including the secondary service drop, per each "house lot" free of charge. If the number of

centerline feet of overhead distribution line required to serve the development ("Required Line Distance") is greater than the "Allowed Distance" of 150 feet per "house lot", then there will be a charge to the Developer for the overhead line extension for the additional feet Overhead Installation Charge. The additional charge shall be paid by the Developer in advance of the Company's construction. The OIC will be equal to the "Overhead Cost Per Foot" times the number of feet in excess of the "Allowed Distance" of 150 feet per House Lot (plus applicable tax contribution factor).

-Commercial, Industrial, and Existing Residential Customers

If the New Facilities being requested by the Customer consists of an overhead, single phase, secondary voltage distribution line extension that does not exceed two poles and two spans of line, the Company will provide the poles and spans of line needed to serve the New Facilities plus a service drop (that does not require a carrier pole) free of charge to the Customer. Otherwise, the costs of all poles and spans of line determined by the Company as needed to serve the New Facilities will be included in the cost.

39) **South Carolina** - Each electrical utility shall be obligated to comply with all requests for service in accordance with its schedules of rates and service rules and regulations on file with the commission and the ORS within areas assigned to it by the commission and within three-hundred feet of its lines as they existed on the date of assignment.

Duke Energy's reads, "The Company will extend its facilities and change the point of delivery only when the investment required is warranted by the anticipated revenue and when the extension is permissible and feasible."

40) **South Dakota**

Xcel Energy Inc. - First 100 feet free on private property and $6.85 per circuit foot beyond 100 feet.

41) **Tennessee** - Defined in each utility's tariff; 800 feet free footage allowance.

42) **Texas**

Oncor – First 300 feet free.

Centerpoint – First 2,000 feet free.

43) **Utah**

PacificCorp - The Extension Allowance for permanent single residential applications is $1100. The Extension Allowance for a residential application in a planned development where secondary voltage service is available at the lot line is $350. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

44) **Vermont**

Central Vermont Public Service - the Company will place and construct primary and secondary service extensions. The total cost of providing the service extension,

including any tax assessments and recognizing any telephone company participation, less the credit for the service drop, if applicable, shall be paid by the party requesting the service extension.

Green Mountain Power - shall require full reimbursement for all of the costs of all line extensions installed at the customer's request, minus a service drop credit for each new single family residence or individual dwelling unit. The customer shall be charged for the line extension based on the average cost per foot of each construction element used in the line extension. The service drop shall include a 100 foot overhead power line(s) from the initial customer connection with GMP's secondary facilities to the Delivery Point.

45) Virginia - Each electric distribution utility (or electric cooperative) files a line extension policy as part of its tariffs (terms and conditions of service.) The general policy of the Commission in accepting such tariffs, and any proposed revisions that may be offered in a rate case, is a "reasonable and customary" standard. There is no set footage amount, it varies by company. The distribution company would bare the cost of such lines. However, if a line extension (or alteration) is required to serve and requested by a customer that is determined to go beyond what is considered reasonable and customary, then the customer would be responsible for the cost difference in order to accommodate service to that customer.

Virginia Electric & Power dba Dominion Virginia Power - that the Company will make single-phase electric line extensions to residential customers, three-phase residential line extensions, nonresidential line extensions, and line extensions to any appurtenance(s) of residential dwelling units in accordance with the following. The Customer will pay the amount, if any, by which the cost of the line extension exceeds four times the continuing annual revenue--less fuel charge revenue-- that can reasonably be expected from the extension. If a proposed electric line extension is of such great length or high cost, or if in the Company's opinion, the anticipated Electric Delivery Service revenue from such line extension is insufficient or temporary, or if the Customer or Customers to be supplied are unable to establish a credit standing satisfactory to the Company, the Company reserves the right to determine finally the advisability of making such line extension. Whenever it is determined that a line extension on private property to serve one Customer will be built by the Customer such line extension:

1. shall start within 100 feet of the Company's line,
2. shall be constructed in compliance with the Company's standards and be approved by the Company,
3. shall be maintained by the Customer at all times in a manner satisfactory to the Company, and
4. the Customer shall assume the liability for the maintenance and operation of the line. If the line owned by the Customer is not operated and maintained in a manner satisfactory to the Company, or, in the Company's opinion, may interfere with or be detrimental to its facilities or to the provision of Electric Service by the Company to any other Customer, then the Company may

discontinue Electric Service as provided in Section XVI--Discontinuance of Electric Service.

Northern Virginia Electric Cooperative - will extend its overhead or underground distribution lines to any permanent residential or commercial Customers who request service. Extensions shall be single phase unless the Cooperative elects to build poly-phase lines. NOVEC will provide, own, and maintain the line extension including poles, fixtures, transformers, wires, and appurtenances required to extend its overhead system so that the Cooperative's service wires can be attached to the Customer's building or other delivery point. Beyond this point of attachment, all additional wiring and all other facilities on the Customer's premises shall be provided by and remain the property of the Customer. The Cooperative will furnish adequate single phase service to all permanent residential and commercial connections, occupied on a full-time, year-round basis, within the territory allocated to NOVEC by the Commission under the Utilities Facilities Act of 1950. No line extension charge will be made for permanent single phase service except as required for underground service extensions.

46) Washington

PacificCorp - Extension Allowances: The Extension Allowance for Residential applications is $1050. The Extension Allowance for Residential applications in a Planned Development is $250.

47) West Virginia - Each utility's line extension rules rein their respective tariffs. Both of the two major electric utilities provide for residential extensions up to 1,000 feet with no customer contribution. Extensions beyond 1,000 feet require a customer contribution.

48) Wisconsin

Wis. Adm. Code Ch. PSC 113 addresses electric service extensions. It provides for embedded cost credits for customers requesting new service extensions that are somewhat comparable to the free footage concept.

PSC 113.1006 Embedded cost allowances. The average embedded cost of existing facilities shall be determined annually on a customer classification basis as follows:

1. ENERGY ONLY CUSTOMERS. For customer classifications billed on an energy usage only basis, the embedded cost of the distribution facilities allocated to those classifications shall be divided by the number of customers in the classification to specify an average embedded cost allowance per customer. The utility may create subclassifications of energy-only commercial classification based on customer service entrance capacity or other electrical loan criteria to specify average embedded cost allowances.
2. DEMAND AND ENERGY CUSTOMERS. For customer classifications billed on a demand and energy usage basis, the embedded cost for distribution facilities allocated to those classifications shall be divided by the total billed demand of those customers to specify an average embedded cost allowance per kilowatt of demand.

Wisconsin Public Service Corporation - For each permanent year-round dwelling, the Company will provide a single-phase line extension, excluding service drop, at no additional charge for a distance of 600 feet of which no more than 200 feet is a lateral extension on the customer's private property. For each permanent seasonal-type dwelling, the company will provide at no extra charge a 200-foot extension from a main line distribution feeder. During the five (5) year period immediately following the date of payment, the company will make refunds of the charges paid for a financed extension. The amount of any such refund shall be $500 for each permanent electric service subsequently connected directly to the facilities financed by the customer. Directly connected customers are those which do not require the construction of more than 300 feet of lateral primary distribution line. Such refunds will be made only to the original customer if still receiving service at the same location and will not include any amount of contribution in aid of construction for underground service made under the provisions of the company's underground service policy as set forth in this section. The total refund shall not exceed the refundable portion of the contribution.

49) Wyoming

PacificCorp - The Extension: Allowance for permanent single residential applications is $1000. The Extension Allowance for a residential application in a planned development is $250. Residential meters used by the Company for billing purposes are provided at no cost to the Applicant. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

ALL-STATE LEGAL®
EXHIBIT
S-15
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

REPLY TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

AUGUST 13, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 1

TREATMENT OF SCHEDULE 3 2

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My Reply Testimony in support of the Settlement addresses accounting and ratemaking issues related to Schedule 3 as provided for in the Settlement Agreement. The Settlement Agreement changes the treatment for Schedule 3 receipts to account for them as revenue rather than Contributions in Aid of Construction ("CIAC").

Several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, have filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

In the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities, including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these electric utilities. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy regarding payments for line extensions.

The testimony filed by the parties in opposition to the Settlement does not contest or object to the treatment of accounting for Schedule 3 receipts as revenue. Their recommendation to reinstate a free footage allowance for APS would, however, directly impact the amounts that APS has projected it would receive under Schedule 3 as revenue.

The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document. Specifically, Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding receipts for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the amount of revenue that APS has projected for revenue from Schedule 3. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." Consequently, under this provision of the Settlement Agreement, reinstituting a free footage allowance would mean a higher rate increase for APS' existing customers.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled Direct Testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding, and testimony in support of the Settlement Agreement that was filed on July 1, 2009?

A. Yes.

Q. What is the purpose of your Reply Testimony in support of the Settlement?

A. The purpose of my Reply Testimony in support of the Settlement is to address how the Settlement Agreement provides for the accounting and ratemaking treatment of line extensions in response to testimony filed by various individuals on or about July 22, 2009 in opposition to the Settlement.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your Reply Testimony?

A. My Reply Testimony addresses the accounting and ratemaking aspects of the Treatment of Schedule 3 provisions of the Settlement Agreement.

TREATMENT OF SCHEDULE 3

Q. Please briefly summarize your understanding of the main concern identified in the testimony that was filed in opposition to the Settlement Agreement.

A. On or about July 22, 2009, several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

Q. Has the elimination of a free footage allowance for line extensions been an issue previously in other cases before the Commission?

A. Yes. It was an issue in the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these utilities. Consequently, the elimination of the free footage allowance for APS line extensions is not a new issue in this case.

Q. Arizonans for Fair Power Policy propose that the Commission change its current policy of no free footage allowance for line extensions. Does the Settlement Agreement maintain the Commission's current policy regarding line extensions?

A. Yes. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy of no free footage allowance for line extensions.

Q. Does the Settlement Agreement result in a change to the Commission's current policy of no free footage allowance for line extensions.

A. No.

Q. Do the settling parties propose a change to the accounting treatment of receipts under Schedule 3?

A. Yes. The settling parties are proposing to treat the Schedule 3 receipts as revenue instead of CIAC.

Q. How significant is Section X to the Settlement Agreement?

A. Section X mitigated the need for a higher rate increase. The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document.

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in the Settlement Agreement at paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Are the settling parties proposing any other changes to Schedule 3 other than the accounting treatment of the Schedule 3 receipts?

A. Yes. The Settlement Agreement proposes some important changes to the terms and conditions contained in the Schedule 3 tariff.

Q. Do the parties that are opposing the Settlement Agreement appear to object to the accounting by APS of Schedule 3 receipts as revenue, as provided for in paragraph 10.1?

A. No. Their concern focused to be focused on the restoration of a free footage allowance for APS' line extensions. They do not appear to object to the accounting treatment provided for Schedule 3 receipts in paragraph 10.1 of the Settlement Agreement.

Q. Would the recommendations of parties that are opposing the Settlement Agreement affect the amount of revenue that APS has projected for Schedule 3 receipts?

A. Yes. While the testimony filed by the parties in opposition to the Settlement does not appear to contest or object to the treatment of APS accounting for Schedule 3 receipts as revenue, their recommendation to reinstate a free footage allowance for APS would directly impact the amounts that APS has projected it would receive under Schedule 3. All other things being equal, if a free footage allowance were reinstated for APS, the amount of Schedule 3 receipts to APS would be lower, and the amount of rate increase to existing customers would be higher.

Q. How could the recommendations of parties that are opposing the Settlement Agreement result in a larger rate increase to existing APS customers?

A. The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding payments for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the Settlement Agreement. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." In other words, if Schedule 3 receipts (which APS would be accounting for as revenue) decrease, then another source of revenue, specifically an additional base rate increase, would need to occur in order for the change to be "revenue neutral." Consequently, under this provision, reinstituting a free footage allowance would mean a higher base rate increase for APS' existing customers.

Q. Do you have some estimates of how a reinstatement of a free footage allowance for APS' line extensions could affect the amount of rate increase provided for in the Settlement Agreement?

A. Yes. I should caution that these amounts were provided by APS in the Company's responsive letter to Chairman Mayes dated June 25, 2009, and are estimates. Nevertheless, such estimates appear to be consistent with the figures that were provided by APS and discussed by the Signatories to the Settlement Agreement.

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 by customer requesting the line extension if over $25,000.	$ 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	$ 28,000	$ 33,000	$ 47,000
100 ft. – up to $5,000	$ 173,000	$ 198,000	$ 289,000
500 ft. – up to $10,000	$ 2,274,000	$ 2,614,000	$ 3,816,000
750 ft. – up to $10,000	$ 2,660,000	$ 3,050,000	$ 4,460,000
Scenario 3 – Free footage approach subject to an investment cap.			
50 ft. but not more than $5,000	$ 63,000	$ 71,000	$ 101,000
100 ft. but not more than $5,000	$ 334,000	$ 377,000	$ 540,000
500 ft. but not more than $10,000	$ 2,350,000	$ 2,700,000	$ 3,936,000
750 ft. but not more than $10,000	$ 5,120,000	$ 5,880,000	$ 8,590,000
Scenario 4 - $5,000 equipment allowance.	$ 3,700,000	$ 4,090,000	$ 5,740,000

Q. What would be the impact on the Settlement Agreement if a different scenario was adopted?

A. If a different line extension scenario were to be adopted, the above table also shows the amount of estimated additional revenue increases that would be required pursuant to paragraph 10.3 of the Settlement Agreement which provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral."

Q. In terms of a change to the free footage allowance, would the recommendations of parties that are opposing the Settlement Agreement result in APS' tariff for line extensions being inconsistent with the other large electric utilities, including TEP and UNS Electric, that are regulated by this Commission?

A. Yes. One thing that the Commission may want to consider is that, if a free footage allowance were to be reinstated at this time for APS, this would result in APS' line extension provision being different in that respect from the line extension tariffs of TEP and UNS Electric where free footage allowances have been eliminated by the Commission.

Q. Does the Settlement Agreement result in APS' tariff for line extensions forever being "set in stone"?

A. No. The Settlement Agreement at Section II-A provides for a rate case filing plan, and Section X, paragraph 10.4, which specifically addresses Schedule 3, provides that: "Nothing in this Section of the Agreement is intended to prevent any Signatory from proposing a different treatment for Schedule 3 proceeds in APS' next rate case, or from addressing any changes to Schedule 3 proposed by others in this rate case."

Q. Did Staff consider the arguments made by the representatives from Arizonans for Fair Power Policy?

A. Yes. Staff and the other settling parties met with representatives from Arizonans for Fair Power Policy to discuss their concerns during the Settlement negotiations. In addition, Staff had at least one other meeting with their representatives regarding their concerns and the Commissions processes in this case. Staff also recently participated in a deposition conducted by APS of the author of a document entitled "Arizona Utilities – Modifications to Infrastructure Extension Policies, Impact Analysis" prepared by Elliott D. Pollack & Company, that was filed by Arizonans for Fair Power Policy in this docket, and which is referenced by some of the persons who are opposing the Settlement Agreement? A copy of the transcript of that deposition was filed with APS' witness Ewen's Reply Testimony on August 6, 2009.

Q. You mentioned that the Settlement Agreement contained some important changes to APS' tariff for line extensions. What are those changes?

A. As specified in Settlement paragraph 10.6, the System Facilities Charge proposed by APS is withdrawn, and as provided in paragraph 10.7, APS will submit a revised Schedule 3 that includes the modifications specified there, including a clarified definition of Local Facilities, a Schedule of Charges, a provision that quotes to customers will be itemized, and procedures for refunding amounts to customers when additional customers connect to a customer-funded line extension. Staff witness Barbara Keene can provide further details concerning these changes.

Q. Does Staff support the Settlement Agreement as written?

A. Yes. The Settlement Agreement is an integrated document that resulted from several months of intensive negotiations, and which incorporates a hard-reached consensus that

1 balances a wide range of differing interests. Staff thus supports the adoption of the
2 Settlement Agreement, without modification.
3
4 **Q. Does this conclude your Reply Testimony?**
5 A. Yes, it does.

S-15

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

REPLY TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

AUGUST 13, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 1

TREATMENT OF SCHEDULE 3 2

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My Reply Testimony in support of the Settlement addresses accounting and ratemaking issues related to Schedule 3 as provided for in the Settlement Agreement. The Settlement Agreement changes the treatment for Schedule 3 receipts to account for them as revenue rather than Contributions in Aid of Construction ("CIAC").

Several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, have filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

In the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities, including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these electric utilities. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy regarding payments for line extensions.

The testimony filed by the parties in opposition to the Settlement does not contest or object to the treatment of accounting for Schedule 3 receipts as revenue. Their recommendation to reinstate a free footage allowance for APS would, however, directly impact the amounts that APS has projected it would receive under Schedule 3 as revenue.

The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document. Specifically, Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding receipts for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the amount of revenue that APS has projected for revenue from Schedule 3. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." Consequently, under this provision of the Settlement Agreement, reinstituting a free footage allowance would mean a higher rate increase for APS' existing customers.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled Direct Testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding, and testimony in support of the Settlement Agreement that was filed on July 1, 2009?

A. Yes.

Q. What is the purpose of your Reply Testimony in support of the Settlement?

A. The purpose of my Reply Testimony in support of the Settlement is to address how the Settlement Agreement provides for the accounting and ratemaking treatment of line extensions in response to testimony filed by various individuals on or about July 22, 2009 in opposition to the Settlement.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your Reply Testimony?

A. My Reply Testimony addresses the accounting and ratemaking aspects of the Treatment of Schedule 3 provisions of the Settlement Agreement.

TREATMENT OF SCHEDULE 3

Q. Please briefly summarize your understanding of the main concern identified in the testimony that was filed in opposition to the Settlement Agreement.

A. On or about July 22, 2009, several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

Q. Has the elimination of a free footage allowance for line extensions been an issue previously in other cases before the Commission?

A. Yes. It was an issue in the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these utilities. Consequently, the elimination of the free footage allowance for APS line extensions is not a new issue in this case.

Q. Arizonans for Fair Power Policy propose that the Commission change its current policy of no free footage allowance for line extensions. Does the Settlement Agreement maintain the Commission's current policy regarding line extensions?

A. Yes. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy of no free footage allowance for line extensions.

Q. Does the Settlement Agreement result in a change to the Commission's current policy of no free footage allowance for line extensions.

A. No.

Q. Do the settling parties propose a change to the accounting treatment of receipts under Schedule 3?

A. Yes. The settling parties are proposing to treat the Schedule 3 receipts as revenue instead of CIAC.

Q. How significant is Section X to the Settlement Agreement?

A. Section X mitigated the need for a higher rate increase. The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document.

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in the Settlement Agreement at paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Are the settling parties proposing any other changes to Schedule 3 other than the accounting treatment of the Schedule 3 receipts?

A. Yes. The Settlement Agreement proposes some important changes to the terms and conditions contained in the Schedule 3 tariff.

Q. Do the parties that are opposing the Settlement Agreement appear to object to the accounting by APS of Schedule 3 receipts as revenue, as provided for in paragraph 10.1?

A. No. Their concern focused to be focused on the restoration of a free footage allowance for APS' line extensions. They do not appear to object to the accounting treatment provided for Schedule 3 receipts in paragraph 10.1 of the Settlement Agreement.

Q. Would the recommendations of parties that are opposing the Settlement Agreement affect the amount of revenue that APS has projected for Schedule 3 receipts?

A. Yes. While the testimony filed by the parties in opposition to the Settlement does not appear to contest or object to the treatment of APS accounting for Schedule 3 receipts as revenue, their recommendation to reinstate a free footage allowance for APS would directly impact the amounts that APS has projected it would receive under Schedule 3. All other things being equal, if a free footage allowance were reinstated for APS, the amount of Schedule 3 receipts to APS would be lower, and the amount of rate increase to existing customers would be higher.

Q. How could the recommendations of parties that are opposing the Settlement Agreement result in a larger rate increase to existing APS customers?

A. The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding payments for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the Settlement Agreement. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." In other words, if Schedule 3 receipts (which APS would be accounting for as revenue) decrease, then another source of revenue, specifically an additional base rate increase, would need to occur in order for the change to be "revenue neutral." Consequently, under this provision, reinstituting a free footage allowance would mean a higher base rate increase for APS' existing customers.

Q. Do you have some estimates of how a reinstatement of a free footage allowance for APS' line extensions could affect the amount of rate increase provided for in the Settlement Agreement?

A. Yes. I should caution that these amounts were provided by APS in the Company's responsive letter to Chairman Mayes dated June 25, 2009, and are estimates. Nevertheless, such estimates appear to be consistent with the figures that were provided by APS and discussed by the Signatories to the Settlement Agreement.

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 by customer requesting the line extension if over $25,000.	$ 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	$ 28,000	$ 33,000	$ 47,000
100 ft. – up to $5,000	$ 173,000	$ 198,000	$ 289,000
500 ft. – up to $10,000	$ 2,274,000	$ 2,614,000	$ 3,816,000
750 ft. – up to $10,000	$ 2,660,000	$ 3,050,000	$ 4,460,000
Scenario 3 – Free footage approach subject to an investment cap.			
50 ft. but not more than $5,000	$ 63,000	$ 71,000	$ 101,000
100 ft. but not more than $5,000	$ 334,000	$ 377,000	$ 540,000
500 ft. but not more than $10,000	$ 2,350,000	$ 2,700,000	$ 3,936,000
750 ft. but not more than $10,000	$ 5,120,000	$ 5,880,000	$ 8,590,000
Scenario 4 - $5,000 equipment allowance.	$ 3,700,000	$ 4,090,000	$ 5,740,000

Q. What would be the impact on the Settlement Agreement if a different scenario was adopted?

A. If a different line extension scenario were to be adopted, the above table also shows the amount of estimated additional revenue increases that would be required pursuant to paragraph 10.3 of the Settlement Agreement which provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral."

Q. In terms of a change to the free footage allowance, would the recommendations of parties that are opposing the Settlement Agreement result in APS' tariff for line extensions being inconsistent with the other large electric utilities, including TEP and UNS Electric, that are regulated by this Commission?

A. Yes. One thing that the Commission may want to consider is that, if a free footage allowance were to be reinstated at this time for APS, this would result in APS' line extension provision being different in that respect from the line extension tariffs of TEP and UNS Electric where free footage allowances have been eliminated by the Commission.

Q. Does the Settlement Agreement result in APS' tariff for line extensions forever being "set in stone"?

A. No. The Settlement Agreement at Section II-A provides for a rate case filing plan, and Section X, paragraph 10.4, which specifically addresses Schedule 3, provides that: "Nothing in this Section of the Agreement is intended to prevent any Signatory from proposing a different treatment for Schedule 3 proceeds in APS' next rate case, or from addressing any changes to Schedule 3 proposed by others in this rate case."

Q. Did Staff consider the arguments made by the representatives from Arizonans for Fair Power Policy?

A. Yes. Staff and the other settling parties met with representatives from Arizonans for Fair Power Policy to discuss their concerns during the Settlement negotiations. In addition, Staff had at least one other meeting with their representatives regarding their concerns and the Commissions processes in this case. Staff also recently participated in a deposition conducted by APS of the author of a document entitled "Arizona Utilities – Modifications to Infrastructure Extension Policies, Impact Analysis" prepared by Elliott D. Pollack & Company, that was filed by Arizonans for Fair Power Policy in this docket, and which is referenced by some of the persons who are opposing the Settlement Agreement? A copy of the transcript of that deposition was filed with APS' witness Ewen's Reply Testimony on August 6, 2009.

Q. You mentioned that the Settlement Agreement contained some important changes to APS' tariff for line extensions. What are those changes?

A. As specified in Settlement paragraph 10.6, the System Facilities Charge proposed by APS is withdrawn, and as provided in paragraph 10.7, APS will submit a revised Schedule 3 that includes the modifications specified there, including a clarified definition of Local Facilities, a Schedule of Charges, a provision that quotes to customers will be itemized, and procedures for refunding amounts to customers when additional customers connect to a customer-funded line extension. Staff witness Barbara Keene can provide further details concerning these changes.

Q. Does Staff support the Settlement Agreement as written?

A. Yes. The Settlement Agreement is an integrated document that resulted from several months of intensive negotiations, and which incorporates a hard-reached consensus that

1 balances a wide range of differing interests. Staff thus supports the adoption of the
2 Settlement Agreement, without modification.
3
4 **Q. Does this conclude your Reply Testimony?**
5 A. Yes, it does.

S-15

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

REPLY TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

AUGUST 13, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 1

TREATMENT OF SCHEDULE 3 2

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My Reply Testimony in support of the Settlement addresses accounting and ratemaking issues related to Schedule 3 as provided for in the Settlement Agreement. The Settlement Agreement changes the treatment for Schedule 3 receipts to account for them as revenue rather than Contributions in Aid of Construction ("CIAC").

Several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, have filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

In the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities, including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these electric utilities. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy regarding payments for line extensions.

The testimony filed by the parties in opposition to the Settlement does not contest or object to the treatment of accounting for Schedule 3 receipts as revenue. Their recommendation to reinstate a free footage allowance for APS would, however, directly impact the amounts that APS has projected it would receive under Schedule 3 as revenue.

The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document. Specifically, Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding receipts for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the amount of revenue that APS has projected for revenue from Schedule 3. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." Consequently, under this provision of the Settlement Agreement, reinstituting a free footage allowance would mean a higher rate increase for APS' existing customers.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled Direct Testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding, and testimony in support of the Settlement Agreement that was filed on July 1, 2009?

A. Yes.

Q. What is the purpose of your Reply Testimony in support of the Settlement?

A. The purpose of my Reply Testimony in support of the Settlement is to address how the Settlement Agreement provides for the accounting and ratemaking treatment of line extensions in response to testimony filed by various individuals on or about July 22, 2009 in opposition to the Settlement.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your Reply Testimony?

A. My Reply Testimony addresses the accounting and ratemaking aspects of the Treatment of Schedule 3 provisions of the Settlement Agreement.

TREATMENT OF SCHEDULE 3

Q. Please briefly summarize your understanding of the main concern identified in the testimony that was filed in opposition to the Settlement Agreement.

A. On or about July 22, 2009, several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

Q. Has the elimination of a free footage allowance for line extensions been an issue previously in other cases before the Commission?

A. Yes. It was an issue in the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these utilities. Consequently, the elimination of the free footage allowance for APS line extensions is not a new issue in this case.

Q. Arizonans for Fair Power Policy propose that the Commission change its current policy of no free footage allowance for line extensions. Does the Settlement Agreement maintain the Commission's current policy regarding line extensions?

A. Yes. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy of no free footage allowance for line extensions.

Q. Does the Settlement Agreement result in a change to the Commission's current policy of no free footage allowance for line extensions.

A. No.

Q. Do the settling parties propose a change to the accounting treatment of receipts under Schedule 3?

A. Yes. The settling parties are proposing to treat the Schedule 3 receipts as revenue instead of CIAC.

Q. How significant is Section X to the Settlement Agreement?

A. Section X mitigated the need for a higher rate increase. The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document.

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in the Settlement Agreement at paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Are the settling parties proposing any other changes to Schedule 3 other than the accounting treatment of the Schedule 3 receipts?

A. Yes. The Settlement Agreement proposes some important changes to the terms and conditions contained in the Schedule 3 tariff.

Q. Do the parties that are opposing the Settlement Agreement appear to object to the accounting by APS of Schedule 3 receipts as revenue, as provided for in paragraph 10.1?

A. No. Their concern focused to be focused on the restoration of a free footage allowance for APS' line extensions. They do not appear to object to the accounting treatment provided for Schedule 3 receipts in paragraph 10.1 of the Settlement Agreement.

Q. Would the recommendations of parties that are opposing the Settlement Agreement affect the amount of revenue that APS has projected for Schedule 3 receipts?

A. Yes. While the testimony filed by the parties in opposition to the Settlement does not appear to contest or object to the treatment of APS accounting for Schedule 3 receipts as revenue, their recommendation to reinstate a free footage allowance for APS would directly impact the amounts that APS has projected it would receive under Schedule 3. All other things being equal, if a free footage allowance were reinstated for APS, the amount of Schedule 3 receipts to APS would be lower, and the amount of rate increase to existing customers would be higher.

Q. How could the recommendations of parties that are opposing the Settlement Agreement result in a larger rate increase to existing APS customers?

A. The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding payments for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the Settlement Agreement. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." In other words, if Schedule 3 receipts (which APS would be accounting for as revenue) decrease, then another source of revenue, specifically an additional base rate increase, would need to occur in order for the change to be "revenue neutral." Consequently, under this provision, reinstituting a free footage allowance would mean a higher base rate increase for APS' existing customers.

Q. Do you have some estimates of how a reinstatement of a free footage allowance for APS' line extensions could affect the amount of rate increase provided for in the Settlement Agreement?

A. Yes. I should caution that these amounts were provided by APS in the Company's responsive letter to Chairman Mayes dated June 25, 2009, and are estimates. Nevertheless, such estimates appear to be consistent with the figures that were provided by APS and discussed by the Signatories to the Settlement Agreement.

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 by customer requesting the line extension if over $25,000.	$ 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	$ 28,000	$ 33,000	$ 47,000
100 ft. – up to $5,000	$ 173,000	$ 198,000	$ 289,000
500 ft. – up to $10,000	$ 2,274,000	$ 2,614,000	$ 3,816,000
750 ft. – up to $10,000	$ 2,660,000	$ 3,050,000	$ 4,460,000
Scenario 3 – Free footage approach subject to an investment cap.			
50 ft. but not more than $5,000	$ 63,000	$ 71,000	$ 101,000
100 ft. but not more than $5,000	$ 334,000	$ 377,000	$ 540,000
500 ft. but not more than $10,000	$ 2,350,000	$ 2,700,000	$ 3,936,000
750 ft. but not more than $10,000	$ 5,120,000	$ 5,880,000	$ 8,590,000
Scenario 4 - $5,000 equipment allowance.	$ 3,700,000	$ 4,090,000	$ 5,740,000

Q. What would be the impact on the Settlement Agreement if a different scenario was adopted?

A. If a different line extension scenario were to be adopted, the above table also shows the amount of estimated additional revenue increases that would be required pursuant to paragraph 10.3 of the Settlement Agreement which provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral."

Q. In terms of a change to the free footage allowance, would the recommendations of parties that are opposing the Settlement Agreement result in APS' tariff for line extensions being inconsistent with the other large electric utilities, including TEP and UNS Electric, that are regulated by this Commission?

A. Yes. One thing that the Commission may want to consider is that, if a free footage allowance were to be reinstated at this time for APS, this would result in APS' line extension provision being different in that respect from the line extension tariffs of TEP and UNS Electric where free footage allowances have been eliminated by the Commission.

Q. Does the Settlement Agreement result in APS' tariff for line extensions forever being "set in stone"?

A. No. The Settlement Agreement at Section II-A provides for a rate case filing plan, and Section X, paragraph 10.4, which specifically addresses Schedule 3, provides that: "Nothing in this Section of the Agreement is intended to prevent any Signatory from proposing a different treatment for Schedule 3 proceeds in APS' next rate case, or from addressing any changes to Schedule 3 proposed by others in this rate case."

Q. Did Staff consider the arguments made by the representatives from Arizonans for Fair Power Policy?

A. Yes. Staff and the other settling parties met with representatives from Arizonans for Fair Power Policy to discuss their concerns during the Settlement negotiations. In addition, Staff had at least one other meeting with their representatives regarding their concerns and the Commissions processes in this case. Staff also recently participated in a deposition conducted by APS of the author of a document entitled "Arizona Utilities – Modifications to Infrastructure Extension Policies, Impact Analysis" prepared by Elliott D. Pollack & Company, that was filed by Arizonans for Fair Power Policy in this docket, and which is referenced by some of the persons who are opposing the Settlement Agreement? A copy of the transcript of that deposition was filed with APS' witness Ewen's Reply Testimony on August 6, 2009.

Q. You mentioned that the Settlement Agreement contained some important changes to APS' tariff for line extensions. What are those changes?

A. As specified in Settlement paragraph 10.6, the System Facilities Charge proposed by APS is withdrawn, and as provided in paragraph 10.7, APS will submit a revised Schedule 3 that includes the modifications specified there, including a clarified definition of Local Facilities, a Schedule of Charges, a provision that quotes to customers will be itemized, and procedures for refunding amounts to customers when additional customers connect to a customer-funded line extension. Staff witness Barbara Keene can provide further details concerning these changes.

Q. Does Staff support the Settlement Agreement as written?

A. Yes. The Settlement Agreement is an integrated document that resulted from several months of intensive negotiations, and which incorporates a hard-reached consensus that

balances a wide range of differing interests. Staff thus supports the adoption of the Settlement Agreement, without modification.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

S-15

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

REPLY TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

AUGUST 13, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 1

TREATMENT OF SCHEDULE 3 2

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My Reply Testimony in support of the Settlement addresses accounting and ratemaking issues related to Schedule 3 as provided for in the Settlement Agreement. The Settlement Agreement changes the treatment for Schedule 3 receipts to account for them as revenue rather than Contributions in Aid of Construction ("CIAC").

Several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, have filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

In the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities, including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these electric utilities. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy regarding payments for line extensions.

The testimony filed by the parties in opposition to the Settlement does not contest or object to the treatment of accounting for Schedule 3 receipts as revenue. Their recommendation to reinstate a free footage allowance for APS would, however, directly impact the amounts that APS has projected it would receive under Schedule 3 as revenue.

The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document. Specifically, Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding receipts for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the amount of revenue that APS has projected for revenue from Schedule 3. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." Consequently, under this provision of the Settlement Agreement, reinstituting a free footage allowance would mean a higher rate increase for APS' existing customers.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled Direct Testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding, and testimony in support of the Settlement Agreement that was filed on July 1, 2009?

A. Yes.

Q. What is the purpose of your Reply Testimony in support of the Settlement?

A. The purpose of my Reply Testimony in support of the Settlement is to address how the Settlement Agreement provides for the accounting and ratemaking treatment of line extensions in response to testimony filed by various individuals on or about July 22, 2009 in opposition to the Settlement.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your Reply Testimony?

A. My Reply Testimony addresses the accounting and ratemaking aspects of the Treatment of Schedule 3 provisions of the Settlement Agreement.

TREATMENT OF SCHEDULE 3

Q. Please briefly summarize your understanding of the main concern identified in the testimony that was filed in opposition to the Settlement Agreement.

A. On or about July 22, 2009, several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

Q. Has the elimination of a free footage allowance for line extensions been an issue previously in other cases before the Commission?

A. Yes. It was an issue in the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these utilities. Consequently, the elimination of the free footage allowance for APS line extensions is not a new issue in this case.

Q. Arizonans for Fair Power Policy propose that the Commission change its current policy of no free footage allowance for line extensions. Does the Settlement Agreement maintain the Commission's current policy regarding line extensions?

A. Yes. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy of no free footage allowance for line extensions.

Q. Does the Settlement Agreement result in a change to the Commission's current policy of no free footage allowance for line extensions.

A. No.

Q. Do the settling parties propose a change to the accounting treatment of receipts under Schedule 3?

A. Yes. The settling parties are proposing to treat the Schedule 3 receipts as revenue instead of CIAC.

Q. How significant is Section X to the Settlement Agreement?

A. Section X mitigated the need for a higher rate increase. The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document.

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in the Settlement Agreement at paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Are the settling parties proposing any other changes to Schedule 3 other than the accounting treatment of the Schedule 3 receipts?

A. Yes. The Settlement Agreement proposes some important changes to the terms and conditions contained in the Schedule 3 tariff.

Q. Do the parties that are opposing the Settlement Agreement appear to object to the accounting by APS of Schedule 3 receipts as revenue, as provided for in paragraph 10.1?

A. No. Their concern focused to be focused on the restoration of a free footage allowance for APS' line extensions. They do not appear to object to the accounting treatment provided for Schedule 3 receipts in paragraph 10.1 of the Settlement Agreement.

Q. Would the recommendations of parties that are opposing the Settlement Agreement affect the amount of revenue that APS has projected for Schedule 3 receipts?

A. Yes. While the testimony filed by the parties in opposition to the Settlement does not appear to contest or object to the treatment of APS accounting for Schedule 3 receipts as revenue, their recommendation to reinstate a free footage allowance for APS would directly impact the amounts that APS has projected it would receive under Schedule 3. All other things being equal, if a free footage allowance were reinstated for APS, the amount of Schedule 3 receipts to APS would be lower, and the amount of rate increase to existing customers would be higher.

Q. How could the recommendations of parties that are opposing the Settlement Agreement result in a larger rate increase to existing APS customers?

A. The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding payments for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the Settlement Agreement. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." In other words, if Schedule 3 receipts (which APS would be accounting for as revenue) decrease, then another source of revenue, specifically an additional base rate increase, would need to occur in order for the change to be "revenue neutral." Consequently, under this provision, reinstituting a free footage allowance would mean a higher base rate increase for APS' existing customers.

Q. Do you have some estimates of how a reinstatement of a free footage allowance for APS' line extensions could affect the amount of rate increase provided for in the Settlement Agreement?

A. Yes. I should caution that these amounts were provided by APS in the Company's responsive letter to Chairman Mayes dated June 25, 2009, and are estimates. Nevertheless, such estimates appear to be consistent with the figures that were provided by APS and discussed by the Signatories to the Settlement Agreement.

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 by customer requesting the line extension if over $25,000.	$ 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	$ 28,000	$ 33,000	$ 47,000
100 ft. – up to $5,000	$ 173,000	$ 198,000	$ 289,000
500 ft. – up to $10,000	$ 2,274,000	$ 2,614,000	$ 3,816,000
750 ft. – up to $10,000	$ 2,660,000	$ 3,050,000	$ 4,460,000
Scenario 3 – Free footage approach subject to an investment cap.			
50 ft. but not more than $5,000	$ 63,000	$ 71,000	$ 101,000
100 ft. but not more than $5,000	$ 334,000	$ 377,000	$ 540,000
500 ft. but not more than $10,000	$ 2,350,000	$ 2,700,000	$ 3,936,000
750 ft. but not more than $10,000	$ 5,120,000	$ 5,880,000	$ 8,590,000
Scenario 4 - $5,000 equipment allowance.	$ 3,700,000	$ 4,090,000	$ 5,740,000

Q. What would be the impact on the Settlement Agreement if a different scenario was adopted?

A. If a different line extension scenario were to be adopted, the above table also shows the amount of estimated additional revenue increases that would be required pursuant to paragraph 10.3 of the Settlement Agreement which provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral."

Q. In terms of a change to the free footage allowance, would the recommendations of parties that are opposing the Settlement Agreement result in APS' tariff for line extensions being inconsistent with the other large electric utilities, including TEP and UNS Electric, that are regulated by this Commission?

A. Yes. One thing that the Commission may want to consider is that, if a free footage allowance were to be reinstated at this time for APS, this would result in APS' line extension provision being different in that respect from the line extension tariffs of TEP and UNS Electric where free footage allowances have been eliminated by the Commission.

Q. Does the Settlement Agreement result in APS' tariff for line extensions forever being "set in stone"?

A. No. The Settlement Agreement at Section II-A provides for a rate case filing plan, and Section X, paragraph 10.4, which specifically addresses Schedule 3, provides that: "Nothing in this Section of the Agreement is intended to prevent any Signatory from proposing a different treatment for Schedule 3 proceeds in APS' next rate case, or from addressing any changes to Schedule 3 proposed by others in this rate case."

Q. Did Staff consider the arguments made by the representatives from Arizonans for Fair Power Policy?

A. Yes. Staff and the other settling parties met with representatives from Arizonans for Fair Power Policy to discuss their concerns during the Settlement negotiations. In addition, Staff had at least one other meeting with their representatives regarding their concerns and the Commissions processes in this case. Staff also recently participated in a deposition conducted by APS of the author of a document entitled "Arizona Utilities – Modifications to Infrastructure Extension Policies, Impact Analysis" prepared by Elliott D. Pollack & Company, that was filed by Arizonans for Fair Power Policy in this docket, and which is referenced by some of the persons who are opposing the Settlement Agreement? A copy of the transcript of that deposition was filed with APS' witness Ewen's Reply Testimony on August 6, 2009.

Q. You mentioned that the Settlement Agreement contained some important changes to APS' tariff for line extensions. What are those changes?

A. As specified in Settlement paragraph 10.6, the System Facilities Charge proposed by APS is withdrawn, and as provided in paragraph 10.7, APS will submit a revised Schedule 3 that includes the modifications specified there, including a clarified definition of Local Facilities, a Schedule of Charges, a provision that quotes to customers will be itemized, and procedures for refunding amounts to customers when additional customers connect to a customer-funded line extension. Staff witness Barbara Keene can provide further details concerning these changes.

Q. Does Staff support the Settlement Agreement as written?

A. Yes. The Settlement Agreement is an integrated document that resulted from several months of intensive negotiations, and which incorporates a hard-reached consensus that

1 balances a wide range of differing interests. Staff thus supports the adoption of the
2 Settlement Agreement, without modification.
3
4 **Q. Does this conclude your Reply Testimony?**
5 A. Yes, it does.

S-15

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE 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	)	DOCKET NO. E-01345A-08-0172

REPLY TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

AUGUST 13, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS 1

TREATMENT OF SCHEDULE 3 2

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

My Reply Testimony in support of the Settlement addresses accounting and ratemaking issues related to Schedule 3 as provided for in the Settlement Agreement. The Settlement Agreement changes the treatment for Schedule 3 receipts to account for them as revenue rather than Contributions in Aid of Construction ("CIAC").

Several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, have filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

In the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities, including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these electric utilities. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy regarding payments for line extensions.

The testimony filed by the parties in opposition to the Settlement does not contest or object to the treatment of accounting for Schedule 3 receipts as revenue. Their recommendation to reinstate a free footage allowance for APS would, however, directly impact the amounts that APS has projected it would receive under Schedule 3 as revenue.

The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document. Specifically, Section X of the Settlement Agreement at paragraph 10.1 provides for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. As stated in paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding receipts for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the amount of revenue that APS has projected for revenue from Schedule 3. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." Consequently, under this provision of the Settlement Agreement, reinstituting a free footage allowance would mean a higher rate increase for APS' existing customers.

INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously submitted prefiled Direct Testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") that was filed on December 19, 2008 in this proceeding, and testimony in support of the Settlement Agreement that was filed on July 1, 2009?

A. Yes.

Q. What is the purpose of your Reply Testimony in support of the Settlement?

A. The purpose of my Reply Testimony in support of the Settlement is to address how the Settlement Agreement provides for the accounting and ratemaking treatment of line extensions in response to testimony filed by various individuals on or about July 22, 2009 in opposition to the Settlement.

DISCUSSSION OF SPECIFIC SETTLEMENT AGREEMENT PROVISIONS

Q. What aspects of the Settlement Agreement are addressed in your Reply Testimony?

A. My Reply Testimony addresses the accounting and ratemaking aspects of the Treatment of Schedule 3 provisions of the Settlement Agreement.

TREATMENT OF SCHEDULE 3

Q. Please briefly summarize your understanding of the main concern identified in the testimony that was filed in opposition to the Settlement Agreement.

A. On or about July 22, 2009, several individuals, many with real estate interests, and a group, Arizonans for Fair Power Policy, filed testimony in opposition to the Settlement Agreement because they believe the Settlement should include a free footage allowance for line extensions under APS' Schedule 3.

Q. Has the elimination of a free footage allowance for line extensions been an issue previously in other cases before the Commission?

A. Yes. It was an issue in the last APS base rate case, as well as the last base rate cases for other Arizona electric utilities including Tucson Electric Power ("TEP") and UNS Electric, the Commission eliminated the free footage allowances for new line extensions that had previously been in place for these utilities. Consequently, the elimination of the free footage allowance for APS line extensions is not a new issue in this case.

Q. Arizonans for Fair Power Policy propose that the Commission change its current policy of no free footage allowance for line extensions. Does the Settlement Agreement maintain the Commission's current policy regarding line extensions?

A. Yes. The Settlement Agreement at paragraph 10.3 continues to maintain the Commission's current policy of no free footage allowance for line extensions.

Q. Does the Settlement Agreement result in a change to the Commission's current policy of no free footage allowance for line extensions.

A. No.

Q. Do the settling parties propose a change to the accounting treatment of receipts under Schedule 3?

A. Yes. The settling parties are proposing to treat the Schedule 3 receipts as revenue instead of CIAC.

Q. How significant is Section X to the Settlement Agreement?

A. Section X mitigated the need for a higher rate increase. The revenue that APS projects it would collect under Schedule 3 is a critical component of the Settlement Agreement, which must be viewed as an integrated document.

Q. What amounts does APS expect for Schedule 3 receipts?

A. As stated in the Settlement Agreement at paragraph 10.2, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. Are the settling parties proposing any other changes to Schedule 3 other than the accounting treatment of the Schedule 3 receipts?

A. Yes. The Settlement Agreement proposes some important changes to the terms and conditions contained in the Schedule 3 tariff.

Q. Do the parties that are opposing the Settlement Agreement appear to object to the accounting by APS of Schedule 3 receipts as revenue, as provided for in paragraph 10.1?

A. No. Their concern focused to be focused on the restoration of a free footage allowance for APS' line extensions. They do not appear to object to the accounting treatment provided for Schedule 3 receipts in paragraph 10.1 of the Settlement Agreement.

Q. Would the recommendations of parties that are opposing the Settlement Agreement affect the amount of revenue that APS has projected for Schedule 3 receipts?

A. Yes. While the testimony filed by the parties in opposition to the Settlement does not appear to contest or object to the treatment of APS accounting for Schedule 3 receipts as revenue, their recommendation to reinstate a free footage allowance for APS would directly impact the amounts that APS has projected it would receive under Schedule 3. All other things being equal, if a free footage allowance were reinstated for APS, the amount of Schedule 3 receipts to APS would be lower, and the amount of rate increase to existing customers would be higher.

Q. How could the recommendations of parties that are opposing the Settlement Agreement result in a larger rate increase to existing APS customers?

A. The Signatories to the Settlement Agreement have recognized that a change to the Commission's current policy regarding payments for line extensions, such as a modification to Schedule 3 to provide for a free footage allowance, would affect the Settlement Agreement. Paragraph 10.3 provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral." In other words, if Schedule 3 receipts (which APS would be accounting for as revenue) decrease, then another source of revenue, specifically an additional base rate increase, would need to occur in order for the change to be "revenue neutral." Consequently, under this provision, reinstituting a free footage allowance would mean a higher base rate increase for APS' existing customers.

Q. Do you have some estimates of how a reinstatement of a free footage allowance for APS' line extensions could affect the amount of rate increase provided for in the Settlement Agreement?

A. Yes. I should caution that these amounts were provided by APS in the Company's responsive letter to Chairman Mayes dated June 25, 2009, and are estimates. Nevertheless, such estimates appear to be consistent with the figures that were provided by APS and discussed by the Signatories to the Settlement Agreement.

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 by customer requesting the line extension if over $25,000.	$ 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	$ 28,000	$ 33,000	$ 47,000
100 ft. – up to $5,000	$ 173,000	$ 198,000	$ 289,000
500 ft. – up to $10,000	$ 2,274,000	$ 2,614,000	$ 3,816,000
750 ft. – up to $10,000	$ 2,660,000	$ 3,050,000	$ 4,460,000
Scenario 3 – Free footage approach subject to an investment cap.			
50 ft. but not more than $5,000	$ 63,000	$ 71,000	$ 101,000
100 ft. but not more than $5,000	$ 334,000	$ 377,000	$ 540,000
500 ft. but not more than $10,000	$ 2,350,000	$ 2,700,000	$ 3,936,000
750 ft. but not more than $10,000	$ 5,120,000	$ 5,880,000	$ 8,590,000
Scenario 4 - $5,000 equipment allowance.	$ 3,700,000	$ 4,090,000	$ 5,740,000

Q. What would be the impact on the Settlement Agreement if a different scenario was adopted?

A. If a different line extension scenario were to be adopted, the above table also shows the amount of estimated additional revenue increases that would be required pursuant to paragraph 10.3 of the Settlement Agreement which provides that, if such a change were to be instituted by the Commission, an offsetting revenue change should also be ordered so that such modifications would be "revenue neutral."

Q. In terms of a change to the free footage allowance, would the recommendations of parties that are opposing the Settlement Agreement result in APS' tariff for line extensions being inconsistent with the other large electric utilities, including TEP and UNS Electric, that are regulated by this Commission?

A. Yes. One thing that the Commission may want to consider is that, if a free footage allowance were to be reinstated at this time for APS, this would result in APS' line extension provision being different in that respect from the line extension tariffs of TEP and UNS Electric where free footage allowances have been eliminated by the Commission.

Q. Does the Settlement Agreement result in APS' tariff for line extensions forever being "set in stone"?

A. No. The Settlement Agreement at Section II-A provides for a rate case filing plan, and Section X, paragraph 10.4, which specifically addresses Schedule 3, provides that: "Nothing in this Section of the Agreement is intended to prevent any Signatory from proposing a different treatment for Schedule 3 proceeds in APS' next rate case, or from addressing any changes to Schedule 3 proposed by others in this rate case."

Q. Did Staff consider the arguments made by the representatives from Arizonans for Fair Power Policy?

A. Yes. Staff and the other settling parties met with representatives from Arizonans for Fair Power Policy to discuss their concerns during the Settlement negotiations. In addition, Staff had at least one other meeting with their representatives regarding their concerns and the Commissions processes in this case. Staff also recently participated in a deposition conducted by APS of the author of a document entitled "Arizona Utilities – Modifications to Infrastructure Extension Policies, Impact Analysis" prepared by Elliott D. Pollack & Company, that was filed by Arizonans for Fair Power Policy in this docket, and which is referenced by some of the persons who are opposing the Settlement Agreement? A copy of the transcript of that deposition was filed with APS' witness Ewen's Reply Testimony on August 6, 2009.

Q. You mentioned that the Settlement Agreement contained some important changes to APS' tariff for line extensions. What are those changes?

A. As specified in Settlement paragraph 10.6, the System Facilities Charge proposed by APS is withdrawn, and as provided in paragraph 10.7, APS will submit a revised Schedule 3 that includes the modifications specified there, including a clarified definition of Local Facilities, a Schedule of Charges, a provision that quotes to customers will be itemized, and procedures for refunding amounts to customers when additional customers connect to a customer-funded line extension. Staff witness Barbara Keene can provide further details concerning these changes.

Q. Does Staff support the Settlement Agreement as written?

A. Yes. The Settlement Agreement is an integrated document that resulted from several months of intensive negotiations, and which incorporates a hard-reached consensus that

balances a wide range of differing interests. Staff thus supports the adoption of the Settlement Agreement, without modification.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

ALL-STATE LEGAL®
EXHIBIT
S-16
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

SUPPORTING THE SETTLEMENT AGREEMENT

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 13, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

CORRECTION TO STAFF'S DIRECT TESTIMONY 1

DSM ADJUSTMENT CHARGE PLAN OF ADMINISTRATION 2

POWER SUPPLY ADJUSTMENT PLAN OF ADMINISTRATION 3

SERVICE SCHEDULE 1 4

SERVICE SCHEDULE 3 5

SERVICE SCHEDULE 4 5

SERVICE SCHEDULE 5 6

SERVICE SCHEDULE 8 6

SERVICE SCHEDULE 10 7

SERVICE SCHEDULE 15 8

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

This testimony addresses revisions to the Demand-side Management Plan of Administration, the Power Supply Adjustment Plan of Administration; and Service Schedules 1, 3, 4, 5, 8, 10, and 15.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed Direct Testimony providing support for the Settlement Agreement, addressing the Power Supply Adjustment Plan of Administration, Schedule 3, Demand-side Management ("DSM"), and Renewable Energy standard issues for Arizona Public Service Company ("APS").

Q. What is the subject matter of this testimony?

A. This testimony addresses a minor correction to Staff's Direct Testimony and APS' revisions to the following items:

- Demand-side Management Plan of Administration
- Power Supply Adjustment Plan of Administration
- Service Schedule 1 (Terms and Conditions for Standard Offer and Direct Access Services)
- Service Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services)
- Service Schedule 4 (Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service)
- Service Schedule 5 (Guidelines for Electric Curtailment)
- Service Schedule 8 (Bill Estimation)
- Service Schedule 10 (Terms and Conditions for Direct Access)
- Service Schedule 15 (Conditions Governing the Provision of Specialized Metering)

CORRECTION TO STAFF'S DIRECT TESTIMONY

Q. Do you have a correction to your Direct Testimony?

A. Yes.

Q. What is the correction?

A. On page 9, line 17 and line 21, of my Direct Testimony, the word "PSA" should be "DSMAC."

DSM ADJUSTMENT CHARGE PLAN OF ADMINISTRATION

Q. What is the DSMAC?

A. The DSMAC ("Demand-side Management Adjustment Charge") is the adjustor mechanism through which APS recovers prudently incurred DSM program and related costs incurred by APS, above the $10 million included in base rates, in connection with Commission-approved DSM programs and activities.

Q. Will the DSMAC Plan of Administration need to be revised?

A. Yes. The DSMAC Plan of Administration will need to be revised to incorporate the modifications to the DSMAC that are included in the Settlement Agreement.

Q. Was the revised DSMAC Plan of Administration filed with the Settlement Agreement?

A. No, but APS filed a revised DSMAC Plan of Administration on June 29, 2009. On August 11, 2009, APS attached a DSMAC Plan of Administration with further revisions to the Additional Supplemental Direct Settlement Testimony of APS witness David J. Rumolo.

Q. Has Staff reviewed the revised DSMAC Plan of Administration?

A. Yes. Staff has reviewed the revised DSMAC Plan of Administration filed on August 11, 2009, and finds it to be consistent with the Settlement Agreement, with one correction.

Q. What is the correction?

A. On Schedule 1 of the DSMAC Plan of Administration, the phrase "less the $10 million in base rates" should be added at the end of footnote No. 4. This correction would make it clear that only costs above the amount in base rates would be recovered through the adjustment mechanism.

Q. Does Staff have any further recommendations regarding the DSMAC Plan of Administration?

A. Yes. Staff recommends that language be added to the Plan of Administration that describes the provision in Decision No. 67744 that allows a customer with an active DSM program and usage of 20 MW or greater to file for Commission approval of an exemption from the DSMAC.

POWER SUPPLY ADJUSTMENT PLAN OF ADMINISTRATION

Q. What is the Power Supply Adjustment ("PSA")?

A. The PSA is the adjustor mechanism through which APS collects or returns the difference between actual fuel and purchased power costs and the amount included in base rates.

Q. Will the PSA Plan of Administration need to be revised?

A. Yes. The PSA Plan of Administration will need to be revised to incorporate the modifications to the PSA that are included in the Settlement Agreement.

Q. Was the revised PSA Plan of Administration filed with the Settlement Agreement?

A. No, but APS filed a revised PSA Plan of Administration on June 29, 2009. On August 11, 2009, APS attached a PSA Plan of Administration with further revisions to the Additional Supplemental Direct Settlement Testimony of APS witness David J. Rumolo.

Q. Has Staff reviewed the revised PSA Plan of Administration?

A. Yes. Staff has reviewed the revised PSA Plan of Administration filed on August 11, 2009, and finds it to be consistent with the Settlement Agreement, with two minor corrections.

Q. What are the corrections?

A. On Schedule 4 of the PSA Plan of Administration, footnote No. 2 should be deleted because it is outdated. On Schedule 5, line 8, there is an incorrect reference to footnote No. 5 that should be deleted.

SERVICE SCHEDULE 1

Q. What is Service Schedule 1?

A. Service Schedule 1 ("Schedule 1") includes APS' terms and conditions for Standard Offer and Direct Access services.

Q. Has APS proposed revisions to its Schedule 1?

A. Yes. APS filed a revised Schedule 1 on June 29, 2009.

Q. Has Staff reviewed the revised Schedule 1?

A. Yes. Staff has reviewed the revised Schedule 1 filed on June 29, 2009, and finds the revisions acceptable, with one exception.

Q. What is the exception?

A. On page 8, section 4.3.2, first line, APS has proposed replacing the word "will" with "may" in regard to correcting billing errors. Staff believes that the change would be inconsistent with A.A.C. R14-2-210.E which requires a utility to correct bills after

discovering an error. APS has indicated to Staff that it agrees with Staff that the revision should not be made.

SERVICE SCHEDULE 3

Q. What is Service Schedule 3?

A. Service Schedule 3 ("Schedule 3") is APS' line extension policy.

Q. Will Schedule 3 need to be revised?

A. Yes. Schedule 3 will need to be revised to incorporate the modifications to Schedule 3 that are included in the Settlement Agreement.

Q. Was the revised Schedule 3 filed with the Settlement Agreement?

A. No, but APS filed a revised Schedule 3 on June 29, 2009. On August 11, 2009, APS attached a Schedule 3 with further revisions to the Additional Supplemental Direct Settlement Testimony of APS witness David J. Rumolo.

Q. Has Staff reviewed the revised Schedule 3?

A. Staff is in the process of reviewing the revised Schedule 3 filed on August 11, 2009. In particular, Staff will be analyzing data to support the Schedule of Charges that is included on Attachment 1 to Schedule 3.

SERVICE SCHEDULE 4

Q. What is Service Schedule 4?

A. Service Schedule 4 ("Schedule 4") includes APS' terms and conditions for totalized metering, which is the measurement for billing purposes through one meter of the

demands and energy of a customer who receives electric service through multiple service entrances.

Q. Has APS proposed revisions to its Schedule 4?

A. Yes. APS filed a revised Schedule 4 on June 29, 2009.

Q. Has Staff reviewed the revised Schedule 4?

A. Yes. Staff has reviewed the revised Schedule 4 filed on June 29, 2009, and finds the revisions acceptable.

SERVICE SCHEDULE 5

Q. What is Service Schedule 5?

A. Service Schedule 5 ("Schedule 5") includes APS' guidelines for electric curtailment.

Q. Has APS proposed revisions to its Schedule 5?

A. Yes. APS filed a revised Schedule 5 on June 29, 2009.

Q. Has Staff reviewed the revised Schedule 5?

A. Yes. Staff has reviewed the revised Schedule 5 filed on June 29, 2009, and finds the revisions acceptable.

SERVICE SCHEDULE 8

Q. What is Service Schedule 8?

A. Service Schedule 8 ("Schedule 8") includes APS' procedures for estimating electric usage when a valid meter read cannot be obtained.

Q. Has APS proposed revisions to its Schedule 8?

A. Yes. APS filed a revised Schedule 8 on June 29, 2009. On July 17, 2009, APS attached Schedule 8 with further revisions to the Supplemental Direct Settlement Testimony of APS witness David J. Rumolo.

Q. Has Staff reviewed the revised Schedule 8?

A. Yes. Staff has reviewed the revised Schedule 8 filed on July 17, 2009, and finds the revisions acceptable, with one exception.

Q. What is the exception?

A. On page 7, section 3.2.6, last sentence and page 9, section 3.2.8.6, last sentence, the language should be clarified as follows:

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

SERVICE SCHEDULE 10

Q. What is Service Schedule 10?

A. Service Schedule 10 ("Schedule 10") includes APS' terms and conditions for Direct Access, which refers to a retail customer procuring competitive services from other providers.

Q. Has APS proposed revisions to its Schedule 10?

A. Yes. APS filed a revised Schedule 10 on June 29, 2009.

Q. Has Staff reviewed the revised Schedule 10?

A. Yes. Staff has reviewed the revised Schedule 10 filed on June 29, 2009, and finds some of the revisions acceptable.

Q. Which revisions to Schedule 10 does Staff find to be not acceptable?

A. On page 17, section 8.2.1.1, and page 18, sections 8.3 and 8.4 of Schedule 10, APS has proposed language to allow competitive suppliers to subcontract with APS for APS to provide metering and meter reading services for Direct Access customers. Staff believes that these provisions might not be consistent with the Commission's Retail Electric Competition rules. Since the topic of retail electric competition is currently under review in Docket No. E-00000A-02-0051, Staff believes that a policy change should not be made to Schedule 10 at this time.

SERVICE SCHEDULE 15

Q. What is Service Schedule 15?

A. Service Schedule 15 ("Schedule 15") provides the conditions under which APS would provide specialized metering upon customer request.

Q. Has APS proposed revisions to its Schedule 15?

A. Yes. APS filed a revised Schedule 15 on June 29, 2009.

Q. Has Staff reviewed the revised Schedule 15?

A. No. Staff has not completed its review of the revised Schedule 15.

Q. Does this conclude your Reply Testimony?

A. Yes, it does.

ALL-STATE LEGAL®
EXHIBIT
S-17
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSIO

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 ERRATA**

Staff of the Arizona Corporation Commission ("Staff"), hereby files this Notice of Errata to Ralph C. Smith's Reply Testimony filed on August 13, 2009. On page 5 of Mr. Smith's testimony, the chart entitled "Estimated Impacts to Settlement Revenue Levels of Differing Schedule 3 Scenarios for Single Residential Customer Line Extensions" contains incorrect numbers for some of the scenarios. Attached is page 5 with the corrected "Estimated Impacts to Settlement Revenue Levels of Differing Schedule 3 Scenarios for Single Residential Customer Line Extensions" table. Please use the attached page 5 in place of the original page in the docketed testimony.

RESPECTFULLY SUBMITTED this 14th day of August, 2009.

Janet Wagner, Assistant Chief Counsel
Maureen A. Scott, Senior Staff Counsel
Charles Hains, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

. . .

. . .

Original and thirteen (13) copies
of the foregoing were filed this
14th day of August, 2009 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85008

Copies of the foregoing mailed this
14th day of August, 2009 to:

Thomas L. Mumaw
Meghan H. Grabel
PINNACLE WEST CAPITAL CORPORATION
LAW DEPARTMENT
P.O. Box 53999
Phoenix, Arizona 85072-3999

William J. Maledon
OSBORN MALEDON P.A.
2929 North Central Avenue
Phoenix, Arizona 85067-6379

Robert Metli
SNELL & WILMER L.L.P.
400 East Van Buren Street
Phoenix, Arizona 85004-2202

Barbara Klemstine
Zachary Fryer
Susan Casady
ARIZONA PUBLIC SERVICE COMPANY
P.O. Box 53999
Mail Station 9708
Phoenix, Arizona 85072-3999

Michael L. Kurtz
Kurt J. Boehm
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG P.C.
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012-2913

Lawrence V. Robertson, Jr.
Attorney at Law
P.O. Box 1448
Tubac, Arizona 85646

Michael A. Curtis
William P. Sullivan
Larry K. Udall
CURTIS, GOODWIN, SULLIVAN,
UDALL & SCHWAB, P.L.C.
501 East Thomas Road
Phoenix, Arizona 85012-3205

Timothy M. Hogan
ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004

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

Michael M. Grant
GALLAGHER & KENNEDY
2575 East Camelback Road
Phoenix, Arizona 85016-9225

Gary Yaquinto
ARIZONA INVESTMENT COUNCIL
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004

Jay I. Moyes
MOYES SELLERS & SIMS
1850 North Central Avenue, Suite 1100
Phoenix, Arizona 85004-0001

David Berry
WESTERN RESOURCE ADVOCATES
P.O. Box 1064
Scottsdale, Arizona 85252

Jeff Schlegel
SWEEP Arizona Representative
1167 West Samalayuca Drive
Tucson, Arizona 85704

Jeffrey J. Woner
K.R. SALINE & ASSOC., PLC
160 North Pasadena, Suite 101
Mesa, Arizona 85201

Scott Canty, General Counsel
THE HOPI TRIBE
P.O. Box 123
Kykotsmovi, Arizona 86039

Cynthia Zwick
1940 East Luke Avenue
Phoenix, Arizona 85016

Nicholas J. Enoch
LUBIN & ENOCH, P.C.
349 North 4th Avenue
Phoenix, Arizona 85003

Carlo Dal Monte
65 Front Street, Suite 201
Nanaimo, British Columbia V9R 5H9

Barbara Wyllie-Pecora
27458 N. 128th Dr.
Peoria, Arizona 85383

Amanda Ormond
7650 S. McClintock
Suite 103-282
Tempe, Arizona 85284

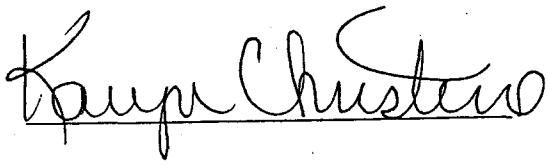
Douglas Fant
3655 W. Anthem Way
-A-109 PMB 411
Anthem, Arizona 85086

Lieutenant Colonel Karen White
AFLSA/JACL-ULT
139 Barnes Dr., Suite 1
Tyndall AFB, Florida 32403-5319

John More, Jr.
7321 North 16th Street
Phoenix, Arizona 85020

Steve Morrison
SCA TISSUE NORTH AMERICA
14005 West Old Highway 66
Bellemont, Arizona 86015

Kevin Higgins
ENERGY STRATEGIES, LLC
215 South State Street, Suite 200
Salt Lake City, Utah 84111



Q. Do you have some estimates of how a reinstatement of a free footage allowance for APS' line extensions could affect the amount of rate increase provided for in the Settlement Agreement?

A. Yes. I should caution that these amounts were provided by APS in the Company's responsive letter to Chairman Mayes dated June 25, 2009, and are estimates. Nevertheless, such estimates appear to be consistent with the figures that were provided by APS and discussed by the Signatories to the Settlement Agreement.

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 by customer requesting the line extension if over $25,000.	$ 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

EXHIBIT
S-18
admitted

MEMORANDUM

TO: Elijah O, Abinah
Assistant Director
Arizona Corporation Commission Staff

FROM: Mike Lewis, WML&A, Inc.
Ken Strobl, Technical Associates, Inc.

DATE: September 4, 2009

RE: APS Lineman Fatality, December 2, 2008

We have reviewed relevant materials that are currently available concerning the referenced fatality. These included the ADOSH report and findings concerning the incident, the APS Accident Prevention Manual ("APM"), relevant US OSHA regulations, and National Electric Safety Code ("NESC") requirements concerning work on high voltage electric facilities. In addition, we have discussed aspects of the incident with APS personnel.

Based on our preliminary reviews to date, we believe that the fatality was directly due to the failure to properly place working grounds on both sides of the immediate work area and due to insufficient analysis/recognition of the possible sources of electric energy in the immediate work area.

Working grounds are temporary conducting connections between an electric conductor or equipment and earth or to a conducting medium that serves in the place of earth. These working grounds are placed on normally electrically energized conductors and/or equipment that has been de-energized while work is being performed so as to electrically isolate the work area from unintended sources of voltage. The mandated use of working grounds for the purpose of isolating work areas is addressed in the APS Accident Prevention Manual at Chapter 13-2 (J) and (M) and in the APS Grounding Manual.

Our review indicates that there were two likely sources of the electrical energy that fatally injured the victim. These consist of: (1) voltage induced in the overhead circuit being maintained by energized Extra High Voltage ("EHV") lines parallel to and in the vicinity of the substation and (2) stored energy in the CCVT ("coupling capacitor voltage transformer") that was directly connected to the conductor being maintained and was not fully discharged of its electric energy after the main circuit was deenergized. The description of the pre-injury activities of the crew contains some aspects that call into question either of the two probable sources of electrical energy, but it appears that the CCVT is the more likely. Note the ADOSH report states that the overhead 500 Kv line had been opened at both ends the day prior to the incident and was considered "dead" by the crew. The proper placement of working grounds would have prevented the incident in either case, which is described in general terms for a work area in the APS APM.

APS personnel have informed us that they took immediate steps to contact all of their maintenance crews to review the incident and refresh aspects of the APM that would have prevented such an incident. APS personnel informed us that they are continuing to investigate the incident and that they would share their report of such when it is final, which would be after their ongoing appeal of the ADOSH findings is completed. APS personnel stated that they have a meeting with ADOSH personnel on or around August 28.

We would suggest that the Commission allow the ADOSH and APS to complete the appeal process and then revisit this at that time to evaluate if the Commission should consider any additional action.

EXHIBIT
WRA-1
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

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

Direct Testimony of

Carolyn Stewart
Red Mountain Energy Partners

On Behalf of

Western Resource Advocates

December 19, 2008

Direct Testimony of Carolyn Stewart
Docket No. E-01345A-08-0172

Table of Contents

I. INTRODUCTION 4
II. SUMMARY OF TESTIMONY 5
III. COMMISSION DECISION NO. 69663 AND APS' RESPONSE 5
IV. DEMAND RESPONSE LITERATURE REVIEW 8
V. APS' PROPOSED ET-SP RATE 11
VI. APS PROPOSED CPP-GS RATE 14
VII. POTENTIAL IMPACT OF PROPOSED ET-SP AND CPP-GS RATES ON OVERALL ENERGY CONSUMPTION 15
VIII. ENVIRONMENTAL EFFECTS OF PROPOSED ET-SP AND CPP-GS RATES 18
IX. OTHER ANTICIPATED BENEFITS OF DEMAND RESPONSE RATES 20
X. RECOMMENDATIONS 21

List of Exhibits

Qualifications of Carolyn Stewart	CTS-1
APS proposed ET-SP and GS-CPP Tariffs	CTS-2
Summary of Reports and Presentations Reviewed	CTS-3
Summary of Demand Response Program Effectiveness	CTS-4
Summary of Proposed Rates ET-SP and ET-2	CTS-5
APS Maximum Retail Load June-September 2007-2008	CTS-6
Arizona Power Plant Air Emission Rates 2006	CTS-7

DIRECT TESTIMONY OF CAROLYN T. STEWART,

RED MOUNTAIN ENERGY PARTNERS

ON BEHALF OF WESTERN RESOURCE ADVOCATES

(Docket No. E-01345A-08-0172)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Carolyn T. Stewart, 2122 E. Highland Avenue, Suite 260, Phoenix, AZ 85016.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a partner and co-owner of Red Mountain Energy Partners, a consulting firm serving clients primarily in the Southwestern U.S.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Western Resource Advocates (WRA) and I have worked closely with WRA in preparing my testimony.

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. I have more than 30 years of experience in the energy industry in the areas of utility regulatory matters, including electric utility rate development; energy strategy development; and energy project development. Prior to forming Red Mountain Energy, I served as an Associate Director at Navigant Consulting, Inc. ("NCI") in Phoenix, AZ and Chicago, IL for 8 years. Prior to joining NCI, I held various positions, over a 22-year career, at Nicor Gas, a natural gas utility serving over 2 million customers in Northern Illinois. Exhibit CTS-1 provides more detailed background information.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an independent analysis of the expected effects of APS' proposed demand response rates, which include a residential super peak

time-of-use ("TOU") rate, ET-SP, and a critical peak pricing ("CPP") rate, CPP-GS[1], for general service customers.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my testimony, I describe demand response programs and summarize Arizona Corporation Commission Decision No. 69663 (June 28, 2007) in which the Commission ordered APS to conduct a study on demand response and to submit one or more programs based upon that study, as well as APS' response to that order. I also summarize results from analyses by others on demand response pricing programs. I then assess APS' proposed rate schedules ET-SP and CPP-GS in light of experience in other regions. I evaluate the potential attractiveness of Schedule ET-SP, review analyses of demand response and energy efficiency synergies, raise the issue of whether APS' proposed demand response rates might have adverse environmental impacts, and recommend studies to obtain more information on these issues based on APS' experience with the proposed tariffs.

III. COMMISSION DECISION NO. 69663 AND APS' RESPONSE

Q. WHAT IS DEMAND RESPONSE?

A. The Federal Energy Regulatory Commission (FERC) defines demand response as actions by customers to change their consumption of electric power in response to price signals,

[1] Charles Miessner refers to this rate as GS-CPP throughout his pre-filed testimony, although the tariff sheet indicates CPP-GS.

1 incentives, or directions from grid operators.[2] The FERC explains that demand response
2 is typically an active response to prices or incentive payments. Changes in electricity use
3 are short term and centered on critical hours of the day or year when demand is high or
4 system reliability is jeopardized. Demand response programs are intended to reduce
5 customer usage during these critical periods.

6 **Q. WHAT DID THE COMMISSION ORDER CONCERNING DEMAND RESPONSE**
7 **PROGRAMS REQUIRE OF APS?**

8 A. APS was ordered to: 1) submit a Critical Peak Pricing proposal in its next rate
9 application; and 2) conduct a study to identify what types of Demand Response and Load
10 Management would be most beneficial to APS' system, relying on a cost-benefit analysis
11 based on the Societal Cost Test, and file the study and one or more cost effective program
12 proposals within one year.

13 **Q. WHAT HAS APS PROPOSED IN THIS DOCKET TO ADDRESS THE**
14 **COMMISSION ORDER?**

15 A. APS has proposed two demand response pricing programs: 1) a residential super peak
16 TOU rate ET-SP, and 2) a critical peak pricing program for general service customers,
17 CPP-GS. Charles Miessner's pre-filed testimony, beginning on page 2, line 24, also
18 indicated that APS was conducting research concerning demand response programs, but
19 had not yet completed its studies. Its research included investigation of demand-response
20 pricing programs offered by other utilities and independent system operators, reviews of
21 rate schedules offered by other utilities to identify current offerings or pilot programs,
22 and reviews of government surveys of utility demand response programs and pilot
23 projects. On November 6, 2008, APS filed a request for approval of a commercial and

[2] Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering*, Staff Report, Docket AD06-2-000, August 2006, p. 5.

industrial demand response program using an aggregator business model (Docket No. E-01345A-08-0569).

Q. PLEASE DESCRIBE APS' PROPOSED ET-SP RATE.

A. A copy of Rate Schedule ET-SP is included in Exhibit CTS-2. APS' proposed ET-SP rate is composed of Off-Peak, On-Peak, and Super-Peak pricing for summer and winter seasons. The Super Peak period applies June – August and it has the highest rates. On-peak summer rates apply from May through October, and on-peak winter rates apply the rest of the year. Summer on-peak rates are higher than winter on-peak rates. Off-peak rates are lower than on-peak rates, apply year-round, and are the same in every month. The Super Peak Summer rates apply during the hours of 3 PM to 6 PM Monday through Friday. Charles Miessner indicates in his pre-filed testimony on page 9, lines 10-11, that Rate ET-SP will be available to all residential customers that are served with advanced metering ("AMI") meters.

Q. PLEASE DESCRIBE APS' PROPOSED CPP-GS RATE.

A. Rate schedule CPP-GS is included in Exhibit CTS-2. APS' proposed rate schedule CPP-GS provides a high price ($0.40 per kWh) during critical hours, called by APS one day in advance that occur between 2 PM and 7 PM Monday through Friday, from June through September. Critical hours are limited to 18 days per year, 5 hours per day, and 90 hours per year. Rate CPP-GS also provides discounts for participating customers on all monthly kWh usage of between $(0.011755) and $(0.014892), depending on the otherwise applicable schedule.[3] Eligible customers must demonstrate the ability to reduce usage during critical hours by at least 200 kW, and submit a load reduction plan, which APS will approve in advance. APS is proposing to require interval metering, as well as limit participation to 100 customers for the first two years of program eligibility.

[3] According to Mr. Miessner, the discounts apply only during the months of June through September (conversation December 9, 2008). The tariff should be revised to clarify the period in which discounts apply.

IV. DEMAND RESPONSE LITERATURE REVIEW

Q. HOW DID YOU EVALUATE THE POTENTIAL IMPACTS OF APS' PROPOSED DEMAND RESPONSE TARIFFS?

A. I conducted a review of the literature on experience with similar programs in other jurisdictions.

Q. WHAT PRESENTATIONS AND STUDIES DID YOU REVIEW?

A. I reviewed eight presentations of demand response programs made between 2004 and 2008, and ten detailed reports on demand response programs written during the same time period. Exhibit CTS-3 summarizes each. One of the pervasive themes of the literature is the economic benefit of providing consumers with more timely and more accurate price signals reflecting the power supplier's marginal costs and the value of automated metering equipment in providing those benefits.

Q. WHAT DEMAND RESPONSE PROGRAMS WERE ANALYZED IN THE MATERIALS YOU REVIEWED?

A. The demand response programs studied included those conducted by electric utilities in California, the Carolinas, Florida, Georgia, Idaho, Illinois, Missouri, New Jersey, New York, Wisconsin, Ontario Canada, and Australia.

Q. HOW MANY UTILITIES CURRENTLY OFFER DEMAND RESPONSE PROGRAMS OR TARIFFS?

A. According to a Federal Energy Regulatory Commission ("FERC") study, item R-5 on Exhibit CTS-3, completed in 2006, more than 250 time-based rate programs were being offered. At that time, 187 utilities offered time-of-use rates, 25 utilities offered critical peak pricing tariffs or pilots, and 47 offered real-time-pricing programs. Of the time-of-use rates, 148 were offered to residential customers, and the remaining 39 were for

nonresidential customers. Most of the critical peak pricing program offerings were pilots. Of the 47 real time pricing programs, the majority were offered by investor-owned utilities outside of the Western Electricity Coordinating Council region.

Q. HOW MANY CUSTOMERS PARTICIPATE IN DEMAND-RESPONSE PROGRAMS ACROSS THE U.S. TODAY?

A. According to the FERC study, about five percent of US electric customers participate in demand response programs.

Q. WHAT MEASURES OF EFFECTIVENESS WERE USED TO EVALUATE DEMAND RESPONSE PROGRAM SUCCESS?

A. As summarized in Exhibit CTS-4, program effectiveness was typically measured by reductions in utility peak load. In some studies, energy usage, and customer bill impacts were also measured.

Q. IS REDUCTION IN OVERALL ENERGY USAGE A MEASURE OF SUCCESS IN DEMAND RESPONSE PROGRAMS?

A. In general, no. Demand response programs are primarily intended to reduce peak demand. A comprehensive study completed by the American Council for an Energy Efficient Economy ("ACEEE"), item R-7 in Exhibit CTS-3, found almost no published research on the issue of how demand response programs affect energy use during off-peak periods and overall building/facility use and energy efficiency.

Q. DID THE FERC STUDY DISCUSS ANY ARIZONA UTILITY DEMAND RESPONSE PROGRAM RESULTS?

A. Yes. The FERC study highlighted the time-of-use programs of APS and Salt River Project. The study cited both as "having residential participation rates that approach one-third of their customers".[4] According to the 2006 study, APS' residential customer

[4] Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering*, Staff Report, Docket AD06-2-000, August 2006, p. 55.

1 participation was 332,823. Gregory DeLizio's prefiled testimony indicates on page 26,
2 beginning on line 1, that as of December 2007, nearly 453,000 customers were
3 participating in a time-of-use rate. APS also indicated that in terms of percentage and
4 total number of customers, APS had the most successful residential time-of-use program
5 in the U.S.

6 **Q. DID ANY OF THE STUDIES PROVIDE SUMMARY DATA ON THE**
7 **EFFECTIVENESS OF SUPER PEAK PRICING RATES?**

8 A. None of the studies I reviewed included data on rates with pre-determined Super Peak
9 rate periods similar to proposed rate ET-SP. However, one Ameren pilot, summarized in
10 a January 2008 Edison Electric Institute ("EEI") study, item R-1 in Exhibit CTS-3,
11 included a time-of-use rate with three pricing tiers, but with significantly different pricing
12 than APS has proposed. The three-tiered time-of-use rate pricing had lower differentials
13 between off-peak, mid-peak and on-peak periods than APS has proposed, and the
14 Ameren tariff resulted in modest (less than 1%) shifts of energy usage from mid-peak and
15 on-peak periods to off-peak periods. A Brattle Group presentation in March 2008, item
16 P-2 in Exhibit CTS-3, provided results that demonstrated the impact with, and without,
17 use of advanced metering technology on time-of-use rates. This study indicated overall
18 load reduction results achieved in four time-of-use pilots without technology from 2% to
19 as high as 13%, and time-of-use load reduction results achieved in four pilots with
20 automated metering technology from 18% to 32%. In Gregory DeLizio's prefiled
21 testimony, page 35, beginning on line 23, he indicates that APS' introduction of a "super
22 peak" rate is very analogous to critical peak pricing proposals in other jurisdictions, and
23 may result in the same or similar impacts on peak load, which are discussed below.

24 **Q. DID ANY OF THE STUDIES PROVIDE SUMMARY DATA ON THE**
25 **EFFECTIVENESS OF CRITICAL PEAK PRICING RATES?**

A. Yes. Several variations of critical peak pricing rates have been evaluated in pilots. These include a CPP-fixed rate, in which the time and duration of the price increase are pre-determined, but the days with critical events are called and are not established in advance. With CPP-variable rates, the time, duration, and day of price increases are not predetermined. The ACEEE August 2004 California pilot presentation, item P-8 in Exhibit CTS-3, the Charles River Associates report, item P-6 in Exhibit CTS-3, and the FERC study, item R-5 in Exhibit CTS-3, included results for several critical peak pricing programs evaluated in the statewide California pilot. Results varied from peak load reductions for participating customers of ~ 12% for CPP-fixed rates during critical peak events, and up to ~45% reductions for CPP-variable rates for customers with smart thermostats. Critical peak pricing program load reduction results achieved without technology were reported to reach just under 50% with the majority between 10-20%, and critical peak pricing program load reduction results achieved with technology reached over 50%, with the majority over 20%.

Q. DID CRITICAL PEAK PRICING PROGRAM PEAK LOAD REDUCTION RESULTS VARY BY CLIMATE?

A. Yes. The ACEEE August 2004 California pilot results summary indicated ~16-17% peak load reductions for CPP-fixed rate customers in Climate Zone 4, which is most comparable to Phoenix, compared with California statewide pilot program peak load reductions of 12%.

V. APS' PROPOSED ET-SP RATE

Q. WHAT IS SUPER PEAK TIME-OF-USE PRICING?

A. Super peak time-of-use pricing is similar to typical time-of-use pricing, but includes an additional critical peak period with a higher super peak period charge per kWh used during the pre-determined super peak period.

Q. HOW DOES THE APS PROPOSED ET-SP RATE COMPARE WITH APS' EXISTING TIME-OF-USE RATES?

A. As previously summarized in my testimony, APS' proposed ET-SP rate is a typical time-of-use rate, with a designated super peak rate during certain hours in the summer. The structure of ET-SP is similar to APS' residential time-of-use Rate ET-2, but establishes a premium super peak price for weekday afternoons from 3 p.m. to 6 p.m. during June, July and August. Summer and Winter On-Peak rates are the same on the ET-2 and ET-SP tariffs. ET-SP Off-Peak rates are lower than those proposed for rate ET-2, as indicated in Exhibit CTS-5.

Q. WHAT BENEFITS DOES SUPER PEAK TIME-OF-USE PRICING PROVIDE?

A. If the super peak tariff is successful at shifting load away from the super peak hours, APS would be able to avoid or defer generating capacity additions and avoid expensive fuel or purchased power costs during peak periods, thereby lowering its costs and eventually lowering rates.

Q. IS THE PROPOSED SUPER PEAK TIME PERIOD FROM 3-6 PM APPROPRIATE GIVEN HISTORICAL APS CUSTOMER PEAK LOAD USAGE?

A. Yes. Exhibit CTS-6 shows that APS' retail load peaks in the late afternoon. Inspection of APS' hourly load data also indicates that the highest peak loads occur on weekdays.

Q. UNDER WHAT CIRCUMSTANCES WOULD APS' PROPOSED ET-SP RATE BE ATTRACTIVE TO POTENTIAL PARTICIPANTS?

A. For customers to find the rate attractive, it should be simple enough for the average residential customer to understand, and be likely to reduce a participant's bills if he or she reduces super peak and on-peak energy consumption. Tools available to assist customers

to plan, implement, and measure results would include the standard programmable thermostat, as well as required AMI equipment.

Q. IS THE SPECIFIC SUPER PEAK RATE FOR ET-SP CUSTOMERS LIKELY TO BE ATTRACTIVE TO RESIDENTIAL CUSTOMERS?

A. Obviously, customers will have to decide for themselves whether ET-SP is attractive. APS will be able to draw conclusions based on actual experience with customer subscriptions. During the peak summer months (June-August), the ability of a customer to reduce his or her bill depends on how much energy consumption can be shifted from super peak hours to other hours. The best opportunity to achieve savings comes from shifting energy usage from super peak hours to off-peak hours. WRA calculated potential bill savings attributable to rate schedule ET-SP for several patterns of electricity consumption and found that some customers who would otherwise be served under rate schedule ET-2 (as proposed) may be able to save about 1% to 3% on their annual bills ($20 to $60 savings per year). However, some customers might be reluctant to take service under rate schedule ET-SP due to the risk of higher bills if they do not reduce super-peak consumption sufficiently, and due to the relatively small savings if they are able to shift usage away from super peak hours.

Clearly, we do not yet have the last word on the efficacy of APS' proposed rate design. In its response to WRA Data Request 1.16, APS indicates that it has not yet estimated the specific load shifting applicable to rate ET-SP. APS also indicated that it intends to perform a specific load response estimate for Schedule ET-SP if the rate is approved. Such a study is critically necessary and later in my testimony I recommend that the Commission order APS to prepare a study of the impacts of its demand response programs.

VI. APS PROPOSED CPP-GS RATE

Q. WHAT IS CRITICAL PEAK PRICING?

A. Critical Peak Pricing (CPP) is a time-of-use rate that also provides a very high price during a limited number of hours on critical peak days. Customers are typically notified of the critical peak day up to one day in advance.

Q. PLEASE DESCRIBE APS' PROPOSED CRITICAL PEAK PRICING RATE.

A. Under the proposed CPP-GS rate, eligible general service customers would pay a high price for energy use during critical hours as called by the Company with one day's notice. Critical hours would be limited to 90 hours per year, 5 hours per day, and 18 hours per year, only on weekdays from June through September. To make the rate attractive to commercial and industrial customers, discounts would be available for all kWh usage during the period from June through September, as indicated in Exhibit CTS – 2.

Q. WHAT INFERENCES DO YOU DRAW FROM THE LITERATURE ON THE POTENTIAL EFFECTIVNESS OF APS' CRITICAL PEAK PRICING PROGRAM?

A. Based on the experience in other jurisdictions, I expect that APS' critical peak pricing program would shift significant load away from critical peak hours. But, in general, I would expect the critical peak pricing program, by itself, to save little or no energy over the summer overall.

Q. WHAT BENEFITS COULD APS' PROPOSED CPP-GS RATE PROVIDE?

A. In Charles Miessner's prefiled testimony, page 11, lines 3-7, APS indicates that participating customers could reduce their bills, if they reduce usage during critical hours, since they would avoid paying the critical peak price, and would receive a monthly discount on all usage. If the critical peak pricing pilot is successful, APS would be able to avoid or defer generating capacity additions and avoid expensive fuel or purchased power costs during peak periods, thereby lowering its costs and eventually lowering rates.

Q. WHY IS APS RESTRICTING PARTICIPATION IN THE CPP-GS PILOT?

A. APS indicates that since the rate concept is new to APS and relatively new to the industry, and that since there has been little or no experience with critical peak pricing programs on a large scale basis, APS intends to limit participation initially to allow it to assess uncertainties and test the viability of the pilot.

Q. WHAT WOULD HAPPEN IF MORE THAN THE ALLOWED MAXIMUM NUMBER OF CUSTOMERS WANTED TO PARTICIPATE?

A. APS has proposed that it be able to expand participation at its discretion, with notification to the Commission. I believe this is a reasonable approach, and that limiting the number of customers has several advantages: 1) APS limits revenue losses and other risks due to unknown events, and 2) adverse environmental impacts (if any) would be limited.

VII. POTENTIAL IMPACT OF PROPOSED ET-SP AND CPP-GS RATES ON OVERALL ENERGY CONSUMPTION

Q. WHAT DOES EXPERIENCE ELSEWHERE INDICATE ABOUT THE IMPACT OF DEMAND RESPONSE PROGRAMS ON OVERALL ENERGY USAGE?

A. The California pilot results reported in 2005 by Charles River Associates, item R-6 in Exhibit CTS-3, indicated that the critical peak pricing tariff did not have a measurable effect on overall energy use of participants. This would suggest that in the California study, demand response rates may have achieved peak load reductions, but did not result in lowering overall energy use.

Q. ARE ENERGY EFFICIENCY AND DEMAND RESPONSE RELATED?

A. Energy Efficiency programs and Demand Response programs are both considered to be components of Demand Side-Management, as described in David Pickles' prefiled testimony, page 2, line 24. But, as mentioned previously, ACEEE found almost no

published research on the issue of how demand response programs affect energy use during off-peak periods, and on overall building/facility use and energy efficiency.

Q. WHY AREN'T DEMAND RESPONSE PROGRAM RESULTS MEASURED IN THE SAME MANNER AS ENERGY EFFICIENCY PROGRAMS?

A. Demand Response programs are focused on reducing customer demand during times of system reliability concerns or high fuel and purchased power costs. Energy efficiency programs target reductions in overall energy use – not just during peak periods. Both programs measure effectiveness of their intended results, although both have the potential to provide additional benefits.

Q. WHAT DOES ACEEE SUGGEST ABOUT THE RELATIONSHIP BETWEEN ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS?

A. ACEEE indicates that understanding the relationship between the two types of programs is vitally important, as there may be potential synergies, as well as potential conflicts between them.

Q. WHAT POTENTIAL SYNERGIES EXIST BETWEEN ENERGY EFFICIENCY AND DEMAND RESPONSE?

A. ACEEE found the following:

- Pursuing energy efficiency and demand response together creates an opportunity to reduce demand permanently, at peak as well as non-peak times
- Identifying peak-demand reduction opportunities can help identify inefficient and nonessential energy usage that could be reduced at other times
- Technologies that enable demand response can also be used effectively to manage energy use year-round
- Experience from demand response activities can lead to greater awareness of energy savings opportunities through improved energy efficiency

- Customers that participate in demand response programs may be prime candidates for participating in other types of demand side management programs, such as energy efficiency programs
- Program marketing could be more effective at communicating with customers about their energy use by addressing integrated approaches to energy management, and
- Participating in a demand response program, particularly one that features monitoring and control equipment, helps customers better understand their energy use and associated costs, and that process may help encourage additional actions to reduce energy use and costs.[5]

Q. WHAT DOES ACEEE SUGGEST ABOUT DESIGNING SYSTEMS TO TARGET BOTH DEMAND RESPONSE AND ENERGY EFFICIENCY?

A. ACEEE believes that programs can be designed to target both demand response and energy efficiency by promoting technologies that work to achieve both goals. Also, with coordinated program designs across programs, customers can benefit from integrated solutions to their needs.[6]

Q. WHAT DOES ACEEE RECOMMEND TO PROMOTE EFFECTIVE ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS?

A. ACEEE makes two major recommendations for policymakers, regulators, and researchers interested in furthering effective demand-side policies and programs: 1) give a high priority to research on the effects of demand response programs on overall energy usage;

---

[5] American Council for an Energy Efficient Economy, *Exploring the Relationship Between Demand Response and Energy Efficiency: A Review of Experience and Discussion of Key Issues*, March 2005, p. vi.
[6] American Council for an Energy Efficient Economy, *Exploring the Relationship Between Demand Response and Energy Efficiency: A Review of Experience and Discussion of Key Issues*, March 2005, p. vi – vii.

and 2) give a high priority to designing and testing programs that explicitly combine demand response and energy efficiency objectives.[7]

VIII. ENVIRONMENTAL EFFECTS OF PROPOSED ET-SP AND CPP-GS RATES

Q. WHAT ENVIRONMENTAL BENEFITS DOES APS SUGGEST WILL BE PROVIDED BY ITS PROPOSED ET-SP AND CPP- GS RATES?

A. APS does not indicate that its proposed ET-SP and CPP- GS rates were expected to provide any environmental benefits.

Q. CONVERSELY, DOES APS HAVE ANY STUDIES TO SUGGEST THAT SHIFTS OF CUSTOMER LOAD FROM PEAK PERIODS COULD RESULT IN A CHANGE IN CARBON DIOXIDE EMISSIONS?

A. No. In its response to WRA Data Request 1.16, APS indicates that it has not prepared any studies to definitively quantify potential environmental impacts. However, the US EPA study completed in July 2006, item R-4 in Exhibit CTS-3, suggests two scenarios where demand response programs could affect emissions, either of which could occur at APS:

- Scenario 1: On-peak generation is cleaner than off-peak generation – on-peak generation uses natural gas with relatively low emissions while off-peak generation uses coal with relatively high emissions. Load shifting in this case increases emissions, even though total kWh output remains the same.
- Scenario 2: On-peak generation is dirtier than off-peak generation. Suppose the last dispatched on-peak generation unit is a combustion turbine with relatively high emissions and the last dispatched off-peak generation unit is a new combined

[7] American Council for an Energy Efficient Economy, *Exploring the Relationship Between Demand Response and Energy Efficiency: A Review of Experience and Discussion of Key Issues*, March 2005, p. v.

cycle gas turbine with relatively low emissions. Load shifting in this case reduces emissions even though total kWh output remains the same.[8]

Q. HOW COULD SHIFTS FROM PEAK PERIODS TO OFF-PEAK PERIODS HARM THE ENVIRONMENT?

A. If enough load were shifted from on-peak to off-peak periods, and the generation sources utilized during off-peak periods had greater air emissions such as sulfur dioxide, nitrogen oxides, carbon dioxide, particulate matter, or mercury, there could be detrimental impacts on the environment. In its response to WRA data request 1.16, APS indicated that: 1) natural gas-fired combustion turbines are typically the marginal generating units during super peak hours, 2) during other on-peak hours and summer off-peak hours, natural gas-fired combined cycle units are APS' marginal plants, 3) during non-summer months, natural gas-fired combined cycle units are on the margin during on-peak hours, and 4) during non-summer off-peak periods, coal units and natural gas-fired combined cycle units are APS' marginal units. A summary of Arizona power plant emissions is included in Exhibit CTS – 7, which indicates that gas-fired generation is cleaner than coal-fired generation. At this time, we do not have conclusive information on the environmental effects of APS' proposed demand response programs.

Q. HOW CAN THE COMMISSION GET BETTER INFORMATION ON THE ENVIRONMENTAL IMPACTS OF APS' DEMAND RESPONSE PROGRAMS?

A. It will be necessary for APS to analyze any shifts in electricity usage attributable to participation in the demand response programs in order to provide better information on the environmental impact of APS' demand response proposals. This could be done by comparing participant consumption patterns before and after enrollment in a demand response program, taking into account other factors affecting changes in electricity use,

[8] Energy and Environmental Economics, *A Survey of Time-of-Use Pricing and Demand Response Programs*, July 2006, p. 27.

such as weather differences, for example. Then APS would have to determine how those changes in usage patterns affected its generation mix. Lastly, APS would have to calculate air emissions changes associated with the changes in generation mix.

Q. HOW SHOULD THE COMMISSION EVALUATE THE ENVIRONMENTAL IMPACTS OF APS' DEMAND RESPONSE PROGRAMS?

A. Later in my testimony I provide a recommendation regarding the Commission's review of APS' demand response programs.

IX. OTHER ANTICIPATED BENEFITS OF DEMAND RESPONSE RATES

Q. WHAT BENEFITS ARE AVAILABLE TO UTILITIES THROUGH ADOPTION OF ADVANCED METERING TECHNOLOGY?

A. In addition to supporting demand-response programs that better reflect marginal costs and reduce peak energy use to improve system reliability, Southern California Edison indicates that advanced metering technology enables utilities to manage their electricity supply in response to real-time information, and to provide consumers with more detailed use data and improved price signals. Utilities use the data from advanced metering systems to perform more accurate load forecasting, reduce spot market purchases (or sell more power to the wholesale grid), minimize energy imbalances, reduce energy waste, and improve system reliability. Utilities can also shave peak use, reducing their costs and the need for new power plants and transmission lines.[9] Advanced metering technology can also reduce labor costs associated with manual meter reading and provide instant information on power quality and outage detection, allowing for faster response and restoration of service.[10] In addition to these benefits, which should result in lower utility

[9] EPA Clean Energy-Environmental Technical Forum, *Motivating Energy Efficiency with Metering Technologies*, January 22, 2008.
[10] EPA Clean Energy-Environment Technical Forum, *Motivating Energy Efficiency with Metering Technologies*, January 22, 2008.

costs, and ultimately lower utility rates, significant customer benefits are also expected from use of advanced metering technology.

Q. WHAT ADDITIONAL BENEFITS ARE AVAILABLE TO CUSTOMERS THROUGH ADOPTION OF ADVANCED METERING TECHNOLOGY?

A. With advanced metering, commercial and industrial consumers can see their energy use and energy costs in real time, allowing them to make more informed decisions about their overall energy use, and potentially diagnose solutions to equipment problems. Also, all consumers would be able to use the data to benchmark their energy use before and after the installation of energy- efficient measures such as efficient lighting technologies.

X. RECOMMENDATIONS

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE MARKETING OF THE SUPER PEAK AND CRITICAL PEAK PRICING PROGRAMS?

A. Yes. The demand response programs should be offered and marketed jointly with energy efficiency programs to increase the chance that participants in the CPP-GS and ET-SP programs also save energy. By offering the demand response and energy efficiency programs together, APS will increase the benefits of its demand side management activities for both itself and its customers.

Q. DO YOU RECOMMEND APS COMPLETE ANY FURTHER STUDIES APPLICABLE TO RATES ET-SP AND CPP-GS?

A. I recommend that APS prepare a study on the impacts of rate schedules ET-SP and CPP-GS on the mix of power generation sources, and determine whether more coal-fired generation is used as a result of these rates. The study should include estimates of impacts of the new rate schedules on air emissions including carbon dioxide, sulfur

dioxide, nitrogen oxides, particulate matter, and mercury, as I described above. I also recommend that APS analyze the impacts of rate schedules ET-SP and CPP-GS on overall energy usage for participants and identify methods to better integrate its demand response and energy efficiency programs. Further, APS' study should analyze the benefits of the demand response rates, taking into account avoided or deferred generating capacity costs and fuel and other variable cost savings. These studies should be filed in Docket Control within two years of the Commission's decision in this docket.

Q. WHAT SHOULD THE COMMISSION DO WITH THESE STUDIES?

A. Within three months of APS' filing of the studies described above (or in APS' next rate case filing if that rate case is filed prior to the three month deadline), the Commission should consider the environmental impacts of the demand response programs as well as any benefits from these programs and decide whether to continue the demand response programs, modify them, freeze enrollment, or terminate the programs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit CTS-1
Docket No. E-01345A-08-0172

RED MOUNTAIN
ENERGY PARTNERS

Carolyn T. Stewart

Carolyn Stewart
Partner
Red Mountain Energy Partners/
Red Mountain Tribal Energy

2122 E. Highland Avenue, Suite 260
Phoenix, AZ 85016
Tel. 602.516.7540

Professional History

- Red Mountain Energy Partners/Red Mountain Tribal Energy, 2005 to present
- Navigant Consulting, Inc., 1997 to 2005
- Nicor Gas and Nicor Inc. 1975 - 1997
  - Director Communications, Market Intelligence, and Planning
  - Director, Governmental Relations
  - Assistance Secretary and Director Investor Relations
  - Manager, Construction/Maintenance

Education

- Master of Business Administration, University of Chicago
- Bachelor of Science, Finance, University of Illinois

Carolyn Stewart, Partner, Red Mountain Energy Partners, brings more than twenty-five years of energy industry and consulting experience in conventional and renewable energy development, gas distribution and electric distribution operations, regulatory, corporate and business strategy, stakeholder communications, corporate governance, and gas distribution and electric distribution operations. She has represented numerous investor-owned and municipal utilities, independent renewable and conventional power developers and producers, and Indian Tribes. Today, Carolyn focuses on renewable energy feasibility and development, and is supporting energy project development efforts for both wind and solar projects, primarily in the Southwest. Prior to co-founding Red Mountain, Carolyn headed Navigant Consulting, Inc.'s energy activities in Phoenix. Previously, she held various financial, management and operating positions at Nicor Gas over a 20+ year career. She has considerable knowledge of Southwest utilities, transmission systems, and generation resources, as well as state and federal renewable requirements and incentives.

Professional Engagements

Renewable Energy
Solar

» Coordinate energy project development support activities for a 3 MW solar project in New Mexico, including site control, project structure, interconnection studies, power purchase negotiations and financing. The project structure utilizes multiple tax credits, accelerated depreciation benefits, and ownership flip structures.

» Coordinated feasibility studies for solar projects in the Southwest, including Concentrating Photovoltaic, Concentrating Solar Thermal and Photovoltaic technologies, ranging from 3 MW to 100+ MW.

Wind

» Manage feasibility studies for multiple wind projects in Northeast Nebraska, to serve facility and community loads, as well to meet utility-scale power needs.

» Coordinate energy project development partner outreach efforts for a proposed 40 - 80 MW wind project in North Central Oklahoma.

Natural Gas

» Coordinated support efforts in development and permitting of a gas-fired independent power plant in the Southwest, utilizing natural gas and parabolic trough technologies. Provided expert testimony on natural gas supply and transportation issues.

Biomass

» Supported biomass project development activities and bid development for an independent renewable developer in the Southwest.

» Managed multiple studies for the Pueblo of Laguna on comprehensive Utility Authority formation and development. Coordinated grant application development to fund project implementation.

Tribal Utility Operations/Formation

» Support studies associated with development of a comprehensive utility organization for a Southern California Indian Tribe, including water, wastewater, and solar power generation activities.

» Managed implementation of Pueblo of Laguna Utility Authority administrative and utility operations activities, including interim onsite utility management and General Manager recruitment.

» Coordinated NCI support in its assignment as interim general manager of the Aha Macav Power Service, the Tribally-owned electric and natural gas utility serving the Fort Mohave Indian Tribe in Arizona, Nevada and California. Recruited a new general manager to lead the utility and provided consulting support during the transition period.

Other (NCI)

» Provided support for the U.S. Navy, as part of their Navy Utility Privatization effort, in the development of contracts and in negotiations with bidders for natural gas properties.

» Coordinated ongoing oversight of precedent-setting Federal Trade Commission-directed easement agreement between a Midwest natural gas utility and wholesale/retail energy merchant to ensure competitive conditions in a gas/electric merger.

» Supported a Midwest gas & electric utility's efforts to prepare filings in support of its customer choice program. Coordinated rate design and terms and conditions modifications for a new small commercial customer class.

» Coordinated NCI support efforts on behalf of a Canadian gas & electric Crown Corporation working to influence the integration of its LDC acquisition, specifically as related to the company's efforts to provide additional regulated gas supply offerings.

» Managed development and implementation of service and rate unbundling strategies for a Midwest municipal gas utility. Coordinated all aspects of comprehensive regulatory filing and choice program development, including case strategy, expert testimony development, development of new tariff and terms and conditions, external benchmarking, internal capability assessments, information system evaluations and stakeholder communication plans and implementation.

- Assisted an internal executive strategic planning team of an Eastern gas & electric utility in its consideration of implications, across all utility functions, of exiting the gas merchant function.

- For an Asian electric utility, reviewed all aspects of electric regulation reform and restructuring activities in six countries, and two US cities, covering the restructuring process, existing market structure and status, pricing determination and objectives, and implications for the client.

- Supported deregulation issues management for a Midwestern gas & electric utility with respect to retail choice, federal restructuring legislation, customer service standards, and public benefits.

- Supported negotiations for gas delivery service between a Canadian gas utility and gas-fired generation plants, focusing on components of typical contractual arrangements.

- Assisted a Western Pipeline Shipper Organization in providing support in response to FERC complaint involving proposed capacity allocation requirements.

- Assisted a Midwestern gas utility in development of research focused on hedging and risk management tactics.

- Assessed merger/acquisition and alliance partner candidates for a Midwest energy company.

- Developed and implemented corporate and business unit strategic and business planning processes, plans and communications for a Midwest energy company.

- Established new business development evaluation process and team and assessed new business opportunities, including domestic and international investments for a Midwest energy company.

- Coordinated retail energy marketing studies, including evaluation of alliance and partner candidates, and market research to validate product and service offerings for a Midwest energy company.

Expert Testimony

- Testified before the Arizona Power Plant and Transmission Line Siting Committee. Wellton-Mohawk Generating Facility, Docket No. L-00000Z-01-0114; Case No. 114. (2003)

- Testified before the Arizona Corporation Commission. Wellton-Mohawk Generating Facility (2005)

RATE SCHEDULE ET-SP
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE SUPER PEAK 7PM-NOON

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Additionally, this rate requires the Customer to have an Advanced Metering Infastructure meter, or AMI, in place at time of service.

APPLICATION

This rate schedule is applicable to all Standard Offer electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.509 per day

Energy Charge:

June – August Billing Cycles (Super Peak Summer)
$0.49465 per kWh during Super-Peak hours, plus $0.24465 per kWh during On-Peak hours, plus $0.05259 per kWh during Off-Peak hours

May, September, and October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.24465 per kWh during On-Peak hours, plus $0.05259 per kWh during Off-Peak hours	$0.19842 per kWh during On-Peak hours, plus $0.05259 per kWh during Off-Peak hours

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$ 0.227	per day
Revenue Cycle Service Charges:		
Metering	$ 0.165	per day
Meter Reading	$ 0.055	per day
Billing	$ 0.062	per day
System Benefits Charge:	$ 0.00188	per kWh
Delivery Charge:	$ 0.02222	per kWh

Generation Charge:

June – August Billing Cycles (Super Peak Summer)
$0.47055 per kWh during Super-Peak hours, plus $0.22055 per kWh during On-Peak hours, plus $0.02849 per kWh during Off-Peak hours

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.22055 per kWh during On-Peak hours, plus $0.02849 per kWh during Off-Peak hours	$0.17432 per kWh during On-Peak hours, plus $0.02849 per kWh during Off-Peak hours

TIME PERIODS

The Super-Peak time period is 3 p.m. to 6 p.m. and the On-Peak time period is 12 noon to 3 p.m. and 6pm to 7pm, during the Super Peak Summer months Monday through Friday excluding the holidays listed below. The On-Peak time period during Summer and Winter months for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the Super-Peak or On-Peak time periods shall be Off-Peak hours for all seasons.

The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period. Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule RES pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

4. The bill is subject to the Environmental Improvement Surcharge as set forth in the Company's Adjustment Schedule EIS pursuant to Arizona Corporation Commission Decision No. XXXXX.

5. The bill is subject to the Competition Rules Compliance Charge as set forth in the Company's Adjustment Schedule CRCC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

6. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

7. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

8. The bill is subject to the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of APS and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE CPP-GS
CRITICAL PEAK PRICING – GENERAL SERVICE

AVAILABILITY

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

APPLICATION

The Rate Schedule CPP-GS is available to retail Standard Offer customers served on Rate Schedules E-32 M, E-32 L, E-32TOU M, E-32TOU L, E-34, E-35, and E-221. The eligible customer must demonstrate the ability to reduce usage during Critical Events by a minimum of 200 kW and submit a load reduction plan, which must be approved by the Company prior to participation. The eligible customer must also have interval metering. All provisions of the Customer's otherwise applicable rate schedule will apply in addition to the charges in Schedule CPP-GS. Partcipation is limited to the first 100 customers for a period of two years from the initial availability. The Company may expand eligibility during this two-year period, at its discretion, upon notification to the Commisison.

RATES

A. Critical Peak Price	$0.40000	per kWh
Critical Peak Price applies to kWh usage during a CPP Event.		
B. Energy Discount		
Rate Schedule E-32 M (401-999 kW)	$(0.014892)	per kWh
Rate Schedule E-32 L (1000+ kW)	$(0.014438)	per kWh
Rate Schedule E-32 TOU M (401-999 kW)	$(0.014892)	per kWh
Rate Schedule E-32 TOU L (1000+ kW)	$(0.014438)	per kWh
Rate Schedule E-34	$(0.014350)	per kWh
Rate Schedule E-35	$(0.012470)	per kWh
Rate Schedule E-221	$(0.011755)	per kWh
Energy Discount applies to Customer's total monthly kWh.		

CONDITIONS

A. CPP Events: CPP Events may be invoked by the Company for the period 2 p.m. to 7 p.m., weekdays (Monday through Friday) during June through September. Holidays are excluded, which include Independence Day (July 4th) and Labor Day (first Monday in September). A CPP Event can be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage, as determined by the Company.

B. Number and Duration of CPP Events: The Company may invoke a maximum of 18 CPP Events per calendar year, for 5 hours per event and 90 hours per year.

C. CPP Event Notification/Communication: Customers would be notified of a CPP Event in advance by 4:00 PM the day prior through a phone message and e-mail. Receipt of such notice is the responsibility of the participating customer.

D. CPP Event Cancellation: Once a CPP event alert has been initiated, there are no conditions that would warrant the critical event to be cancelled.

Exhibit CTS-3
Docket No. E-01345A-08-0172

Summary of Demand Response Presentations and Reports Reviewed

Presentations

Reference Number	Date	Presentation Title	Audience	Presenting Firm	Presenters	Primary Content
P-1	June 18, 2008	Evaluating Alternative Pricing Designs	CRRI Western Conference	The Brattle Group	R. Hledik A. Faruqui	Identified range of impacts of dynamic pricing programs
P-2	March 25, 2008	Dynamic Pricing – Potential and Issues	Kansas Corporation Workshop on Energy Efficiency	The Brattle Group	J. Wharton A. Faruqui	Potential impact of dynamic pricing on peak demand; value of demand response; customer price responsiveness by customer and region; how rate design makes dynamic pricing more attractive to customers
P-3	January 29-30, 2008	Supply and Demand Side (Electricity) Management Strategies	Turkish-American Clean Energy Conference	US DOE	L. Mansueti	US Electric Industry: demand response; peak load pricing strategies; energy efficiency;
P-4	January 22, 2008	EPA Clean Energy Environment Technical Forum: Motivating Energy Efficiency with Metering Technologies				Value of AMI
P-5	March 13, 2006	DOE's EPACT Report to Congress on Demand Response in Electricity Markets	Peak Load Management Association	US DOE	L. Mansueti	Demand Response Program Recommendations
P-6	May 4, 2005	California's Statewide Pricing Pilot: Overview of Key Findings	MADRI Advanced Metering Infrastructure Workshop	Charles River Associates	S. George A. Faruqui	Lessons learned from CA pilot; surprises; implications for AMI
P-6	August 31, 2004	Demand Response Hardware and Tariffs: California's Vision and Reality	ACEE Summer Study	California Energy Commission	A. Rosenfeld K. Herter D. Hungerford M. Jaske P. McAuliffe	Overview of summer 2003 CA pilot results
P-8	2003-4	California Statewide Pricing Pilot				Overview of summer 2003-4 CA pilot results

Exhibit CTS-3
Docket No. E-01345A-08-0172

Reports

Reference Number	Date	Report Title	Sponsor	Preparer	Personnel	Primary Content
R-1	January 2008	Quantifying the Benefits of Dynamic Pricing in the Mass Market	Edison Electric Institute	The Brattle Group	A. Faruqui L. Wood	Methodology for quantifying benefits to customers and utilities of dynamic pricing programs
R-2	May 16, 2007	The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs		The Brattle Group	A. Faruqui R. Hledick S. Newell J. Pfeifenberger	Integration of supply side and demand side approaches in achieving load reduction
R-3	July 2007	Ontario Energy Board Smart Price Pilot Final Report	Ontario Energy Board	IBM		Summary of Ontario 2006-2007 Hydro Ottawa time-based pricing structure pilot
R-4	July 2006	A Survey of Time-of-Use Pricing and Demand-Response Programs	US Environmental Protection Agency	Energy & Environmental Economics		Summary of demand response options in support of energy efficiency goals
R-5	August 2006	Assessment of Demand Response and Advanced Metering	Federal Energy Regulatory Commission	Staff Report		Survey identification of key issues
R-6	March 16, 2005	Impact Evaluation of the California Statewide Pricing Pilot		Charles River Associates		Summarizes the final results of the 2003-4 California statewide pilot
R-7	March 2005	Exploring the Relationship Between Demand Response and Energy Efficiency: A Review of Experience and Discussion of Key Issues	American Council for an Energy-Efficient Economy		D. York M. Kusher	Examine relationship between energy efficiency and demand response
R-8	August 2004	Electricity Markets: Consumers Could Benefit from Demand Programs, but Challenges Remain		US Government Accountability Office		Types of programs in use; benefits indicated; barriers to introduction and expansion; examples of barriers overcome

Exhibit CTS-3
Docket No. E-01345A-08-0172

Reference Number	Date	Report Title	Sponsor	Preparer	Personnel	Primary Content
R-9	August 2004	Does Real Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff	California Energy Commission	Ernest Orlando Lawrence Berkeley National Laboratory; Neenan Associates	C. Goldman N. Hopper O. Sezgen M. Moezzi R. Bharvirkar B. Neenan D. Pratt P. Cappers R. Boisvert	Niagara Mohawk RTP Study of 149 large C&I customers
R-10	June 2004	Customer Response to Day-Ahead Wholesale Market Electricity Prices: Case Study of RTP Program Experience in New York	California Energy Commission	Ernest Orlando Lawrence Berkeley National Laboratory; Neenan Associates	C. Goldman N. Hopper O. Sezgen M. Moezzi R. Bharvirkar B. Neenan D. Pratt P. Cappers R. Boisvert	Niagara Mohawk RTP Study of 149 large C&I customers

Exhibit CTS-4
Docket No. E-01345A-08-0172

Summary of Typical Demand Response Program Effectiveness Measures

Location	Program	Program Type	Measures of Program Effectiveness					Primary Data Source
			Peak Load Reduction	Customer Bill Impacts	Customer Satisfaction	Impact of Technology	Energy Usage	
California	ADRS	CPP	27% - 51%			X		P-2, R-1
	Anaheim	PTR, CPP	12% during CP hours					R-1
	Statewide Pricing Pilot	CPPV	34.5% – 47.4%	-4% to 5.1%	33%	X		P-6 - P-8, R-1
		CPPF	12.5%	-6.0% to 8.3%	45%	X		P-6 - P-8, R-1
		TOU	4.1%	-3.0% to 4.5%	40%	X		P-6 - P-8, R-1
	Pacific Gas & Electric		18%					R-8
	San Diego Gas & Electric	Regional Wholesale Pricing	5%					R-8
Carolinas	Duke Power	RTP	8%					R-8
Florida	Gulf Power	CPP	40% - 50%					P-2, R-1, R-8
Georgia	Georgia Power	RTP	30-60%					R-8
Idaho	Idaho Power	CPP	48%					P-2, R-1
Illinois	Community Energy Cooperative	ESPP		-19.6%			-3% to -4%	R-1, R-5, R-8
Missouri	Ameren	TOU, CPP	13-35%			X		P-2, R-1
New Jersey	PSEG	TOU, CPP	12-18%					P-2, R-1, R-8
New York	Niagara Mohawk	RTP	18%		3.2 (1-5, 5 is highest)	X	X	R-9, R-10

Exhibit CTS-4
Docket No. E-01345A-08-0172

Location	Program	Program Type	Measures of Program Effectiveness					Primary Data Source
			Peak Load Reduction	Customer Bill Impacts	Customer Satisfaction	Impact of Technology	Energy Usage	
Wisconsin	Wisconsin Public Service	TOU	12-31%					R-8
Australia	Energy Australia	CPP	20-24%					P-2, R-1
Ontario, Canada		TOU, CPP, PTR	5.7% – 25.4% load shift CP hours; 2.4% – 11.9% peak hours				-6%	P-2, R-1

Terms Used:

ESPP – Energy Smart Pricing Plan
CPP - Critical Peak Pricing
CPPF – Critical Peak Pricing - Fixed
CPPV – Critical Peak Pricing - Variable
PTR – Peak Time Rebate
RTP – Real Time Pricing
TOU – Time of Use

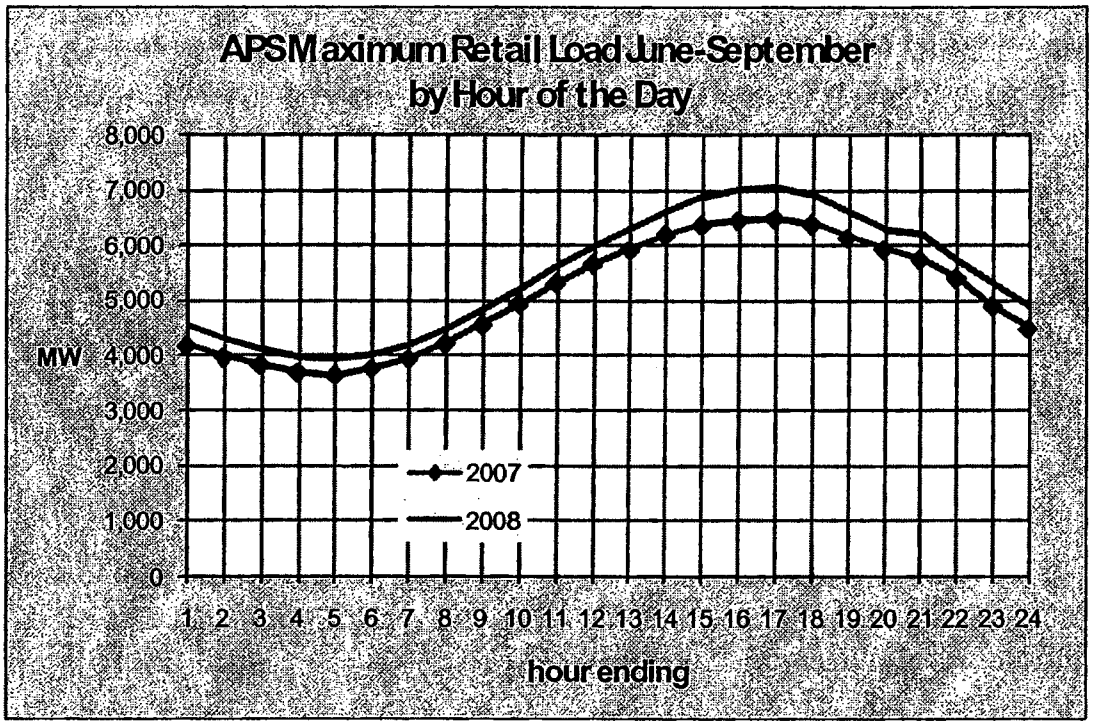
Exhibit CTS-5
Docket No. E-01345A-08-0172

Summary of Proposed Rates ET-SP and ET-2

Rate	Summer $/kWh			Winter $/kWh	
	Super Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
ET-SP	$0.49465	$0.24465	$0.05259	$0.19842	$0.05259
ET-2		$0.24465	$0.06131	$0.19842	$0.06130

Exhibit CTS-6
Docket No. E-01345A-08-0172

APS Maximum Retail Load
June – September 2007 - 2008



Graph shows APS' maximum retail load occurring in each hour during the summer of the year indicated. The peak load for hour n may not occur on the same day as the peak load for hour m. APS' retail peak load in 2008 occurred at 5:00 p.m. on August 1, and APS' retail peak load in 2007 occurred at 5:00 p.m. on August 13.

Source: APS response to Staff data request 22.10.

Exhibit CTS-7
Docket No. E-01345A-08-0172

Arizona Power Plant Air Emissions Rates 2006
Metric Tons per MWh Generated

Generation Type	CO_2 Emissions	SO_2 Emissions	NO_x Emissions
Coal	0.986	0.00110	0.00175
Natural Gas	0.409	0.00000	0.00012

Source: Energy Information Administration

EXHIBIT
WRA-2
ADMITTED

Timothy M. Hogan (004567)
ARIZONA CENTER FOR LAW
IN THE PUBLIC INTEREST
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
(602) 258-8850

Attorneys for Western Resource Advocates

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 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 TESTIMONY OF DAVID BERRY, WESTERN RESOURCE ADVOCATES IN SUPPORT OF SETTLEMENT AGREEMENT**

The Western Resource Advocates ("WRA"), through its undersigned counsel, hereby provides notice that it has this day filed the testimony of David Berry in support of the settlement agreement in connection with the above-captioned matter.

DATED this 1st day of July, 2009.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By _____
Timothy M. Hogan
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
Attorneys for Western Resource Advocates

ORIGINAL and 13 COPIES of
the foregoing filed this 1st day
of July, 2009, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing
electronically transmitted
this 1st day of July, 2009 to:

All Parties of Record

_____

BEFORE THE ARIZONA CORPORATION COMMISSION

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

Testimony in Support of the Settlement Agreement

David Berry

Western Resource Advocates

July 1, 2009

Testimony of David Berry
APS Rate Case Settlement
Docket No. E-01345A-08-0172

Table of Contents

Introduction	1
Renewable Energy	2
Demand Response	6
Matters Raised by Chairman Mayes	7
Recommendations	12

List of Exhibits

Qualifications of David Berry	DB-1
Summary of APS Renewable Resources	DB-2
APS Renewable Resource Mix 2015	DB-3
Approximate Cost of Utility Scale Renewable Energy	DB-4

Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064.

Q. By whom are you employed and in what capacity?

A. I am Senior Policy Advisor for Western Resource Advocates.

Q. Please describe Western Resource Advocates.

A. Founded in 1989, Western Resource Advocates (WRA) is a non-profit environmental law and policy organization dedicated to restoring and protecting the natural environment of the Interior American West. We have developed strategic programs in three areas: water, energy, and lands. We meet our goals in collaboration with other environmental and community groups and by developing solutions that are appropriate to the environmental, economic and cultural framework of the region. Western Resource Advocates has been involved in Arizona utility regulatory issues for about 20 years.

Q. What are your professional qualifications for presenting testimony in this docket?

A. Exhibit DB-1 summarizes my qualifications.

Q. Did you file direct testimony in this case?

A. No. Carolyn Stewart filed direct testimony on behalf of WRA in December 2008, dealing with demand response tariffs.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of WRA and address those portions of the settlement agreement pertaining to renewable energy and demand response. I also provide responses to Chairman Mayes' June 9th questions on these issues.

Q. Did you participate in the settlement discussions?

A. Yes. I participated in nearly all the meetings and worked with other parties to develop specific provisions of the agreement.

Renewable Energy

Q. What role will clean energy resources play in Arizona's future?

A. Clean energy resources are those that emit little or no pollutants into the atmosphere, can be supplied on a sustained basis over the long run, and in some cases, use little or no water to produce electricity. These resources include various renewable energy technologies and energy efficiency. Several recent analyses indicate that renewable energy and energy efficiency could comprise the majority of resources needed to meet the growth in demand for electric energy services over the next 5 to 10 years or longer.[1]

Q. What are the benefits of clean energy resources?

A. These resources have several important benefits:

- Renewable resources typically have fixed or stable costs. These fixed or stable costs provide a hedge against volatile and uncertain fossil fuel prices for natural gas or coal-fired power plants.
- Renewable resources typically have little or no air emissions, unlike conventional power plants that burn fossil fuels. Thus, renewable resources reduce air pollution and consequently reduce the health and environmental impacts of fossil fuel combustion. Moreover, because they emit little or no carbon dioxide, sulfur dioxide, nitrogen oxides, mercury, or particulate matter, renewable resources would not incur the costs of controlling these emissions in contrast to fossil-fueled power plants.
- Cost effective energy efficiency has stable prices, little or no air emissions, and costs less than conventional generation.[2]

Q. What provisions does the agreement contain that advance the role of renewable energy in Arizona?

---

[1] Western Resource Advocates, *A Clean Electric Energy Strategy for Arizona*, Boulder, CO: 2007. Arizona Public Service Company, *Resource Plan Report*, January 29, 2009, filed in Docket No. E-01345A-09-0037.

[2] Other parties, including SWEEP, address energy efficiency aspects of the settlement agreement.

A. The agreement provides that APS obtain about 10% of its **energy needs** from renewable resources by 2015. This is approximately double the Renewable Energy Standard (RES) requirement that 5% of **retail sales** be obtained from renewable resources by 2015.

Under the terms of the settlement, Section XV, APS is to make its best efforts to acquire new renewable energy resources with annual generation or savings of 1,700,000 MWh to be in service by the end of 2015. These new resources are in addition to: (a) resources APS had in place as of the end of 2008, and (b) resources which APS had committed to by the end of 2008. Exhibit DB-2 presents information on existing, committed, and new resources in more detail. Exhibit DB-3 shows the mix of renewable resources APS would have in 2015. The sum of the energy output of the new renewable resources and the existing and committed renewable energy resources is approximately the amount of renewable energy inherent in APS' resource plan for the year 2015.

APS' resource plan proposes a reasonable acceleration of the deployment of renewable resources through 2015 and it is consistent with WRA's analysis of the role of renewable energy in Arizona in the next few years.[3] The settlement agreement obligates APS to implement its resource plan with respect to renewable energy through 2015.

The new renewable resources include both distributed and non-distributed projects. APS is to report to the Commission on its plans for and progress toward acquiring the new renewable energy resources in its Renewable Energy Standard Implementation Plans and Compliance Reports and in future resource planning filings.

The agreement specifies some (not all) of the new resources APS will seek to acquire:

- A utility scale photovoltaic project. Central station photovoltaic projects are being installed worldwide. For example, there are recent projects of 40 MW or larger in Spain, Germany, and Portugal and a 30 MW photovoltaic plant is planned for service starting in 2010 by Tri-State in New Mexico.
- In-state wind energy.[4]
- A solar energy program for on-site projects at grade K through 12 public schools. Projects could include photovoltaics, solar hot water, and day-lighting. The program

[3] In our Clean Energy Strategy report, we proposed that about 10.5% of the state's (not just APS') 2015 energy needs come from renewable energy: Western Resource Advocates, *A Clean Electric Energy Strategy for Arizona*, Boulder, CO: 2007.

[4] There is already one commercial scale wind energy project under construction in Arizona – the 63 MW Dry Lake project which will sell its energy to Salt River Project. According to the *Arizona Republic*, May 12, 2009, the capacity factor at the Dry Lake project would be about 24% which is considerably lower than the typical western wind energy project which has a capacity factor of about 35%. In general, projects with higher capacity factors have lower costs per MWh.

goal is to install projects producing 50,000 MWh per year of energy savings or generation within 36 months of program approval by the Commission. This program will be developed so that up-front customer costs are eliminated, thereby making it easier for schools to participate. APS is to consider a request for proposals by project developers to implement and install solar energy systems on multiple schools.

- A distributed solar energy program for government structures that reduces or eliminates up-front customer costs.

The agreement also indicates that, following submission of the Biennial Transmission Assessment report required by Decision No. 70635, APS will commence planning and permitting for siting one or more new transmission lines or upgrades intended to facilitate delivery of renewable energy to APS and will construct these lines or upgrades after satisfactory permitting and authorizations are obtained.

Q. Has APS announced any other new renewable energy projects since the settlement agreement term sheet was filed on May 4, 2009?

A. Yes. On May 22, 2009, APS announced a purchased power agreement to obtain solar energy for 30 years from the 290 MW Starwood Solar I plant with thermal storage which is expected to be available for service in 2013.

Q. How will the Commission review specific projects planned by APS?

A. In general, APS will either bring specific projects to the Commission for review, including those identified in the settlement agreement, or will include resources in its Renewable Energy Standard implementation plans, filed pursuant to A.A.C. R14-2-1813, that will be reviewed by the Commission. For example, on May 22, 2009, APS filed an application regarding the Starwood Solar project in Docket No. E-01345A-09-0261.

Q. How will APS recover the costs of renewable energy projects?

A. Typically, APS would recover costs through its Renewable Energy Standard (RES) tariff and the Power Supply Adjustor.[5] Transmission costs may be recovered through the Transmission Cost Adjustor.

[5] The current practice is that the RES tariff recovers costs in excess of the market cost of comparable conventional generation and the remainder of the cost is recovered through the Power Supply Adjustor.

Q. What are new central station renewable energy technologies likely to cost?

A. The market prices of central station renewable energy and conventional generation change over time, sometimes rather rapidly. Exhibit DB-4 shows WRA's current estimates of the costs of utility scale central station renewable energy projects obtained under long term purchased power agreements and, for comparison, costs of new conventional generation. The costs of conventional generation are highly dependent on fossil fuel price forecasts and such forecasts have proven to be unreliable in the past. Thus, there is great uncertainty about future conventional generation costs. Also, the Exhibit assumes that complying with greenhouse gas emission regulations will cost $30 per metric ton of carbon dioxide equivalent. In general, wind and geothermal energy are very cost competitive today.

Q. Please provide an overview of the on-site solar energy projects for schools required by the settlement agreement.

A. The solar energy projects could include photovoltaics (PV), solar hot water systems, and daylighting. The energy production or savings for schools contemplated by the settlement agreement is 25% to 30% of APS' nonresidential distributed energy requirement in 2013.

School power needs are greatest in the early afternoon and therefore PV systems could contribute significantly to lowering a school's grid power purchases. According to APS' response to the Arizona School Boards Association First Data Request, a typical high school's maximum load at noon in 2007 was 895 kW. The maximum load occurs at 1:00 or 2:00 p.m. (slightly over 900 kW) in August. The typical elementary school maximum load at noon in 2007 was 292 kW and the peak load was at 2:00 pm (321 kW) in August.[6]

Innovations in financing PV projects for tax exempt non-residential site hosts are resulting in a variety of possible ownership and payment arrangements that eliminate up-front customer costs.[7] One possible arrangement is a service contract (purchased power agreement) where a third party owns the PV system and the site host (a school in this case) buys all the electricity generated over a specified time period. The project developer owns or leases the PV system and operates and maintains the system. The school pays only for electricity actually delivered. The project developer or tax investors retain the project's tax incentives and reflect those tax benefits in the price of the electricity. APS' portion of the cost would be any performance or capacity incentive that lowers the cost of the project to

[6] A large scale PV program has been implemented in the San Jose, CA Unified School District which completed a 5.5 MW solar energy project at 14 district sites: "San Jose Dedicates Largest School District Solar Power Project in U.S." www.pv-tech.org/lib/printable/4621/, February 5, 2009.

[7] Mark Bolinger, *Financing Non-Residential Photovoltaic Projects: Options and Implications*, Lawrence Berkeley National Laboratory, LBNL-1410E, January 2009.

the schools and any administrative costs associated with the schools solar energy program. The settlement agreement allows APS and developers flexibility in designing a program with input from schools and the solar energy industry, and thus does not specify what incentive APS is to offer.

Lastly, the settlement agreement contemplates that Stimulus Funding may be available to help pay for the school solar energy program.

Demand Response

Q. What are demand response programs?

A. The Federal Energy Regulatory Commission (FERC) defines demand response as actions by customers to change their consumption of electric power in response to price signals, incentives, or directions from grid operators.[8] The FERC explains that demand response is typically an active response to prices or incentive payments. Changes in electricity use are short term and centered on critical hours of the day or year when demand is high or system reliability is jeopardized. Demand response programs are intended to reduce customer usage during these critical periods.

Q. What provisions does the settlement agreement include regarding demand response programs?

A. The settlement agreement includes an optional super peak time of use rate for residential customers and optional critical peak pricing programs for residential and nonresidential customers. The super peak pricing program charges a very high rate during the period from 3:00 p.m. to 6:00 p.m. on weekdays from June through August (the super peak period). However, off-peak rates are lower than off-peak rates under residential time of use rate ET-2, so participating customers could save money by shifting load to off-peak hours. With critical peak pricing, APS notifies participating customers of critical events. Critical events may be called for the afternoon and early evening on summer weekdays and would occur as a result of severe weather, high loads, high wholesale prices, or major generation or transmission outages. The number and hours of critical events are limited by the terms of the rate schedules. Energy used during critical events is charged at a very high rate, thereby discouraging customers from using electricity during a critical event. As an incentive to customers to participate in critical peak pricing programs, APS offers a discount to the customer's total monthly kWh during the summer. It is unknown how attractive the

[8] Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering*, Staff Report, Docket AD06-2-000, August 2006, p. 5.

proposed rate designs will be to customers, how much demand will be reduced, and how much energy consumption will shifted to other time periods.

Q. Does the settlement agreement adopt WRA's recommendations on demand response programs?

A. Yes, the agreement adopts Carolyn Stewart's two recommendations. First, the agreement requires that demand response programs be offered and marketed jointly with energy efficiency programs to increase the chance that participants also save energy. By offering the demand response and energy efficiency programs together, APS will increase the benefits of its demand side management activities for both itself and its customers. Second, the agreement requires APS to prepare a study on the impacts of demand response rates on the mix of power generation sources, and to determine whether more coal-fired generation is used as a result of these rates. The study will include estimates of impacts of the new rate schedules on air emissions including carbon dioxide, sulfur dioxide, nitrogen oxides, particulate matter, and mercury. APS is to also analyze the impacts of the demand response rates on overall energy usage for participants and identify methods to better integrate its demand response and energy efficiency programs. Finally, the study will analyze the benefits of the demand response rates, taking into account avoided or deferred generating capacity costs and fuel and other variable cost savings.

Matters Raised by Chairman Mayes

Q. In her letter dated June 9, 2009, Chairman Mayes raised several matters related to renewable energy and energy efficiency. The first matter deals with APS' new utility-scale photovoltaic energy project: whether the solar plant referenced in the term sheet is the Starwood solar project, whether it is one of the other projects identified in APS' resource plan, and whether it goes beyond projects previously identified by the Company. Chairman Mayes also asked why, if the utility scale photovoltaic project is already in APS' resource plan, is it considered a benefit in the settlement agreement? Please respond to Chairman Mayes' questions on this project.

A. This planned utility-scale photovoltaic project is not the Starwood concentrating solar power plant. (See Exhibits DB-2 and 3). APS' resource plan does not identify specific projects but deals with renewable energy additions generically. The utility-scale photovoltaic project is contained within the overall renewable energy target for 2015 incorporated in the resource plan but is not specifically identified in the resource plan.

The benefits of the renewable energy goals in the settlement agreement are that: (1) APS' renewable energy plans through 2015 are reasonable, (2) the agreement commits APS to implement its resource plan with regard to renewable energy through 2015, and (3) the

agreement identifies some specific projects that were characterized generically in the resource plan.

Q. The second matter deals with the time frame for an in-state wind energy project, the process for selecting an in-state wind generation project, and whether the project would be constructed. Please address these issues.

A. The settlement agreement indicates that APS will issue a new request for proposals for in-state wind generation within 90 days of Commission approval of the Agreement. Within 180 days of issuing the RFP, APS will file a request for Commission approval of one or more such projects. I expect that APS would proceed with in-state wind energy projects if the Commission approved the projects. As I noted above, if the projects have relatively low capacity factors, as the Dry Lake project does, then the cost per MWh would be higher.

Q. Chairman Mayes asked whether the Parties believe that it is in the public interest to adopt the RES in this case and whether the Parties would object to the Commission requiring that APS exceed the RES standard in this case by setting a goal of 8.813 million MWh of renewable energy by 2025. What is WRA's position on these matters?

A. Section 15.8 of the settlement agreement indicates that APS supports the current RES and commits to the renewable energy goals inherent in the settlement agreement. We negotiated provisions that exceed RES requirements through 2015. It would very difficult to plan with any precision for years after 2015 at this time and the agreement does not address renewable energy additions after 2015.

As for setting a renewable energy goal for 2025 in excess of the existing RES target, there are two fundamental issues that the Commission must consider. **First** is whether a higher target is in the public interest. WRA supported a higher target in the rulemaking process leading to the RES.[9] A higher target has several benefits, including the following:

- Renewable energy, along with energy efficiency, are the two most important components of the new energy paradigm for serving Arizona consumers over the long run.
- Renewable energy is, in general, stably priced in contrast to fossil-fueled power generation which suffers from considerable uncertainty about future fuel prices.
- Renewable energy has little or no air emissions. Complying with existing and future regulations of carbon dioxide, mercury, sulfur dioxide, and nitrogen oxide

[9] See comments filed in Docket No. RE-00000C-05-0030, February 17, 2005.

emissions from fossil-fueled power plants has large, uncertain costs. Renewable energy will not, in general, incur these costs.

- Particulate matter resulting from coal-fired power production imposes large health costs on the nation, including premature mortality, various respiratory diseases, and heart attacks.

The **second** issue is whether this rate case is the proper forum for setting a higher renewable energy target for 2025. Some stakeholders (for example, renewable energy contractors and developers) are not parties to the current APS rate case and they should have the opportunity to address changes in the renewable energy goals. Additionally, there are many factors that should be carefully weighed in selecting a higher target, whether it is the one proposed by Chairman Mayes or another target. For example, to reduce the impacts of climate change it will be necessary to dramatically reduce carbon dioxide emissions in absolute terms, not just reduce the increase in emissions. Therefore, existing coal-fired power plants will have to be retired and replaced with clean energy resources or the carbon dioxide emissions from existing coal-fired power plants will have to be captured and safely stored. A new renewable energy target, whether established as a new RES or in a resource planning context, should consider retirement of existing coal plants. I believe that the Commission should address a higher target for APS and perhaps other utilities in a separate proceeding where the pertinent factors can be explicitly considered and a solid basis for a new standard can be established.

In sum, in the context of the current rate case, WRA supports the settlement agreement. Beyond the scope of the settlement agreement and this rate case, WRA continues to support the use of renewable energy above the level of the RES target for 2025.

Q. Chairman Mayes also asked whether the 1.7 million MWh of additional renewable energy to be acquired is above and beyond or part of the 400 MW referenced in APS' resource plan and whether the 1.7 million MWh exceeds the Company's announcement, in connection with the Starwood Solar project, that it would achieve nearly double the RES standard by 2015. If the Company's pre-existing plan was to double the RES requirements by adding an additional 1.7 million MWh of renewable energy, should the Commission consider this a benefit to consumers in this case?

A. The 1.7 million MWh of additional renewable energy contemplated by the settlement agreement plus existing and committed renewable resources are consistent with and reflect the level renewable resources shown in APS' load and resources table in its resource plan for 2015. Note that the MW shown in the load and resources table are not nameplate MW, but APS' projection of the capacity credits of a generic mix of renewable resources.

The 1.7 million MWh of additional renewable resources plus existing and committed renewable resources are the means by which the Company would nearly double the RES standard by 2015. The 1.7 million MWh is not on top of the goal of approximately doubling the RES requirement by 2015.

As noted above, the benefits of the renewable energy goals in the settlement agreement are that APS' renewable resource plans through 2015 are reasonable, that the agreement commits APS to carry out its resource plan, with regard to renewable resources, through 2015, and that the agreement identifies some specific projects that were characterized generically in the resource plan.

Q. Chairman Mayes asked the Parties to consider whether it would be in the public interest to require APS to adopt a pilot feed-in tariff to encourage the rapid adoption of solar energy by Arizona business or in areas of the state where APS projects that significant growth will occur. Please comment in this matter.

A. A feed-in tariff is one tool for encouraging renewable energy. Feed-in tariffs are used in Europe and Canada and apply to central station and distributed renewable energy resources. Feed-in tariffs may offer project owners large payments for delivering renewable energy. A feed-in tariff could be targeted toward specific market segments if the Commission's goals for those market segments are not being met using competitive bidding, performance based incentives, other incentives, or other resource acquisition techniques.

A feed-in tariff appears to be similar to APS' current performance based incentives for large distributed energy projects. The current performance incentives depend on the length of the contract (10 to 20 years) and duration of payments – the maximum payments vary from $0.180 per kWh to $0.250 per kWh.

The California Public Utilities Commission has established feed-in tariffs.[10] The three largest California utilities must offer a buy/sell option and an excess sale option. The feed-in tariff applies to projects up to 1.5 MW for the larger utilities and up to 1.0 MW for other utilities. Each utility is allocated a maximum amount of MW of eligible generation capacity subject to the feed-in tariff. The price paid by the utility for renewable energy is based on California's market price referent, adjusted by a time of day factor. Rates are set for a period of 10, 15, or 20 years.

Gainesville Regional Utilities (GRU) in Florida recently implemented a solar feed-in tariff. Among the features of the tariff are the following:

[10] California Public Utilities Commission, Energy Division, Resolution E-4137, February 14, 2008.

- Eligibility is restricted to photovoltaic (PV) projects.
- Standardized 20 year contracts with fixed rates for purchasing kWh from eligible projects are used.
- There are declining payment schedules over time, so that projects starting in, say, 2012, receive a lower payment rate than projects starting in 2009. The payment rate for projects starting in 2009 for building or pavement mounted systems of any size or ground mounted projects less than 25 kW is $0.32 per kWh.
- GRU buys all the PV output.
- GRU retains renewable energy credits and environmental attributes.
- A program cap of 4 MW per year applies.

If the Commission desires to have APS undertake a feed-in tariff pilot program targeted to a specific customer group, I recommend that it order APS to design and propose a pilot with input from interested stakeholders and submit its proposal for Commission review in its July 2010 RES implementation plan.

Q. Chairman Mayes asked whether CWIP for renewable energy projects is considered in the settlement agreement. Is it?

A. Yes. Section 15.7 states that APS will not seek to recover CWIP related to any of the renewable energy projects required in Section 15 of the settlement agreement because APS will be able to recover carrying costs on utility-owned renewable energy projects.

Q. Chairman Mayes asked whether it is in the public interest to require that any monetized benefits associated with banked carbon credits accrue to ratepayers or be utilized to further enhance APS' renewable energy infrastructure. She also asked whether it would be in the public interest to create a carbon trust fund to ensure that ratepayers receive the full benefit associated with carbon credits created by the RES or energy efficiency programs. What is WRA's position on the treatment of carbon credits?

A. The credits resulting from APS' renewable energy projects and energy efficiency programs might be used by APS in several ways.[11] If APS used the credits to meet its own emission reduction obligations, it will avoid the costs of purchasing credits from others or the costs of making physical changes to its resources to comply with carbon dioxide emission limits; savings could be passed on through lower rates than would otherwise occur. If APS sold the credits, assuming the current limitations on doing so were overcome, the revenues could be

[11] A.A.C. R14-2-1804 (E) states that if an affected utility trades or sells environmental pollution reduction credits or any other environmental attributes associated with kWh produced by an eligible renewable energy resource, the affected utility may not apply renewable energy credits derived from those kWh to satisfy the RES requirements.

counted against renewable energy and energy efficiency program costs or other costs as the Commission directs, thereby benefiting ratepayers. If APS retired the credits, it would accelerate emission reductions and benefit ratepayers and society in general through improved environmental conditions. The Commission should evaluate a range of options in another forum before setting a policy on how to best use emission credits associated with the renewable energy and energy efficiency projects.

Q. Chairman Mayes asked how the energy efficiency goals incorporated in the settlement agreement compare to the Parties' recommendations in the energy efficiency workshops. How does the settlement compare with WRA's recommended efficiency goals?

A. WRA proposed efficiency targets of 1.25% of total energy resources to meet retail load for 2011 and 1.5% in 2012 in its proposed rule submitted on May 29, 2009 in Docket Nos. E-00000J-08-0314 and G-00000C-08-0314. These recommendations are the same as in the settlement agreement for those years.

Q. Chairman Mayes asked for comments on whether the same energy efficiency standard that is being considered in the efficiency workshops could be adopted as part of this rate case. What is WRA's view on this matter?

A. The settlement agreement states that if higher efficiency goals are adopted by the Commission for 2010, 2011 or 2012 in another docket, then those higher goals will supersede the goals listed in the settlement agreement, as will any higher performance incentives.

Recommendation

Q. What is your recommendation regarding the settlement agreement?

A. I believe that the agreement is in the public interest. Of particular importance, it specifies actions for advancing renewable energy and energy efficiency and for moving Arizona toward a new energy economy. I recommend that the Commission approve the settlement agreement.

Q. Does this conclude your testimony?

A. Yes

Exhibit DB-1
Qualifications of David Berry

Areas of Expertise

Energy, natural resource, and environmental economics and policy

Experience

Western Resource Advocates (Scottsdale, AZ), Senior Policy Advisor (2001 – present).
Navigant Consulting, Inc. (Phoenix, AZ), Senior Engagement Manager (1997-2001).
Arizona Corporation Commission (Phoenix, AZ), Chief Economist and Chief, Economics and Research (1985 – 1996).
Boston University Department of Urban Affairs and Planning, Lecturer (1981-1985).
Abt Associates, Inc. (Cambridge, MA), Senior Analyst (1979-1985).
University of Illinois Department of Urban and Regional Planning, Visiting Assistant Professor (1977-1979).
University of Pennsylvania Regional Science Department, Lecturer (1974 –1977).
Regional Science Research Institute (Philadelphia, PA), Research Associate (1972-1977).
U.S. Army (1969-1971).

Education

Ph.D. Regional Science, University of Pennsylvania
MA Regional Science, University of Pennsylvania
BA Geography, Syracuse University

Selected Articles & Papers

"Innovation and the Price of Wind Energy in the US," *Energy Policy* (forthcoming).
"The Impact of Energy Efficiency Programs on the Growth of Electricity Sales," *Energy Policy*, vol. 36 (September 2008): 3620-3625.
"Carbon Risk: Decentralized Risk Management Policy in the US Electric Industry," *Local Environment*, vol. 10. no. 3 (June 2005): 299-307.
"Renewable Energy as a Natural Gas Price Hedge: The Case of Wind," *Energy Policy*, vol. 33, no. 6 (April 2005): 799-807.
"The Market for Tradable Renewable Energy Credits," *Ecological Economics*, vol. 42, no. 3 (September 2002): 369-379.
(with Barbara Keene) "Contracting for Power," *Business Economics*, vol. 30 no. 4 (October 1995): 51-54.
(with Kim Clark) "House Characteristics and the Effectiveness of Energy Conservation Measures," *Journal of the American Planning Association*, vol. 61 (Summer 1995) 386-395.
"The Structure of Electric Utility Least Cost Planning," *Journal of Economic Issues*, vol. 26 (September 1992) 769-789.

"U. S. Cogeneration Policy in Transition," *Energy Policy*, vol. 17 (October 1989) 471-484.

"The Geographic Distribution of Governmental Powers: The Case of Regulation," *Professional Geographer*, vol. 39 (1987) 428-437.

(with J. Andrew Stoeckle) "Decentralization of Risk Management: The Case of Drinking Water," *Journal of Environmental Management*, vol. 22 (1986) 373-388.

(with Stephanie Wilson) "Untapped Labor in the Midwest," in Barry Checkoway and Carl Patton, eds., *The Metropolitan Midwest*, Urbana: University of Illinois Press (1985).

"The Impact of Municipal Water Quality Improvements on Household Water Bills," *Water International*, vol. 10 (1985) 146-150.

"Threats to American Cropland: Urbanization and Soil Erosion," in R. Platt and G. Macinko, eds., *Beyond the Urban Fringe*, Minneapolis: University of Minnesota Press (1983).

"Population Redistribution and Conflicts in Land Use: A Midwestern Perspective," in C. Roseman et al. eds., *Population Redistribution in the Midwest*, Ames, Iowa: North Central Regional Center for Rural Development, Iowa State University (1982).

"The Sensitivity of Dairying to Urbanization: A Study of Northeastern Illinois," *Professional Geographer*, vol. 31 (May 1979) 170-179.

(with Susan Rees) "Location Decisions and Urban Revival: The East St. Louis Riverfront," *Geographical Perspectives*, no. 44 (Fall 1979) 15-29.

"Effects of Urbanization on Agricultural Activities," *Growth and Change*, vol. 9 (July 1978) 2-8.

(with Robert E. Coughlin and Thomas Plaut) "Differential Assessment of Real Property as an Incentive to Open Space Preservation and Farmland Retention," *National Tax Journal*, vol. 31 (June 1978) 165-179.

(with Thomas Plaut) "Retaining Agricultural Activities Under Urban Pressures," *Policy Sciences*, vol. 9 (April 1978) 153-178.

(with Gene Steiker) "An Economic Analysis of Transfer of Development Rights," *Natural Resources Journal*, vol. 17 (January 1977) 55-80.

"Preservation of Open Space and the Concept of Value," *American Journal of Economics and Sociology*, vol. 35 (April 1976) 113-124.

(with Gene Steiker) "The Concept of Justice in Regional Planning," *Journal of the American Institute of Planners*, vol. 40 (November 1974) 414-421.

Recent Reports

Investment Risk of New Coal-Fired Power Plants, Western Resource Advocates, 2008.

A Clean Electric Energy Strategy for Arizona, Western Resource Advocates, 2007.

(with others) *Using Natural Gas More Efficiently*, Western Resource Advocates, 2005.

(with John Nielsen, Ron Lehr, Susan Innis, et al.) *A Balanced Energy Plan for the Interior West*, Western Resource Advocates, 2004.

Testimony and Public Comment Before:

Maine Land Use Regulation Commission
Arizona Corporation Commission
New Mexico Public Regulation Commission
Public Utilities Commission of Nevada

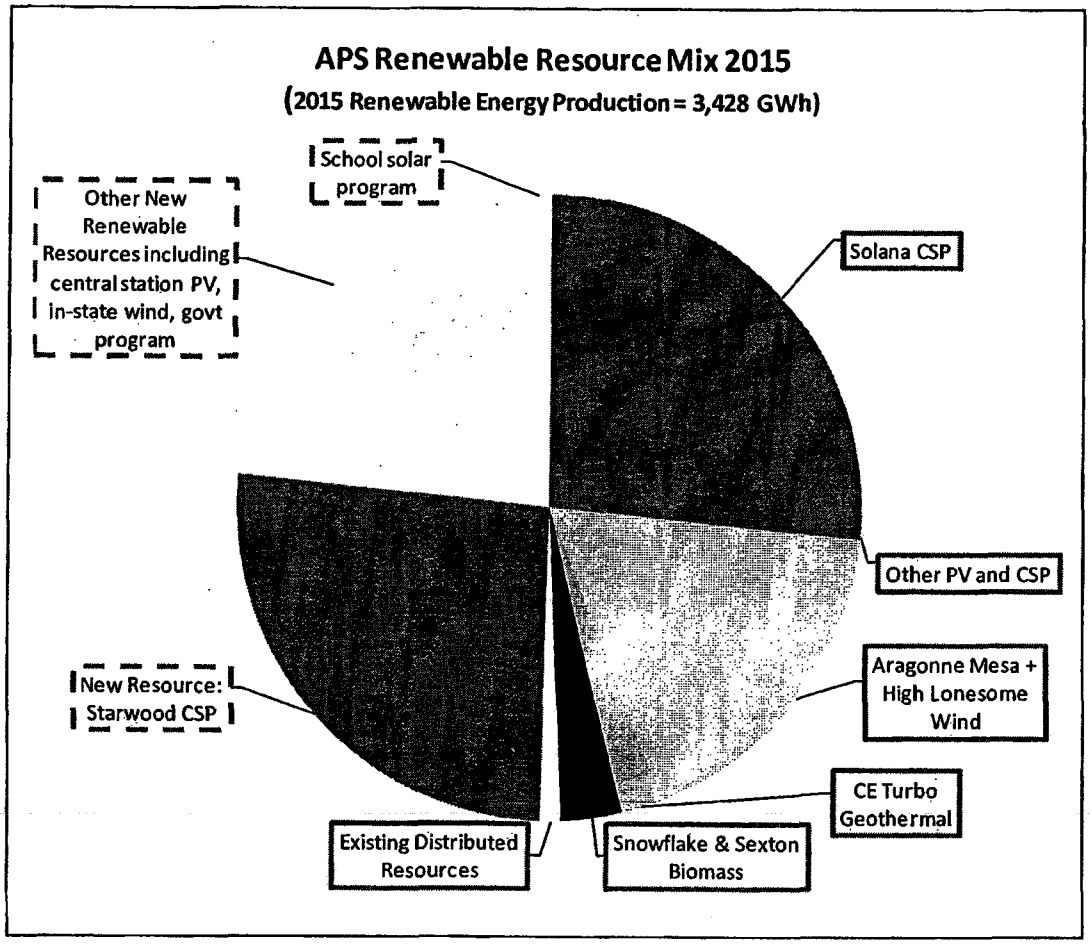
Exhibit DB-2
Summary of APS Renewable Resources

Status	Project/Plans	Start of Service to APS	Annual MWh
Existing and Committed*	Aragonne Mesa Wind	2006	298,455
	High Lonesome Wind	2009	300,000
	CE Turbo Geothermal	2006	71,545
	Snowflake Biomass	2008	86,000
	Sexton Biomass	2009	21,000
	Solana Concentrating Solar Power	2012	903,000
	Other APS owned photovoltaics and concentrating solar power	various	10,243
	Distributed energy	various	37,634
	Subtotal Existing and Committed Projects		**1,727,877**
New	**New Renewable Resources Target in Settlement Agreement includes:** • Starwood Solar I (announced May 22, 2009): ~900,000 MWh per year; on-line in 2013 • Central station PV and wind projects incorporated in settlement agreement • Distributed solar energy projects at schools and government institutions incorporated in settlement agreement • Other projects not yet announced	By 12/31/2015	1,700,000
Total	**Total Annual Renewable Energy**	**By 12/31/2015**	**3,427,877**
	APS Resource Plan Own Load Energy Requirements**	2015	34,996,800

* APS Renewable Energy Standard Annual Compliance Report for the Calendar Year Ending December 31, 2008, filed in Docket No. E-01345A-07-0468, April 1, 2009. Actual 2008 MWh for Aragonne Mesa, CE Turbo, and other APS owned photovoltaics and concentrating solar power, excluding multipliers. Actual annualized 2008 MWh plus reservations for distributed energy, excluding multipliers. Energy production for other projects reflects APS' projected annual production.

** APS Resource Plan Report, Appendix 1, Table 5. These requirements will be met by central station generation, distributed generation, and energy efficiency. Energy requirements include losses.

Exhibit DB-3
APS Renewable Resource Mix 2015



Labels with solid borders indicate existing and committed resources as of December 31, 2008. Labels with dashed borders indicate new resources. CSP = Concentrating Solar Power.

Exhibit DB-4
Approximate Costs of Utility Scale Renewable Energy

Technology	Approximate Cost $/MWh (2009 $)	Comments
Concentrating solar power with thermal storage	$140 to $163	Operational projects in Spain and the US utilize parabolic troughs and central receivers. Some utilize thermal storage. Costs may decrease as more projects are built.
Wind	$51	Wind project costs vary by project capacity factor, wind farm generation capacity, transmission availability, and site specific features. Cost estimate includes $4 per MWh integration cost.
Geothermal	$53	Costs vary according to site specific conditions and type of plant (binary, flash)
Photovoltaics	Project specific	Prices may be falling rapidly as thin film technologies are deployed at large scale plants
Biomass	About $71, but project specific	Numerous types of biomass plants may be deployed – e.g., landfill gas, wood waste, agricultural waste, etc. Costs depend on fuel source and technology.
New natural gas fired combined cycle plant	$111	Cost per MWh is very dependent on fuel prices and capacity factor (assumed to be 35% here). Cost includes an assumed $30 per metric ton cost of complying with carbon dioxide emission regulations.
New conventional coal-fired power plant	$110	Cost includes an assumed $30 per metric ton cost of complying with carbon dioxide emission regulations.

EXHIBIT
WRA-3
ADMITTED

Timothy M. Hogan (004567)
ARIZONA CENTER FOR LAW
IN THE PUBLIC INTEREST
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
(602) 258-8850

Attorneys for Western Resource Advocates

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 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 REVISED EXHIBITS TO THE TESTIMONY OF DAVID BERRY**

Western Resource Advocates ("WRA"), through its undersigned counsel, hereby provides notice that it has this day filed the attached revised exhibits to the testimony of David Berry in support of the Settlement Agreement.

DATED this 17th day of August, 2009.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By _____
Timothy M. Hogan
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
Attorneys for Western Resource Advocates

ORIGINAL and 13 COPIES of
the foregoing filed this 17th day
of August, 2009, with:

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing
electronically transmitted
this 17th day of August, 2009 to:

All Parties of Record

_____

Exhibit DB-2 (Revised)
Summary of APS Renewable Resources

Status	Project/Plans	Start of Service to APS	Annual MWh
Existing and Committed*	Aragonne Mesa Wind	2006	298,455
	High Lonesome Wind	2009	300,000
	CE Turbo Geothermal	2006	71,545
	Snowflake Biomass	2008	86,000
	Sexton Biomass	2009	21,000
	Solana Concentrating Solar Power	2012	903,000
	Other APS owned photovoltaics and concentrating solar power	various	10,243
	Distributed energy	various	37,634
	Subtotal Existing and Committed Projects		**1,727,877**
New	**New Renewable Resources Target in Settlement Agreement includes:** • Starwood Solar I (announced May 22, 2009): ~900,000 MWh per year; on-line in 2013 • Central station PV and wind projects incorporated in settlement agreement • Distributed solar energy projects at schools and government institutions incorporated in settlement agreement • Other projects not yet announced	By 12/31/2015	1,700,000
Total	**Total Annual Renewable Energy**	**By 12/31/2015**	**3,427,877**
	APS Resource Plan Own Load Energy Requirements**	2015	34,996,800

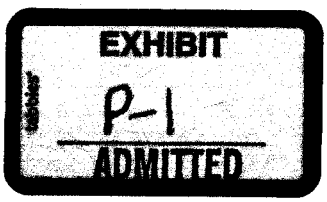
* APS Renewable Energy Standard Annual Compliance Report for the Calendar Year Ending December 31, 2008, filed in Docket No. E-01345A-07-0468, April 1, 2009. Actual 2008 MWh for Aragonne Mesa, CE Turbo, and other APS owned photovoltaics and concentrating solar power, excluding multipliers. Actual annualized 2008 MWh plus reservations for distributed energy, excluding multipliers. Energy production for other projects reflects APS' projected annual production.

** APS Resource Plan Report, Appendix 1, Table 5.

Exhibit DB-4 (Updated August 12, 2009)
Approximate Costs of Utility Scale Renewable Energy

Technology	Approximate Cost $/MWh (2009 $)	Comments
Concentrating solar power with thermal storage	$140 to $163	Operational projects in Spain and the US utilize parabolic troughs and central receivers. Some utilize thermal storage. Costs may decrease as more projects are built.
Wind	$57	Wind project costs vary by project capacity factor, wind farm generation capacity, transmission availability, and site specific features. Cost estimate includes $4 per MWh integration cost.
Geothermal	$58	Costs vary according to site specific conditions and type of plant (binary, flash)
Photovoltaics	Project specific	Prices may be falling rapidly as thin film technologies are deployed at large scale plants
Biomass	About $71, but project specific	Numerous types of biomass plants may be deployed – e.g., landfill gas, wood waste, agricultural waste, etc. Costs depend on fuel source and technology.
New natural gas fired combined cycle plant	$111	Cost per MWh is very dependent on fuel prices and capacity factor (assumed to be 35% here). Cost includes an assumed $30 per metric ton cost of complying with carbon dioxide emission regulations.
New conventional coal-fired power plant	$113	Cost includes an assumed $30 per metric ton cost of complying with carbon dioxide emission regulations.

Testimony of Ian Campbell
In Opposition of Settlement Agreement
Arizona Public Service Company Docket No. E-01345A-08-0172



Q. PLEASE STATE YOUR NAME AND BUSINESS, AND INTEREST IN THIS DOCKET.

A. My name is Ian Campbell and I am a Real Estate Agent that specializes in vacant residential land. The majority of the properties I represent are in the West valley. I am a native of Phoenix and have experienced the incredible urban sprawl first hand. Most of the growth was made possible by flexible and realistic utility policies that allowed for and encouraged utility movement. The new regulations that Arizona Public Service (APS) has imposed on power extensions is causing anti-growth and is having a huge impact on property values that do not have power to the property. As a result, the land market has been adversely affected and this has been unfair to the land owners.

Q. HOW HAS THE POWER POLICY CHANGE AFFECTED YOUR BUSINESS?

A. This power policy change has had a huge impact on my normal business practices. Most of my clients that are wishing to move to the rural areas are doing so to escape the city living problems and live more affordability. Many of them choose the rural living because it affords them a better quality of life and fits into their budgets. This policy change has made the dream land owners have of building a home nothing more than a dream. Most cannot afford the extra cost associated with bringing electrical service to their property.

Q. HOW HAS THE POWER POLICY CHANGE AFFECTED YOUR CLIENTS?

A. I have had numerous clients that have purchased property with intentions of constructing their dream home in the future. They have purchased specific properties with the understanding that APS would extend power to their properties up to 1000 feet without a cost. Today with these policy changes, these same power extensions are going to cost thousands of dollars and most likely will prevent their dream homes from becoming a reality. I do not see how the Arizona Corporation Commission feels that this new policy is in the best interest of the general public.

Q. HOW HAS THE POWER POLICY CHANGE AFFECTED YOU PERSONALLY?

A. I have personally purchased vacant land for investment purposes. My goal has been to split the properties down into smaller parcels to make them more affordable for the enduser. This power policy change has affected the value of my investments greatly. As an example: One of my properties has a power pole located in the Southwest corner of the property. With the old policy I could have the power transformed down and brought onto the property at a reasonable cost. Today the cost thru APS is $7,800. This has a very negative impact on the value of my property and all other properties located within the APS service areas.

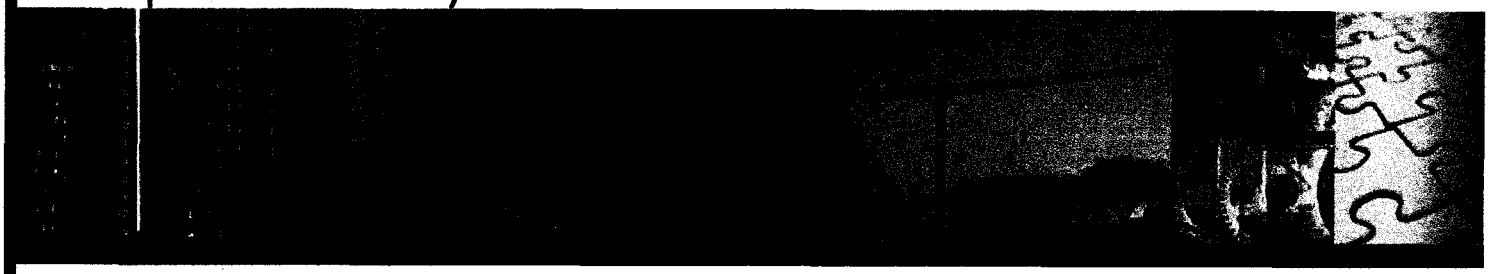
These new changes in the policy have dramatically affected the value of all properties with or without power to the property line. In effect, these new policies will prevent the future movement of power lines and make the majority of rural land almost worthless. This drop in value will lower the tax base and have a tremendous effect on the Arizona economy. I do not feel that this policy is in the best interest of the public or anybody whom has an interest in real estate. Please reconsider these policy changes and be aware of the long term effect of not changing the policy.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT
P-2
ADMITTED

Arizona Utilities - Modifications to Infrastructure Extension Policies Impact Analysis



Prepared for:

Arizonans for Fair Power Policy

July 2009

Prepared by:

Elliott D. Pollack & Company
7505 East 6th Avenue, Suite 100
Scottsdale, Arizona 85251

Table of Contents

Executive Summary **i**

1.0 Introduction **1**
- 1.1 Background 1
- 1.2 Limiting Conditions 2

2.0 Interpretation of Policy Change **4**
- 2.1 Arizona Public Service 4
- 2.2 Tucson Electric Power / UniSource Energy Services 8

3.0 Costs of Extending Electrical Service **10**
- 3.1 Arizona Public Service 10
- 3.2 Tucson Electric Power 15

4.0 Potential Implications of Service Schedule 3 Policy Change **16**
- 4.1 Affected Areas 16
- 4.2 Recent Sales Data 18
- 4.3 Potential Impacts on Property Tax Revenue 19
- 4.4 Interviews Regarding Impact of APS Policy Change 20
- 4.5 Submitted Letters 22
- 4.6 Summary 23

5.0 Economic & Fiscal Impacts of Suppressed Growth **24**
- 5.1 Assumptionsof Analysis 24
- 5.2 Impact of Lost Residential Development Due to Policy Change 26
- 5.3 Fiscal Impact of Residents Occupying New Homes 29
- 5.4 Summary of Impacts 31

6.0 Conclusion **33**

Appendix A – APS Extension Estimates **36**

Executive Summary

Purpose

Elliott D. Pollack & Company was retained by Arizonans for Fair Power Policy to perform a limited impact analysis of the recently modified policies of Arizona Public Service (APS), Tucson Electric Power (TEP) and UniSource Energy Services (UES Electric) to eliminate "no-cost" electrical service extensions to residential lots and subdivisions. The modifications also eliminated related refund schedules and feasibility analyses for commercial developments and residential subdivisions.

Among the changes to the APS service schedule was the elimination of a no-cost extension of electric lines up to 1,000 feet to residential dwellings. The previous no-cost extension was capped at $25,000 with the cost being recouped through existing rates to all customers. The schedule now reads that all costs of extending service, including backbone and infrastructure electrical facilities are to be borne by the applicant (typically a builder or homeowner).

Shortly thereafter, the Arizona Corporation Commission (ACC) approved a proposal by TEP to eliminate free extensions of electrical service lines up to 500 feet to new homes or subdivisions. In addition, the ACC approved the elimination of free service extensions (400 feet of primary, 150 feet of service line and one pole) by UES Electric, which covers much of Mohave and Santa Cruz counties.

APS estimated that the annual construction cost of line extensions for new service was approximately $9 million. Over the last four years, APS estimates that the average cost of extensions have been approximately $9,200 per extension. However, new estimates submitted by APS in recent settlement documents assert that an overhead extension between 500 to 1,000 feet would cost $14,000 to $19,400. By shifting the cost of construction to new customers, the assertion is that rates will decrease, or not increase by as much in the future, for current customers. This also allows for growth to pay for itself.

Potential Effect of Revised Extension Policies

The changes in line extension policies instituted by APS, TEP, and UES could have an impact on residential development and the value of vacant lots and land, primarily in areas where homes are built on large lots and where individual electrical service extensions must be made to a home site. Sales data of recent transactions from individuals with land holdings in the far west part of Greater Phoenix (Tonopah region) have been compiled to assist in the analysis. Most of the land would have been allowed electricity extensions free of cost under the previous APS schedule. Under the new schedule, homeowners will be required to pay for any extensions.

There are many factors that affect the price of land including the availability of water, access to the property, paved and unpaved streets, sewer service or septic tank acceptability, surrounding uses, and similar concerns. One of the most important is electrical service since most homes are not designed to function without the service. With the recent change in electrical extension policies, the cost to extend electrical service to a home site is an issue not previously encountered by prospective homeowners. Without conducting a detailed statistical analysis of land prices in the rural parts of Greater Phoenix, sales data suggests that the distance from electrical service

could be having a negative effect on sales prices. With the added cost to place a home on a lot, at least a portion of the burden to pay for extending electrical service is transferred to the seller of a lot in the form of a lower value.

County assessors are already lowering values on land and homes due to the decline in housing values across Greater Phoenix and Arizona. The main cause of the decline 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 driven land prices down steeply. Based on interviews and letters of submission by various county assessors, the policy changes to eliminate free electrical line extensions means that proximity to existing electrical service lines will likely be correlated with land value.

It is unclear the extent that an 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. It appears, however, that the majority of any impact related to the change in Service Schedule 3 will fall upon the non-urbanized areas and communities of the State rather the more urbanized counties of Maricopa and Pima.

When the cost for an electrical service extension is spread across the typical single family subdivision, the impact is much less per homebuyer if costs are passed forward or buried essentially within all the other infrastructure costs of subdivision development. This is not to imply that the cost is not significant; rather the cost is smaller on a per unit basis. However, for a lot owner in a more rural setting, the cost can be significant. In fact, the cost of an electrical extension may exceed the initial purchase price of the lot. The transition period for instituting the policy change reportedly caught many lot owners and buyers by surprise. In the short term, this means lot values will possibly decline further.

Economic Impact of Revised Service Extension Policies

In the long run, the three affected service areas will likely grow annually by roughly 45,000 customers. That figure may be much less over the next few years as the excess housing stock in the State is absorbed. Extrapolating the four year average of customers qualifying for free extension footage across all service areas yields an estimated 2,340 customers annually that may have qualified for free footage allowances in the past. It is possible that a portion of these customers:

- May not build at all due to higher development costs,
- May not purchase land where an electrical service extension is required,
- May delay construction until a later date,
- May negotiate a price for the property that takes into account a portion, if not all, of the cost of the electrical service extension, or
- May purchase a home where electrical service extensions are already paid for or are not as costly.

Any impact would be more noticeable in the short term as excess quantities of developable land (some already with improvements made) offer competition.

Extensions as a Percent of Customers

	Extensions	APS Customer Growth (Residential)	Extensions % of Residential Growth
2005	1,410	40,188	3.5%
2006	1,935	36,917	5.2%
2007	1,499	21,801	6.9%
2008	687	7,225	9.5%
Total 2005-2008	**5,530**	**106,131**	**5.2%**

Annual Customer Growth (APS, TEP, UNS)[1/]	Extensions % of Growth[2/]	Annual Extensions	Range of Extensions
45,000	**5.2%**	**2,340**	**1,578 - 4,279**

1/ Annual Customer Growth is calculated using the current customer base multiplied by each company's long-term average growth rate. Calculations have been rounded.

2/ Percentage of growth estimated to qualify for free extensions under previous policies. The four year average of qualifying APS customers has been extrapolated over all affected service areas.

Source: Pinnacle West, APS, ASU Construction Reports, Elliott D. Pollack & Co.

For the purpose of this analysis and to illustrate the potential economic and fiscal impacts of lost residential construction, the analysis is conducted in increments of 100 single family homes with an average value of $180,000 per unit (for a total value of homes sold annually of $18 million). The construction cost of each 100 homes would be $10.4 million based on a survey by the National Association of Home Builders. It was assumed that 5% of all homes would be rented. All figures are in 2009 dollars.

Assumptions of Analysis

	Units	Avg.Size per Unit	Value per SF	Value per Unit	Percent Leased	Lease per SF
Low Density Residential	100	1,800	$100	$180,000	5%	$12

Sources: Elliott D. Pollack & Co., MAG, ASU Construction Reports, PMHS.

The following table provides the economic impact of construction for each 100 single family homes built (or not built) in the State of Arizona. The annual economic impact on an individual community could be significant. The economic output (or "value" added) to the community is more than just the construction outlay. Construction activity creates jobs and local spending throughout a community and creates further valuable economic benefits. These benefits take the form of additional business opportunities within a community and additional job opportunities

for area residents. These economic values (also known as direct, indirect, and induced impacts) are quantitatively estimated in this report.

In summary, there could be both economic and fiscal impacts to governmental entities if residential development was indeed stifled by the electrical service extension policy. The economic impact of the construction of 100 single family homes would generate 112 jobs, $5.54 million in wages and $17.81 million in economic output. In terms of potential fiscal impacts, the State of Arizona would collect over $918,000 and the county in which homes would have located would collect approximately $144,000 in revenues. If homes are located within a municipality, the respective city would collect an estimated $250,000 from the construction activity. This represents economic activity and tax revenue that would be lost if 100 homes were not built.

The residents of each 100 homes would generate an additional $76,000, $119,900 and $134,500 each year for the State, the appropriate county and appropriate municipality, respectively, on a cumulative basis. These revenues result from sales taxes from resident spending, property taxes on the homes they occupy and state shared revenues received based on population growth. Thus, for the ongoing resident impact, the estimated fiscal impact would be replicated each year that the home is occupied. Over time, the cumulative impact becomes very significant for the State, counties, and municipalities.

Residential Impact Summary
100 Single Family Homes
(2009 Dollars)

Economic Impact of Constructing 100 Single Family Units	
Jobs	112
Wages ($ mil)	$5.54
Economic Output ($ mil)	$17.81
Fiscal Impact of Construction 100 Single Family Units	
State of Arizona	$918,277
County Level	$143,829
Municipal Level	$249,800
Fiscal Impact of Residents (Annual & Cumulative Annually)	
State of Arizona	$76,038
County Level	$119,918
Municipal Level	$134,543

Source: Elliott D. Pollack & Company; IMPLAN

Conclusion

The policy changes enacted by the ACC have generated reactions from numerous individuals and entities, both public and private. From an economic perspective, the group that will realize the largest impact of these policy changes is landowners whose properties are not currently adjacent to existing electrical lines. To some extent, residential subdivision developers and homebuilders will be affected as well, but the cost of the electrical infrastructure is spread over a larger base of residential homes. Counties and municipalities that see any potential slowdown of residential construction activity due to the electrical service extension policy will also be affected by a slower-growing property tax base. In addition, some non-urban counties of the State are suggesting that the policy could have a much broader impact by affecting land values across their jurisdiction and ultimately their property tax base.

While it is unknown how many homes may not be built due to the increased cost of electrical line extensions, it has been illustrated that 100 homes that are not built will have a significant impact on job creation, economic activity, and governmental revenues, particularly in non-urban communities where the construction of homes on large lots is more the rule than exception.

There is one further factor to consider in the electrical service extension issue. This is the economic theory of "substitution". Very simply, the theory is that as prices rise for a particular good, consumers will substitute away from higher price goods and services to less costly alternatives. This theory will likely come into play in evaluating the impact of the service extension policy on the choices made by potential land buyers and home buyers. Many prospective buyers may actually purchase an alternative home or lot, but not in a location where electric service is a major cost. Counties in Arizona may still see some residential construction activity, but it may be in a different form or location if there are adequate alternatives to substitute for the lots burdened by electrical service extension costs.

The primary impacts of the new service extension policies will fall on two entities:

- Non-urban counties that have a predominance of large lot subdivisions and few, if any, alternative residential areas that will substitute for the expense of electrical service extensions. La Paz, Coconino and Yavapai counties may fall into this category since there are few production builders in the area. As a result, the counties could feel a loss of tax base in addition to the decline in property values due to the current recession.
- Persons who currently own lots in areas not well-served by electrical utilities are likely trapped with their investment or stand to absorb a substantial loss if they sell under the current service extension policies.

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*. The policy will mainly affect a select set of landowners, primarily in rural areas of the State.

1.0 Introduction

Elliott D. Pollack & Company was retained by Arizonans for Fair Power Policy to perform a limited impact analysis of the recently modified policies of Arizona Public Service (APS), Tucson Electric Power (TEP) and UniSource Energy Services (UES Electric) to eliminate "no-cost" electrical service extensions to residential lots and subdivisions. The modifications also eliminated related refund schedules and feasibility analyses for commercial developments and residential subdivisions. The report outlines the opportunity costs of potential lost residential development as a result of the new service extension policies.

1.1 Background

The Arizona Corporation Commission (ACC) recently approved a new service schedule for Arizona Public Service (APS) for residential dwellings (Service Schedule 3). Among the changes to the service schedule was the elimination of a no-cost extension of electric lines up to 1,000 feet to residential dwellings. The previous no-cost extension was capped at $25,000 with the cost being recouped through existing rates to all customers. The schedule now reads that all costs of extending service, including backbone and infrastructure electrical facilities, are to be borne by the applicant (typically a builder or homeowner). However, APS does assert that when it is determined that an extension provides system improvements to the benefit of both APS and other customers, a "system planning cost" is calculated and deducted from the actual cost of the extension.

Shortly thereafter, the ACC approved a proposal by TEP to eliminate free extensions of electrical service lines up to 500 feet to new homes or subdivisions. In addition, the ACC approved the elimination of free service extensions (400 feet of primary, 150 feet of service line and one pole) by UES Electric, which covers much of Mohave and Santa Cruz counties.

APS estimated that the annual construction cost of line extensions for new service was approximately $9 million. Over the last four years, APS estimates that the average cost of extensions have been approximately $9,200 per extension. However, new estimates submitted by APS in recent settlement documents assert that an overhead extension between 500 to 1,000 feet would cost $14,000 to $19,400. By shifting the cost of construction to new customers, the assertion is that rates will decrease, or not increase by as much in the future, for current customers. This also allows for growth to pay for itself.

This study presents a brief interpretation of policy changes that have taken effect. Also, the affected areas of the State have been identified. This firm has interviewed industry experts and reviewed letters submitted to the ACC and a brief synopsis of opinions is provided in a later section of this report. In addition, research was performed to help quantify the cost of extending service under the new policies for various entities (i.e. single lot owners or developers and production homebuilders).

In order to quantify the impact of the new service schedules, this study provides an incremental estimate of the loss of economic activity and revenue resulting from a potential reduction in

residential construction activity. Examples of the economic and fiscal impact of construction and ongoing impacts are provided.

For definitional purposes, economic impact analysis examines the regional implications of an activity in terms of three basic measures: output, earnings and job creation. Fiscal impact analysis evaluates the public revenues and costs created by a particular economic activity. In fiscal impact analysis, the primary revenue sources of a city, county or state government are analyzed to determine how the activity may financially affect them.

1.2 Limiting Conditions

This study prepared by Elliott D. Pollack & Company is subject to the following considerations and limiting conditions:

- It is our understanding that this study is for the client's due diligence and other planning purposes. Neither our report, nor its contents, nor any of our work were intended to be included and, therefore, may not be referred to or quoted in whole or in part, in any registration statement, prospectus, public filing, private offering memorandum, or loan agreement without our prior written approval.

- The reported recommendation(s) represent the considered judgment of Elliott D. Pollack and Company based on the facts, analyses and methodologies described in the report.

- Except as specifically stated to the contrary, this study will not give consideration to the following matters to the extent they exist: (i) matters of a legal nature, including issues of legal title and compliance with federal, state and local laws and ordinances; and (ii) environmental and engineering issues, and the costs associated with their correction. The user of this study will be responsible for making his/her own determination about the impact, if any, of these matters.

- All estimates regarding construction costs were industry averages based on the type of construction. Data has been reviewed and verified to determine its reasonableness and applicability to the analysis.

- This economic and fiscal impact study evaluates the potential "gross impacts" of construction and operations. The term "gross impacts" as used in this study refers to the total revenue, jobs and economic output that could be lost if the new policy indeed hinders economic growth.

- This analysis does not consider the costs to governing entities associated with providing services to a development. Such analysis is beyond the scope of this study. In addition, the analysis is based on the current tax structure and rates imposed by the State, counties, and cities. Changes in those rates would alter the findings of this study. All dollar amounts are stated in constant 2009 dollars and do not take into account the effects of inflation.

- Our analysis is based on currently available information and estimates and assumptions about long-term future development trends. Such estimates and assumptions are subject to uncertainty and variation. Accordingly, we do not represent them as results that will be achieved. Some assumptions inevitably will not materialize and unanticipated events and circumstances may occur; therefore, the actual results achieved may vary materially from the forecasted results. The assumptions disclosed in this impact analysis are those that are believed to be significant to the projections of future results.

2.0 Interpretation of Policy Change

This section will describe the previous and current service extension policies of APS and Tucson Electric Power. Copies of APS Service Schedule 3, both prior and current, are included in the Appendix of this report for reference.

2.1 Arizona Public Service

Portions of the previous APS Service Schedule 3 have been included below, including the no-cost 1,000 foot extension policy, economic feasibility analyses, customer advance caps, and refund policies for customer advances. Excerpts from the new APS Service Schedule 3 are also provided outlining that all costs must be borne by the customer.

Major differences in the in the two service schedules include the discontinuation of economic feasibility studies and the inclusion of a clause stating that any payments made by the customer for new service are non-refundable. Also, construction allowances or refunding mechanisms have been deleted.

Excerpts From Prior APS Service Schedule 3

INTRODUCTION (excerpts)
All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions 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 also as determined by Company.

1. FOOTAGE BASIS – RESIDENTIAL ONLY (excerpts)

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and:

1.2.1 The free extension will be limited to a maximum of 1,000 feet per new permanent residential customer.

1.2.2 Free allowance for the total extension will be 1,000 feet per customer regardless of the customer's location along the route of the extension.

1.3 EXTENSIONS OVER THE FREE DISTANCE

For extensions which meet the conditions specified in Section 1.1 above, and which exceed the free distance specified in Section 1.2.1, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the customer or customers will sign an

extension agreement and advance the cost of such additional footage. Advances are subject to refund as specified in Section 5.

2. REVENUE BASIS - NON-RESIDENTIAL (excerpts)

2.1 GENERAL POLICY - Revenue basis extensions may be made only if all of the following conditions exist:

2.1.1 Applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of $25,000.

2.2 FREE EXTENSIONS - Such extension shall be free to the customer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS - For extensions which meet the conditions specified in Section 2.1, above, and which exceed the free limits specified in Section 2.1.2, Company may extend its facilities up to a cost limitation of $25,000, provided the customer or customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS (excerpts)

3.1 GENERAL POLICY - Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds $25,000 except for extensions specified in Sections 4.4 or 7.7.

3.2 FREE EXTENSIONS

Such extensions shall be free to the customer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less

the cost of service provides an adequate rate of return on the investment made by Company to serve the customer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 3.2, provided such customers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential subdivisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions shall be calculated from information provided by the developer.

Excerpts From New APS Service Schedule 3

INTRODUCTION (excerpts)
All extensions 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 payments received for new or upgraded service under provisions of this schedule shall be non-refundable.

1.0 RESIDENTIAL (excerpts)

1.1 SINGLE FAMILY HOMES

Residential extensions will be made 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. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. Payment is due at the time the extension agreement is executed.

1.2 RESIDENTIAL HOMEBUILDER SUBDIVISIONS

Extensions will be made to residential subdivision developments of four or more homes in advance of application for service by permanent customers provided the applicant(s) signs an extension agreement. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the

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

2.0 NON-RESIDENTIAL (excerpts)

General service line extensions and equipment installations will be made to all applicants not meeting the definition of Residential or as provided for in Section 2.1, or Section 3.0 of this Schedule. All estimated costs of extending service to applicant, as determined by Company, including backbone infrastructure costs, shall be paid by the applicant prior to the Company extending facilities. Payment is due at the time the extension agreement is executed.

5.0 GENERAL CONDITIONS (excerpts)

5.17 POLICY EXCEPTION

The Schedule 3 as stated herein is applicable to all 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 31, 2007. Application of this Section 5.17.1 is limited to Native American Reservations as defined by applicable Federal law.

5.17.2 Existing Line Extension Agreements

All applicants who have executed line extension agreements as of February 27, 2008 will be "grandfathered" into the Schedule 3 in effect at the time the agreement was executed.

5.17.3 Transition Plan

Applicants that have not executed a line extension agreement, will be provided extensions in accordance with the provisions of Service Schedule 3 that was in effect July 1, 2007 through February 26, 2008, if they meet <u>both</u> of the following conditions:

1. Such applicant has received from APS, within six months prior to February 27, 2008, a written estimate of the costs to the applicant for extending service (i.e. received an estimate during the period August 27, 2007 and February 27, 2008); <u>and</u>

2. That same applicant executes a written line extension agreement within twelve (12) months of February 27, 2008 (i.e. no later than February 27, 2009).

Summary

Simply put, the new APS Service Schedule 3 for residential dwellings no longer allows the free extension of electric lines up to 1,000 feet. The schedule now states that all costs of extending service, including backbone and infrastructure electrical facilities are to be borne by the applicant and there appear to be no considerations given to economic feasibility or future refunds of advanced costs. However, APS does assert that when it is determined that an extension provides system improvements to the benefit of both APS and other customers, a "system planning cost" is calculated and deducted from the actual cost of the extension.

The 1,000 foot free extension policy under the old Service Schedule 3 did not apply to residential subdivision or commercial properties. Rather, there was a refund policy to customers who advanced electrical constructions costs and later had permanent residents utilize the extension. This is most applicable to residential tract subdivision developers and homebuilders. However, those refund provisions have now been removed and, as expressed within the introduction of the new schedule, "All payments received for new or upgraded service under provisions of this schedule shall be non-refundable."

While the 1,000 foot free extension did not apply to subdivision developers or commercial customers, there were alternative "free extension" policies under the old Service Schedule 3 as well as refund policies which have now been removed in the new schedule.

2.2 Tucson Electric Power (TEP) / UniSource Energy Services

Both UniSource Energy Services and Tucson Electric Power are companies of UniSource Energy. The new service schedules for both companies are practically identical.

Tucson Electric Power

Under the old schedule, up to 500 feet of electric line extension was provided at no cost to the customer as noted in the following text.

"Upon an applicant's satisfactory completion of required site improvements, TEP will make extensions from its existing overhead facilities of proper voltage and adequate capacity free of charge a distance of up to 500 feet."

However, the new policy eliminates this free extension.

"The Company will install, own, and maintain the distribution facilities necessary to provide permanent service to the Customer. Prior to the installation of facilities, the Customer will be required to pay the cost of the construction of the distribution facilities. The costs of construction are set forth in the Statement of Additional Charges. The line extension charges are based on the Company's current average cost of construction of distribution lines. The Company will review its costs and file a Pricing Plan revision annually. Such revisions will be subject to approval by the Commission before becoming effective."

Customers have been given six months from the effective date of the policy to allow for a transition period. The effective date is reported as December 1, 2008, meaning that applicants had until June 1, 2009 to be grandfathered under the old policy.

"From the effective date of these Rules and Regulations, there is a six (6) month grace period for Customers, developers and subdividers to execute a line extension agreement or receive approval on a new service application from the Company in order to be eligible for the line extension policy in effect between March 14, 2000 and November 30, 2008. Those new applicants must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the date of their respective agreement and/or application. In addition, all existing approved line extension agreements and service applications will be grandfathered in under the policy in effect from March 14, 2000 to November 30, 2008. Grandfathered Customers must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the effective date of these Rules and Regulations or they will be subject to the new line extension policy."

UniSource Energy Services

Under the old schedule, up to 400 feet of primary extension, 150 feet of service line, and one pole was provided at no cost to the customer. However, the new policy eliminates this free extension as noted in the following excerpt from the service schedule.

"The Company will install, own, and maintain the distribution facilities necessary to provide permanent service to the Customer. Prior to the installation of facilities, the Customer will be required to pay the cost of the construction of the distribution facilities. The costs of construction are set forth in the Statement of Additional Charges."

Similar to APS, there was no itemized publication of extension fees. In addition, customers were given six months from the effective date of the policy to allow for a transition period. However, the effective date is reported as June 1, 2008, so this grace period has ended.

"From the effective date of these Rules and Regulations, there is a six (6) month grace period for Customers, developers and subdividers to execute a line extension agreement or receive approval on a new service application from the Company in order to be eligible for the line extension policy in effect between August 11, 2003 and May 31, 2008. Those new applicants must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the date of their respective agreement and/or application. In addition, all existing approved line extension agreements and service applications will be grandfathered in under the policy in effect from August 11, 2003 to May 31, 2008. Grandfathered Customers must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the effective date of these Rules and Regulations or they will be subject to the new line extension policy."

3.0 Costs of Extending Electrical Service

In response to concerns from the public and reported average extension cost estimates of $9,200 per extension, APS and TEP have prepared extension estimates for various property conditions. The following estimates have been obtained with a map illustrating distances from existing electrical facilities to new customer properties.

3.1 Arizona Public Service

In recent settlement documents, APS submitted extension estimates for certain distances both above ground and underground. The following is taken from those documents:

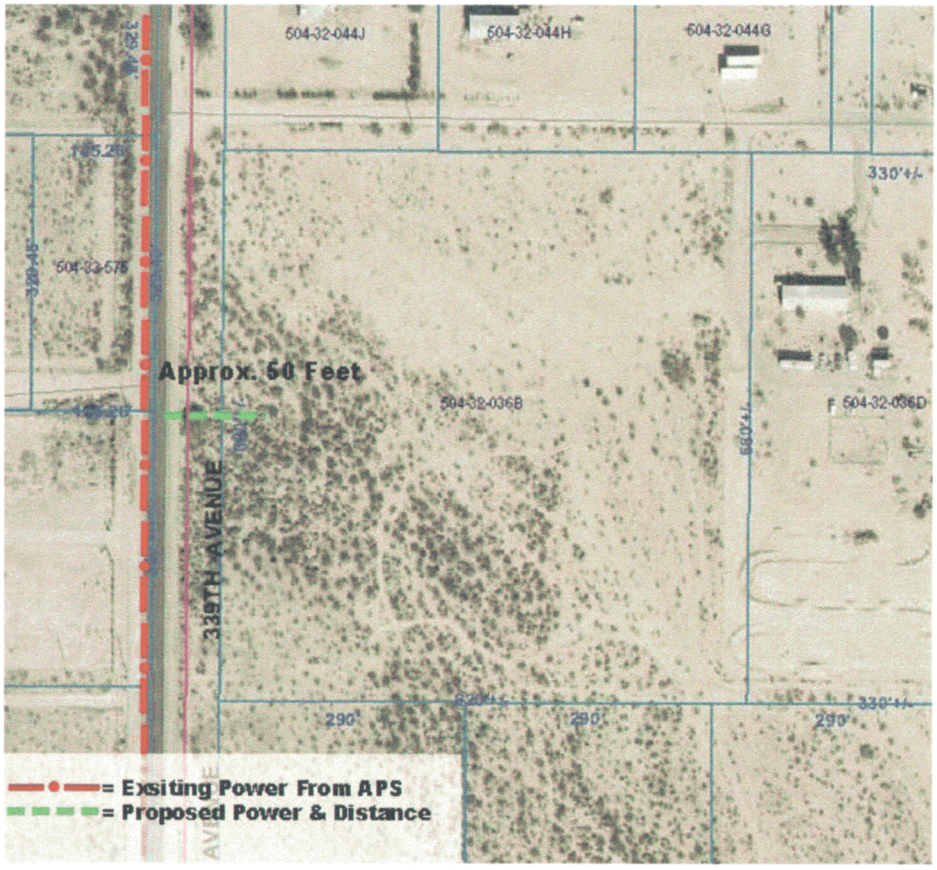
1000 ft. Overhead with 25 kVA transformer:	$19,400
750 ft. Overhead with 25 kVA transformer:	$18,500
500 ft. Overhead with 25 kVA transformer:	$14,000
1000 ft. Underground with 25 kVA transformer:	$10,900
750 ft. Underground with 25 kVA transformer:	$9,900
500 ft. Underground with 25 kVA transformer:	$9,000
Residential metro subdivision: $2,300 per lot	
Underground customer provides trench, conduit, and backfill.	

While the average cost of extensions over the last few years has been calculated at $9,200, it is evident that there is a wide range of potential costs.

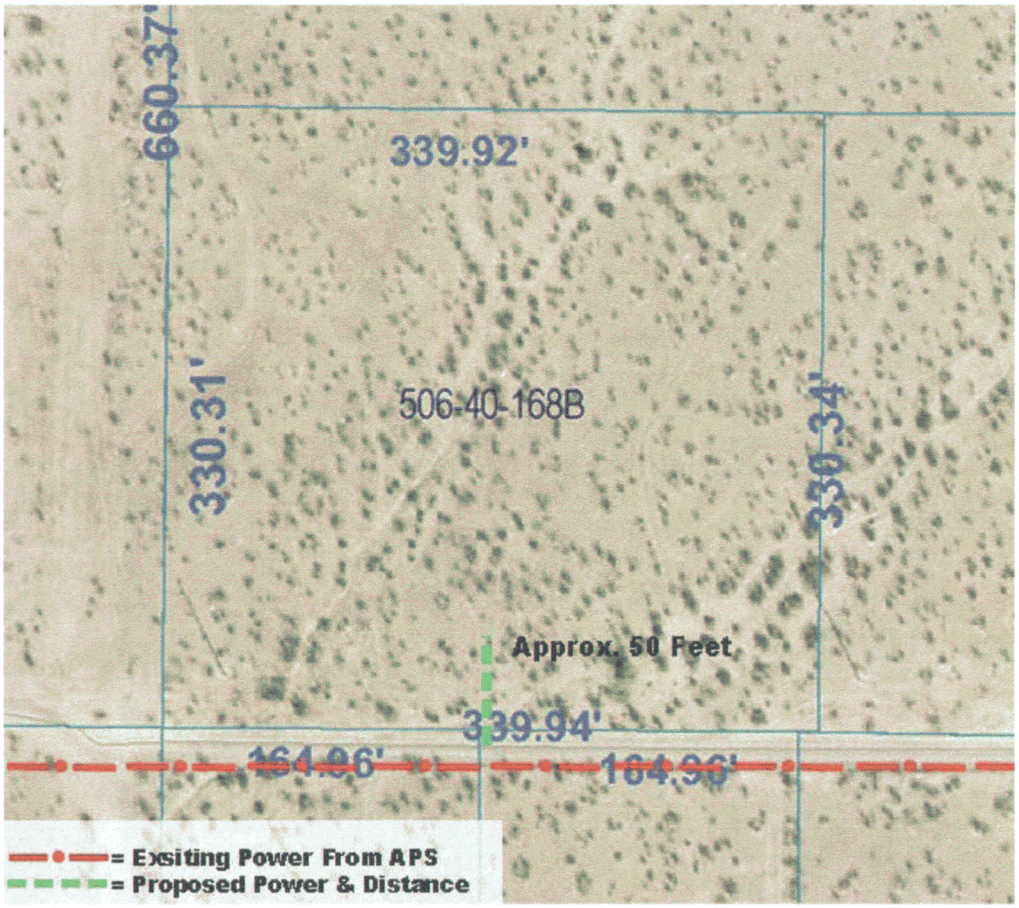
Single Residential Lot Estimates

The following are actual estimates produced by APS for various properties in the Buckeye area. The estimates are provided in full in an appendix at the end of this report. Maps of the properties have been included showing the parcel, existing APS power lines, and the approximate distance from power lines to the property.

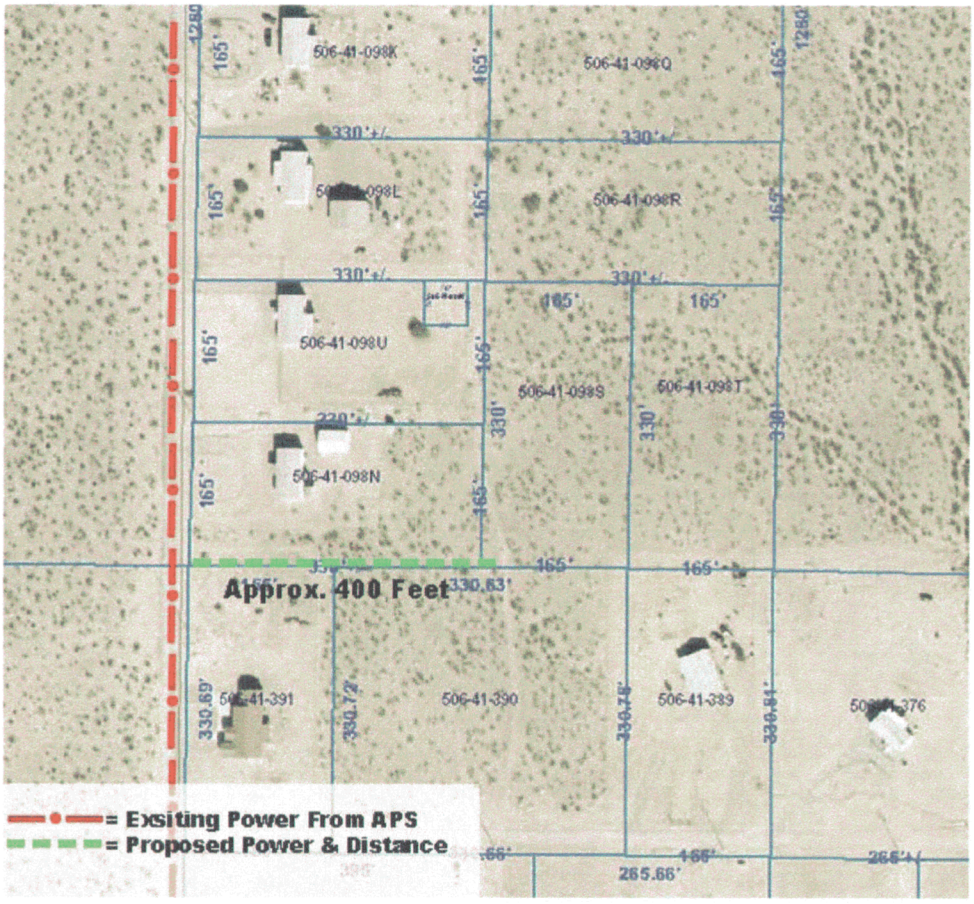
In the first example, electrical power is available along the street frontage. The overall distance to bring power to the home site is about 60 feet. APS's estimate is $10,800 including labor and materials. Materials include one pole, one transformer, primary wire, an estimated 200 feet of service line and a meter set.



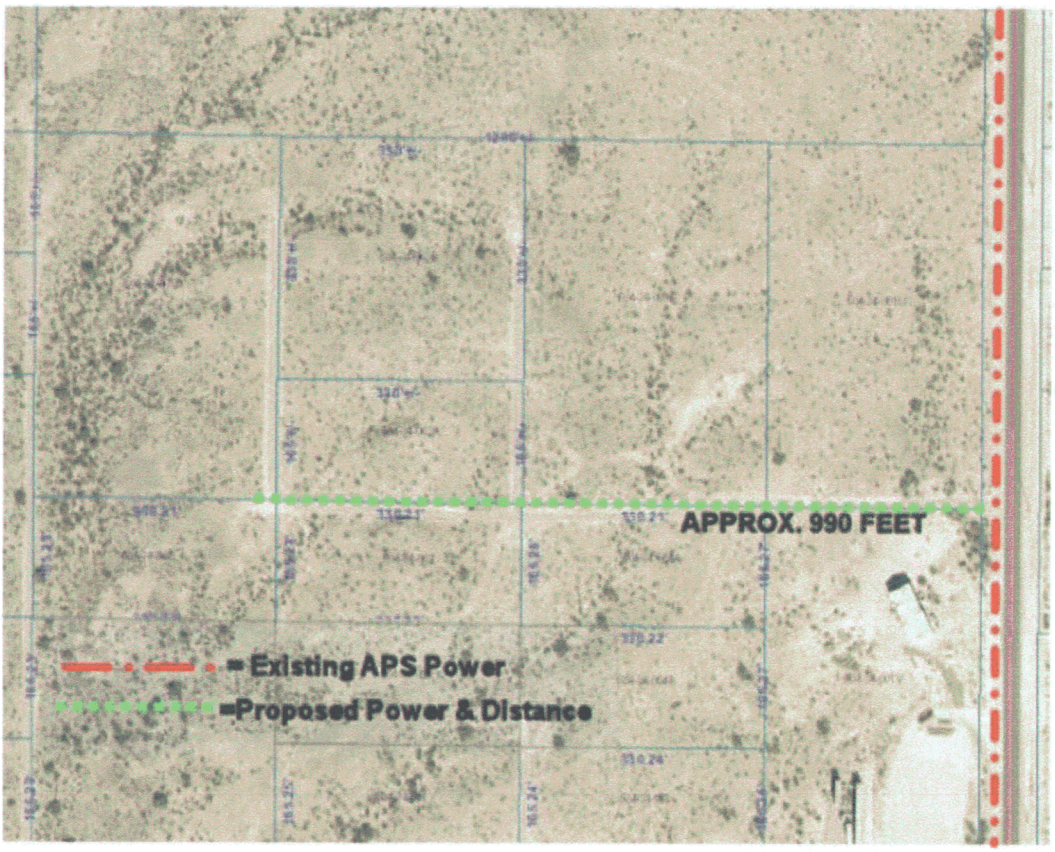
The second example is very similar with an approximate 50 foot extension from existing service lines. APS's estimate is $7,800 including labor and materials. Materials include one transformer, secondary line to a junction box, one junction box, service lines and a meter set.



The third example is an approximate 400 foot extension to an interior lot. APS's estimate is $21,200 including labor and materials. Materials include transformer, and lines to bring power up to lot line. This estimate does not include service runs or metering.



The final example is a 990 foot extension from an existing service line. APS's estimate is $25,400 including labor and materials for a 4 pole extension. This estimate does not include customer-provided trench and conduit costs. There may also be additional charges for street lighting.



Multi-Lot/ Subdivision Estimates

Anecdotally, several home builders are estimating that the added cost of extending service to a new subdivision could result in increased building costs of approximately $3,000 per lot for a typical subdivision. Though the costs of electrical extensions would have always been advanced in residential subdivisions under the old Service Schedule 3, builders anticipated that the advance would be refunded after homes became occupied and APS began generating revenue. Since the refund provisions have been eliminated, these costs will no longer be refunded to the builder. The cost of the extension will now mostly likely be passed on to the home buyer in the cost of the house.

3.2 Tucson Electric Power

The following is an itemized list of line extension charges that will be used for customers within TEP's service area.

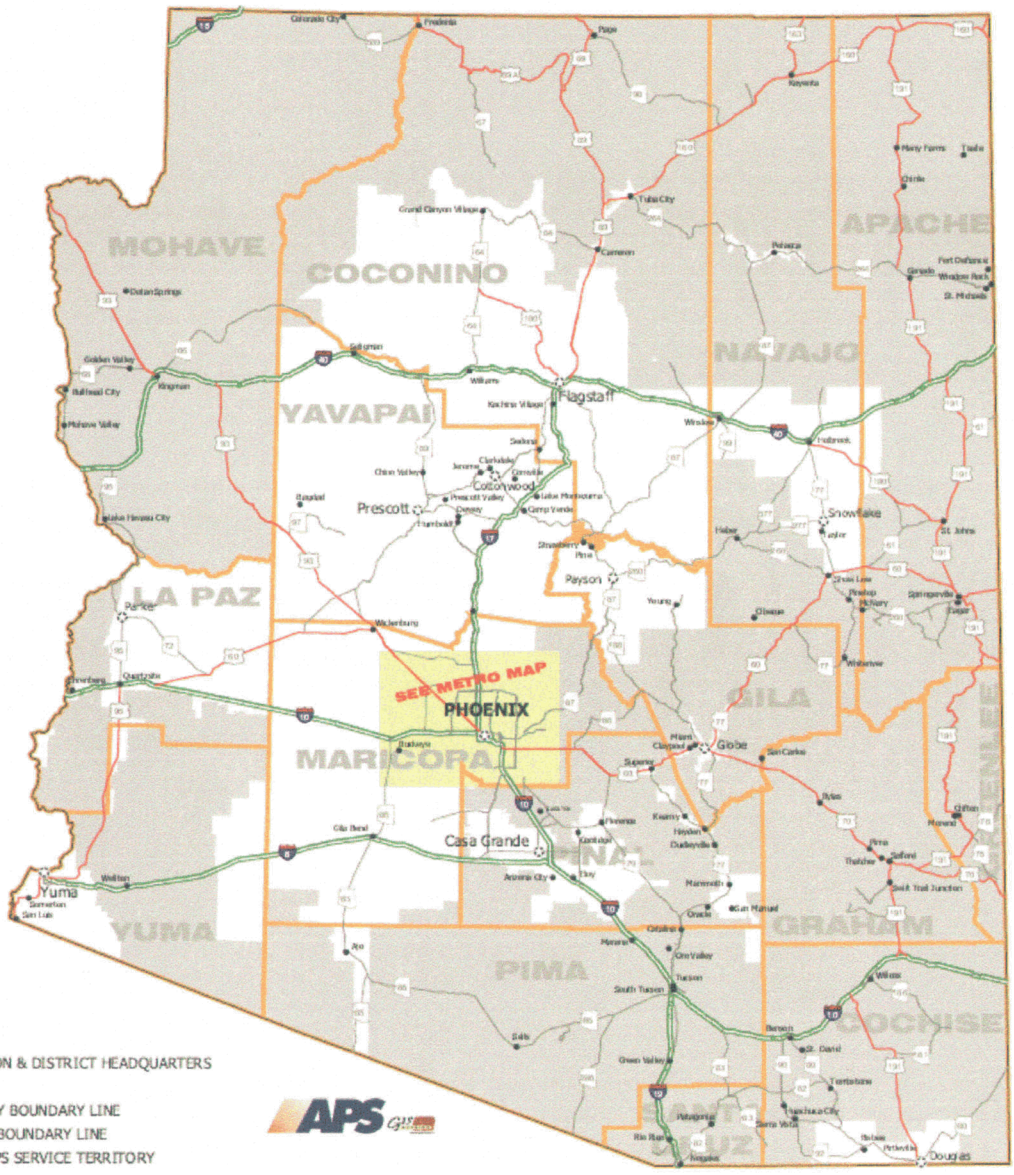
Line Extension Charges

1. Single-phase charge per foot	$18.00
2. Three-phase charge per foot	$64.50
Additional transformer charge for 500 kVA and under	$6,956.00
Additional transformer charge over 500 kVA	$16,275.00
3. Overhead feeder charge per foot	$36.00
4. Underground feeder charge per foot	$51.00
Additional charge per PME	$20,500.00

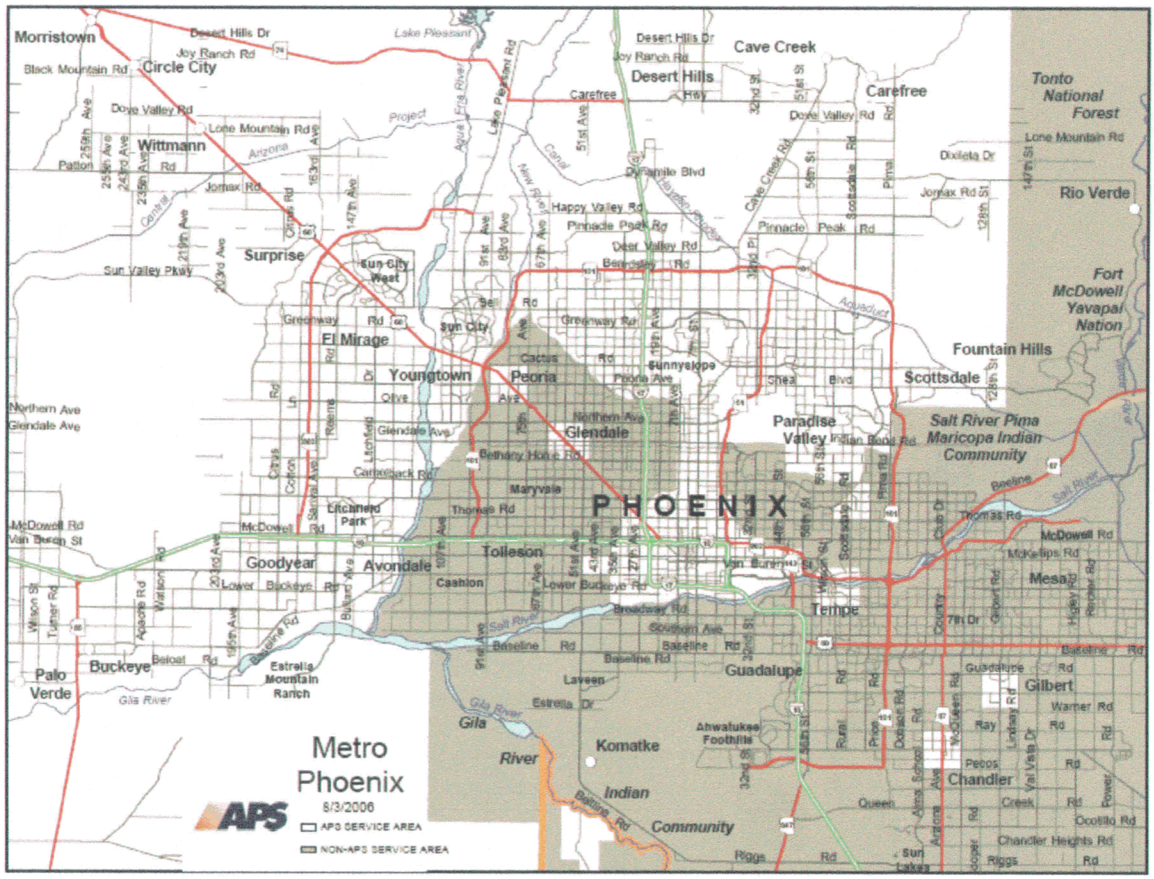
4.0 Potential Implications of Service Schedule 3 Policy Change

4.1 Affected Areas

APS provides electricity to a large portion of Arizona, particularly in the central, urbanized parts of the State. As the maps below illustrate, much of Maricopa, Yavapai, Coconino and La Paz counties are serviced by APS. In addition, APS is providing electric service to much of the populated areas of Pinal and Yuma counties with significant service areas in Cochise and Navajo counties as well. APS service areas are represented in white.

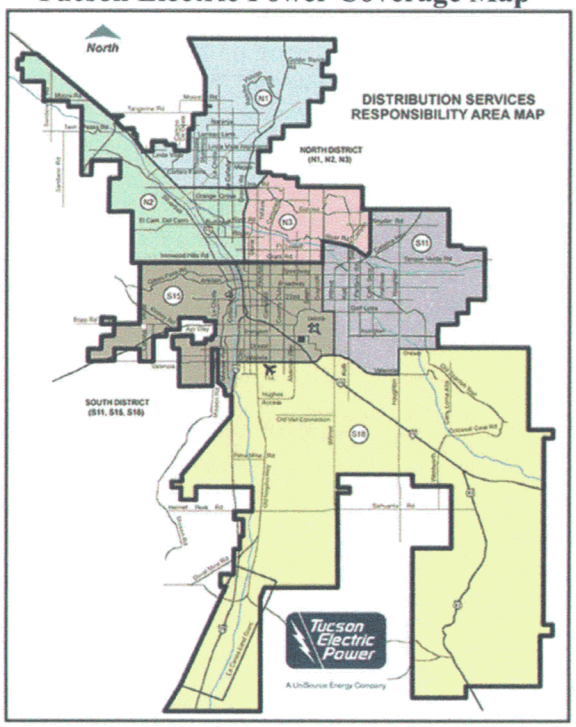


Within Maricopa County, APS covers much of the northern and western portions of Phoenix and its suburb cities. It also maintains service in the downtown Phoenix area, as well as downtown blocks of coverage in East Valley cities such as Tempe, Chandler and Gilbert. The map below shows all of these coverage areas in detail. APS service areas are represented in white.



Tucson Electric Power (TEP) covers most of the Metro Tucson area and UniSource Energy Services covers much of Mohave and Santa Cruz counties, as illustrated in the coverage maps below.

Tucson Electric Power Coverage Map



UniSource Energy Services Coverage Map

These maps are utilized to illustrate the geographic magnitude of impact that the policy changes will have in relation to the entire State. These three companies cover a majority of the population within the State.

4.2 Recent Sales Data

The changes in line extension policies instituted by APS, TEP and UES could have a significant impact on residential development and the value of vacant lots and land, particularly in areas where homes are built on large lots and where individual electrical service extensions must be made to a home site. This section will analyze the potential impact of the new line extension polices.

Sales data of recent transactions from individuals with land holdings primarily in the far west part of Greater Phoenix (Tonopah region) have been compiled to assist in the analysis. Most of the land that is represented in the following table would have been allowed electricity extensions free of cost under the previous APS schedule. Under the new schedule, homeowners will be required to pay for any extensions.

Recent Sales Transactions Far West Valley					
APN/LOCATION	DISTANCE FROM POWER	ACRES	PRICE	PRICE/AC	STATUS
401-95-008 (part of) 353rd Ave & Siesta Wy	0 FT	2.3	$45,000	$19,565	SOLD
504-32-036-B (part of) 339th Ave & Roeser Rd	0 FT	2	$50,000	$25,000	SOLD
506-40-168-F 369th Ave & Osborn Rd	0 FT	1.2	$32,000	$26,667	SOLD
504-34-064 390th Ave & Northern Ave	660 FT	3.45	$25,000	$7,246	SOLD
504-34-064 353rd Ave & Vineyard	700 FT	1.25	$8,500	$6,800	SOLD
504-12-146-B 345th Ave & Sherman St	840 FT	1	$13,000	$13,000	TRUSTEE SALE
401-42-005-J 339th Ave & Mountain Ave	990 FT	1.25	$12,000	$9,600	SOLD
506-33-010-R,S,T,U & V 425th Ave & Earll Dr	1200 FT	10	$65,000	$6,500	SOLD
401-43-012-P 371st Ave & Dobbins	1.5 MILES	2.5	$6,500	$2,600	SOLD
Source: Arizonans for Fair Power Policy					

There are many factors that affect the price of land including the availability of water, access to the property, paved and unpaved streets, sewer service or septic tank acceptability, surrounding uses and similar concerns. One of the most important is electrical service since most homes are not designed to function without it. With the recent change in electrical extension policies, the cost to extend electrical service to a home site is a significant issue not previously encountered by prospective homeowners. Without conducting a detailed statistical analysis of land prices in the rural parts of Greater Phoenix, the above table suggests that the distance from electrical service is having a negative effect on sales prices. With the added cost to place a home on a lot, at least a portion of the burden to pay for extending electrical service is transferred to the seller of a lot in the form of a lower value.

4.3 Potential Impacts on Property Tax Revenue

County assessors are beginning to lower values on land and homes due to the decline in housing values across Greater Phoenix and Arizona. The main cause of the decline 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 driven land prices down steeply as well. Based on interviews and letters of submission by various county assessors, in addition to recent sales data provided to this firm, the policy changes to eliminate free electrical line extensions means that proximity to existing electrical service lines will likely be correlated with land value.

In theory, a taxing entity such as a county can set property tax rates such that they raise a desired amount for their budget regardless of the total assessed value of the county provided that:

- The county does not levy an amount greater than the maximum allowable amount for that year as dictated by state statute, and
- The sum of levied property taxes from all taxing districts cannot exceed 1% of the value of properties containing owner-occupied dwellings.

Thus, if properties in a county lose value, the taxing entity is within their rights to raise the property tax rate to maintain the budgeted level of revenue.

However, it is generally believed that this is politically risky to do so because it is perceived as a tax increase, even if the total tax liability remains unchanged. This leaves taxing districts forced to deal with lower revenues if the value of property has declined and it is difficult to raise rates to make up the difference.

4.4 Interviews Regarding Impact of APS Policy Change

Various parties were interviewed regarding the impact of the APS policy change. A summary of the interviews follows.

- Homebuilders Association of Central Arizona
  Spencer Kamps of the Home Builders Association of Central Arizona (HBACA) was contacted to assess the reaction of homebuilders among the Association's members. Mr. Kamps spoke about several issues including an estimate of the cost of the new policy on a per lot basis (for production home builders), the inequities that they perceive to be occurring and the potential consequences going forward.

  Anecdotally, several builders are estimating that the added cost of extending service to a new subdivision could result in increased building costs of approximately $3,000 per lot for a typical subdivision. Builders were already responsible for the entire internal infrastructure within a subdivision, so the added cost per lot is directly tied to the new service schedule policy. It was also speculated that commercial developments would likely face much larger costs due to the electrical load that some commercial operations require. This would especially be the case for industrial manufacturing operations.

  In addition, it was noted that a production builder at least has the advantage of spreading the large initial capital cost among all of the lots within their subdivision, whereas an individual on a single lot would bear the full costs of necessary infrastructure, potentially creating a prohibitive development scenario for many in such a situation.

  In terms of inequities, the biggest issue that was expressed was the absence of any form of a "payback" provision when development occurs near an existing electrical line extension paid for by another party. Thus, without such a provision, the initial subdivision in a new service area bears all costs related to extending service and

subsequent adjacent owners/developers can tap into the electrical improvements at no cost.

Many builders also feel it is unfair and arbitrary to exempt development occurring within designated Indian Reservations from the line extension policy.

The added costs to builders could affect several entities based on the economic climate and the supply of available land. During a healthy housing market with strong increases in housing values, electrical infrastructure costs would likely be passed on to the purchaser of a home and there would be little notice of the increased cost. However, if vacant land that is viable for homebuilding does not have access to electrical infrastructure, homebuilding companies may be inclined to offer less for the land, particularly if nearby property is already served by electrical system improvements. Landowners may see a decline in value for their property reflecting at least a portion of the cost of the electrical infrastructure.

During an average to poor housing market, for example during the current housing market of Greater Phoenix, slow growth in the supply of new housing and an oversupply of existing housing units likely produces different results. Currently there are many housing options available to consumers and prices have declined to unprecedented levels. Homebuilders who are targeting their home pricing to the foreclosure and resale market may not be willing to pay for extraordinary infrastructure costs such as electrical line extensions. Builders would then have two options:

- Absorb the electrical line extension costs resulting in smaller profit margins, or
- Pay less for the subdivision land resulting in declining land values.

If there is a limited supply of land in a particular sub-market of Greater Phoenix, the cost of the electrical infrastructure would likely be shared between landowners and builders (through reduced land values and smaller builder profits).

Another issue that was raised was the option for builders to reduce other infrastructure costs to pay for the additional costs of electrical line extensions. This would come in the form of reducing consumer choices for services within a given subdivision. For example, a builder could forgo the installation of gas lines in the subdivision to make up for the added costs of the electrical infrastructure. Ultimately the homeowner "pays" for these fewer options by being restricted to the use of electrical appliances.

Overall, it was expressed that government-related costs have not corrected nor responded to Arizona's current real estate market conditions. While the cost of labor, materials and land have decreased due to the decline in demand, governmental costs in the form of taxes and fees have not yet declined. The decision by the Arizona Corporation Commission to increase the cost of development in the current climate is viewed as an additional cost imposed by government and appears contrary to what market conditions would dictate. Additionally, the HBACA has been informed by various parties that there is available capital for real estate investment but the deployment of that capital is awaiting the adjustment of governmental costs before any such investment occurs.

- La Paz County Assessor
  George Nault, an assessor for La Paz County was contacted for a reaction from a rural county that is primarily serviced by APS. In Mr. Nault's opinion, the recent devaluation of most vacant property within the county was significantly related to the elimination of the free footage allowance. He stated that it is difficult to separate the effect of the downturn in the economy from the APS policy change. However, based on interactions with landowners and realtors, the consensus was that the policy change was driving down the price of land and discouraging potential buyers from purchasing land that does not have electrical lines to the property.

4.5 Submitted Letters

Numerous letters have been submitted to legislative leaders and members of the Arizona Corporation Commission (ACC). Letters reviewed by this firm include those from homeowners, realtors, business owners, legislative leaders, and county officials. All have expressed concern in one aspect or another to the new service schedule. In addition, requests have been made to APS and the Residential Utility Consumer Office (RUCO) regarding comments on the change to the service schedule. Responses have been documented and communications have been summarized below.

Letters to the ACC

Numerous letters have been submitted to the ACC regarding the policy change of eliminating the 1,000 foot free extension of service. Homeowners and business owners have expressed frustration with the unexpected costs they have been required to bear. Some purchases and investments were made on the assumption that electrical service would be provided free to their property. Now they are forced to pay for service or forfeit their plans.

Realtors have advised that the policy change will adversely affect the residential market beyond the housing crisis that has affected the Arizona market. As noted previously, land prices appear to be declining relative to the property's distance from existing electrical lines. These realtors have also expressed frustration on behalf of individuals who purchased land and now feel that they were misled.

A letter from the Yavapai County office of the assessor has been submitted to the ACC describing the difficulty in valuing land based on the new service schedule and the expected devaluation of vacant property within their county as a result of the elimination of the free footage allowance. This is likely the case for all assessors across the State.

Additionally, letters from the La Paz County, Navajo County and Pinal County Boards of Supervisors have been submitted on behalf of themselves and their constituents. These letters describe the hardship that individuals are now facing due to the sudden increase in costs and the perceived unfairness of exempting certain groups and the lack of choice for electrical service.

The La Paz County Board of Supervisors was unanimous in their request for re-instating extension policies. They referred to the financial hardship that individuals are undergoing and

the effect that it will have on current and future growth; growth that they are dependant upon to sustain services and economic responsibilities.

Letters of Response by APS

APS was asked to respond to numerous questions posed by members of the ACC. These questions are similar to the issues addressed in this report. There are a few interesting responses worth noting for additional perspective on this issue.

APS provided a brief history of the line extension policy and outlined decisions that were made resulting the current policy. In 2007, APS proposed drastic changes to Service Schedule 3. The proposal included replacing the free footage allowance with equipment allowances and refundable extension allowances. However, the decision by the ACC was to remove all provisions for free footage, equipment allowances, feasibility studies and refunds.

APS also quantified the number of customers that have or would qualify for free extensions annually over the last four years. They ranged form a low of 419 in 2008 (an extremely low number of units were built in the broader region as well) to a high of 1,783 in 2006 (the peak year in housing construction over the last few years). These figures are utilized in the following section (Section 5.0) to estimate the total number of homes that may have qualified for free extensions among all three companies' service areas.

4.6 Summary

It is unclear the extent that an 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. It appears, however, that the majority of any impact related to the change in Service Schedule 3 will fall upon the non-urbanized areas and communities of the State rather the more urbanized counties of Maricopa and Pima.

When the cost for an electrical service extension is spread across the typical single family subdivision, the impact is much less per homebuyer if costs are passed forward or buried essentially within all the other infrastructure costs of subdivision development. This is not to imply that the cost is not significant; rather the cost is smaller on a per unit basis. However, for a lot owner in a more rural setting, the cost can be significant. In fact, the cost of an electrical extension may exceed the initial purchase price of the lot. The transition period for instituting the policy change reportedly caught many lot owners and buyers by surprise. In the short term, this means lot values will possibly decline further.

A reasonable range of effects of the change to Service Schedule 3 can be estimated through use of economic modeling techniques that quantify the economic and fiscal impacts associated with gains or losses of such activity. The following section will address this issue.

5.0 Economic and Fiscal Impacts of Suppressed Growth

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. On the other hand, it is possible to provide some general perspective into the possible economic losses through use of economic modeling.

For some brief background on economic modeling, the different types of economic impacts are known as direct, indirect, and induced, according to the manner in which they are generated. For instance, direct employment consists of permanent jobs held by a company or industry. Indirect employment is those jobs created by businesses that provide goods and services essential to the operation of that industry. Finally, the spending of the wages and salaries of the direct and indirect employees (and homeowners) on items such as food, housing, transportation and medical services creates induced employment in all sectors of the economy, throughout the State.

5.1 Assumptions of Analysis

For the purpose of this analysis and to illustrate the potential economic and fiscal impacts of lost residential construction, the analysis is conducted in increments of 100 single family homes with an average value of $180,000 per unit (for a total value of homes sold annually of $18 million). The construction cost of each 100 homes would be $10.4 million based on a survey by the National Association of Home Builders. It was assumed that 5% of all homes would be rented. All figures are in 2009 dollars.

Assumptions of Analysis

RESIDENTIAL	Units	Avg.Size per Unit	Value per SF	Value per Unit	Percent Leased	Lease per SF
Low Density Residential	100	1,800	$100	$180,000	5%	$12

Sources: Elliott D. Pollack & Co., MAG, ASU Construction Reports, PMHS.

For perspective on this incremental impact approach, the following data was reported by APS. Annual estimates from 2005 to 2008 of homes that likely met the requirements of a 1,000 foot free ($25,000 cap) extension are displayed below.

Number of Work Orders For Footage-Based Extensions

Year	Extensions[1/]
2005	1,410
2006	1,935
2007	1,499
2008	687

1/ Extensions include half of the extensions made over 1,000 feet.

Source: APS

It is difficult to forecast over the long term the number of residential units that would normally have qualified for a free extension based on the last four years of a boom and bust housing cycle. However, extensions have apparently represented between 3.5% and 9.5% of total APS residential customer growth in the years that data was available. That equates to a four year average of 5.2% of customer growth. Residential customer growth in APS service areas averaged 3.6% from 1996 through 2008. Using that figure as a long term growth rate going forward (growth will be slower in the next few years), APS would grow by approximately 35,240 customers each year.

In addition to APS, Tucson Electric Power (TEP) and UniSource Electric (UES) will continue to gain customers. TEP has averaged 2.2% annual growth since 1996 and UES has averaged 2.1% annual growth since its acquisition in 2003. Combined, the two companies are estimated to add over 9,820 customers annually on a long term average basis.

In the long run, the three affected service areas will likely grow annually by roughly 45,000 customers. That figure may be much less over the next few years as the excess housing stock in the State is absorbed. Extrapolating the four year average of customers qualifying for free extension footage across all service areas yields an estimated 2,340 customers annually that may have qualified for free footage allowances in the past. It is possible that a portion of these customers:

- May not build at all due to higher development costs,
- May not purchase land where an electrical service extension is required,
- May delay construction until a later date,
- May negotiate a price for the property that takes into account a portion, if not all, of the cost of the electrical service extension, or
- May purchase a home where electrical service extensions are already paid for or are not as costly.

Any impact would be more noticeable in the short term as excess quantities of developable land (some already with improvements made) offer competition.

Extensions as a Percent of Customers

	Extensions	APS Customer Growth (Residential)	Extensions % of Residential Growth
2005	1,410	40,188	3.5%
2006	1,935	36,917	5.2%
2007	1,499	21,801	6.9%
2008	687	7,225	9.5%
Total 2005-2008	**5,530**	**106,131**	**5.2%**

Long-Term Estimate of Extensions (Affected Areas of APS, TEP, & UNS)

Annual Customer Growth (APS, TEP, UNS)[1/]	Extensions % of Growth[2/]	Annual Extensions	Range of Extensions
45,000	**5.2%**	**2,340**	**1,578 - 4,279**

1/ Annual Customer Growth is calculated using the current customer base multiplied by each company's long-term average growth rate. Calculations have been rounded.

2/ Percentage of growth estimated to qualify for free extensions under previous policies. The four year average of qualifying APS customers has been extrapolated over all affected service areas.

Source: Pinnacle West, APS, ASU Construction Reports, Elliott D. Pollack & Co.

5.2 Impact of Lost Residential Development Due to Policy Change

This section of the analysis provides an estimate of the potential economic and fiscal impact of residential construction that is lost due to the change in the electrical service extension policy.

Economic Impact of Construction

The following table provides the economic impact of construction for each 100 single family homes built (or not built) in the State of Arizona. The annual economic impact on an individual community could be significant. The economic output (or "value" added) to the community is more than just the construction outlay. Construction activity creates jobs and local spending throughout a community and creates further valuable economic benefits. These benefits take the form of additional business opportunities within a community and additional job opportunities for area residents. These economic values (also known as direct, indirect, and induced impacts) are quantitatively estimated in this report.

The $10.4 million in direct construction costs for 100 single family homes would result in 53 direct construction jobs with $2.8 million in annual wages. The "ripple effect" of this construction would generate an additional 59 indirect and induced jobs with $2.7 million in wages and $7.4 million economic activity. Overall, the annual impact of 100 single family homes generates 112 jobs in the economy, $5.5 million in wages, and $17.8 million in economic activity.

Although the primary impact of the residential construction would focus on the municipality in which it was located, the respective county and State of Arizona would also benefit from this development.

Economic Impact from Construction
State of Arizona
(2009 Dollars)

Impact Type	Person Years of Employment	Wages	Economic Output
Residential (100 Homes)			
Direct	53	$2,809,152	$10,444,729
Indirect	33	$1,626,558	$4,253,470
Induced	26	$1,108,656	$3,107,265
Total	**112**	**$5,544,365**	**$17,805,464**

1/ The total may not equal the sum of the impacts due to rounding. All dollar figures are in constant dollars. Inflation has not been included in these figures.
Source: Elliott D. Pollack & Company; IMPLAN

Fiscal Impact of Construction

The fiscal effects of construction have been divided into primary and secondary impacts, depending on their source and how the dollars flow through the economy into tax accounts. For instance, some revenues, such as construction sales taxes, are definable, straightforward calculations based on the cost of construction. These revenues are described in this study as primary revenues.

Secondary revenues, on the other hand, flow from the wages of those direct, indirect and induced employees who are supported by the project. Revenue projections are based on typical wages of the employees working in the project, their spending patterns, projections of where they might live, and other assumptions outlined earlier in this report. This spending certainly enters the economy, but it is not as defined as primary revenues.

State of Arizona Fiscal Impact of Construction

The table below provides the fiscal impact on the State of Arizona from the construction of 100 single family residential units. Based on the total sales price of the units of $18 million, the State would collect a construction sales tax (and speculative builders tax) of $655,200. Secondary revenues from construction employment total $263,100 for a total fiscal impact on the State of $918,300.

Incremental Fiscal Impact from New Construction
State of Arizona
(2009 Dollars)

	Primary Revenues	Secondary Revenues from Employment					
Impact Type	Construction Sales Tax	Employees Spending Sales Tax	Income Tax	Vehicle License Tax	Unemp. Tax	HURF Tax	**Total Revenues**
Direct	$655,200	$42,551	$52,221	$17,194	$9,990	$9,200	**$786,356**
Indirect	N/A	$25,470	$28,075	$10,786	$6,267	$5,771	**$76,369**
Induced	N/A	$18,486	$19,136	$8,474	$4,923	$4,534	**$55,552**
Total	**$655,200**	**$86,507**	**$99,431**	**$36,454**	**$21,181**	**$19,504**	**$918,277**

1/ The figures for the State of Arizona include revenues distributed to counties, cities, and towns. The figures are intended only as a general guideline as to how the State could be impact by the project. The above figures are based on the current economic structure and tax rates of the State of Arizona.

Source: Elliott D. Pollack & Company; IMPLAN; Arizona Department of Revenue; ATRA

County Fiscal Impact of Construction

Among Arizona counties, the average construction sales tax rate of 0.74% would generate direct revenues of $86,000. Additional secondary employee impacts of $58,000 are generated for each 100 single family units, assuming most of the construction employees live within that county. In total, the typical Arizona county could lose approximately $144,000 in revenues for each 100 single family units not constructed. This figure would fluctuate depending on the actual number of construction employees residing in the county (which could be significantly less for rural counties) and the actual tax rates of each county.

Incremental Fiscal Impact from New Construction
County Level
(2009 Dollars)

	Primary Revenues	Secondary Revenues		
Impact Type	Construction Sales Tax	Employees Spending Sales Tax	Residents Property Tax	**Total Revenues**
Direct	$80,137	$6,052	$24,217	**$110,406**
Indirect	N/A	$3,637	$15,192	**$18,829**
Induced	N/A	$2,659	$11,935	**$14,594**
Total	**$80,137**	**$12,349**	**$51,344**	**$143,829**

1/ The figures do not include revenues collected by the State and shared with counties. The figures are intended only as a general guideline as to how a county could be impacted by the project. The above figures are based on the current economic structure and average tax rates of Arizona counties.

Source: Elliott D. Pollack & Company; IMPLAN; Arizona Department of Revenue; Arizona Tax Research Association

Municipal Fiscal Impact of Construction

The following table provides the annual fiscal impact of the construction of 100 single family homes in a municipality within Arizona. The construction activity could generate $240,900 in construction sales tax, depending on the actual tax rate of the municipality (an average of 2.06% was used). An additional $9,000 in secondary revenues could be generated from the spending of construction employees. Again, this figure would fluctuate depending on the actual number of construction employees residing in the community. The construction sales tax rate used in the analysis is the average for suburban cities in Metro Phoenix. In some cases, the construction activity could be located outside of a city and, therefore, no municipal tax would be collected.

Total Fiscal Impact from Construction
Municipal Level
(2009 Dollars)

	Primary Revenues	Secondary Revenues		
Impact Type	Construction Sales/ Speculative Builder's Sales Tax	Employees Spending Sales Tax	Residents Property Tax	**Total Revenues**
Direct	$240,900	$2,900	$1,700	**$245,500**
Indirect	N/A	$1,400	$900	**$2,300**
Induced	N/A	$1,200	$800	**$2,000**
Total[1/]	**$240,900**	**$5,500**	**$3,400**	**$249,800**

1/ The figures do not include revenues collected by the State and shared with cities and towns. The figures are intended only as a general guideline as to how an average city or town could be impacted by the project. The above figures are based on the average current economic structure and tax rates of Arizona cities and towns.

Source: Elliott D. Pollack & Company; IMPLAN; Arizona Department of Revenue; Arizona Tax Research Association

5.3 Fiscal Impact of Residents Occupying New Homes

In addition to the annual residential construction impact of 100 single family homes, tax revenues from residents of those homes would also benefit the State, county and municipality. If construction did not occur due to the electrical service extension policy, this revenue would be lost. This lost revenue can be quantified in terms of sales taxes from resident spending, property taxes on the homes they occupy and state shared revenues received based on population growth.

Unlike the impact from residential construction activity, the impact of single family dwelling residents is an ongoing, cumulative annual impact and, over time, would result in a significant impact on governmental revenues.

The following table provides an estimate of revenues for each 100 single family residences. In terms of assumptions for the calculations, spending estimates are based on the household income required to afford a $180,000 home multiplied by the estimated taxable spending for that income

bracket as determined by the Consumer Expenditure Survey. A leakage rate of 25% is assumed for municipalities, as it is likely that a portion of the total spending of the residents is spent outside city or town limits, no matter where an employee resides. Property taxes are based on a value per home of $180,000 and calculated based on the average of all Arizona counties and municipalities' property tax rates ($3.2385 and $1.2436 per $100 of net assessed value for counties and cities, respectively).

State shared revenues include income taxes, sales taxes, vehicle license taxes and Highway User Revenue Fund taxes collected by the State and shared with cities and towns mostly based on population. On average, each city or town within Arizona receive $300 per capita in State shared revenues while counties receive approximately $200 per capita.

In total, the State of Arizona receives $76,000 for every 100 households from spending in the economy. For a county, an estimated $119,900 is generated annually for every 100 households, and each municipality receives an estimated $134,500 for each new 100 households living in the city. These figures represent ongoing annual revenues that could be lost at each of the governmental levels if homes are not built as a result of electrical service extension policy.

Ongoing Fiscal Impact of New Residents
(2009 Dollars)

Assumptions	
Number of Homes	100
Average Persons per Household	2.73
Population in 100 Single Family Units	273
Value per home	$180,000
HH Income Estimate[1/]	$49,058
Spending Leakage Rate (Municipal Level)	25%
Average 2008 County Per Capita Revenue	$200
Average 2008 Municipal Per Capita Revenu	$300

Revenue per 100 Single Family Units	State	County	Municipality
Sales taxes from spending	$76,038	$14,429	$30,984
Property tax	N/A	$50,890	$19,541
Lease tax	N/A	N/A	$2,118
State shared revenue[2/]	N/A	$54,600	$81,900
Total annual revenues per 100 units	**$76,038**	**$119,918**	**$134,543**

1/ Estimate based on dedicating 30% of income to monthly housing obligation at the assumed housing price of $180,000

2/ The Arizona Department of Revenue typically recalculates state shared revenues from population growth every census year and mid-census year, effectively every 5 years. This calculation assumes the lost population would have an immediate impact, when in actuality it would be experienced in lump sum impacts as soon as the population would have been recorded.

Source: U.S. Census, AZ Dept. of Revenue, Elliott D. Pollack & Co.

5.4 Summary of Impacts

In summary, there could be both economic and fiscal impacts to governmental entities if residential development was indeed stifled by the electrical service extension policy. The economic impact of the construction of 100 single family homes would generate 112 jobs, $5.54 million in wages and $17.81 million in economic output. In terms of potential fiscal impacts, the State of Arizona would collect over $918,000 and the county in which homes would have located would collect approximately $144,000 in revenues. If homes are located within a municipality, the respective city would collect an estimated $250,000 from the construction activity. This represents economic activity and tax revenue that would be lost if 100 homes were not built.

The residents of each 100 homes would generate an additional $76,000, $119,900 and $134,500 each year for the State, the appropriate county and appropriate municipality, respectively, on a

cumulative basis. Thus, for the ongoing resident impact, the estimated fiscal impact would be replicated each year that the home is occupied. Over time, the cumulative impact becomes very significant for the State, counties, and municipalities.

Residential Impact Summary
100 Single Family Homes
(2009 Dollars)

Economic Impact of Construction (100 Single Family Units)	
Jobs	112
Wages ($ mil)	$5.54
Economic Output ($ mil)	$17.81
Fiscal Impact of Construction (100 Single Family Units)	
State of Arizona	$918,277
County Level	$143,829
Municipal Level	$249,800
Fiscal Impact of Residents (Ongoing & Cumulative Annually)	
State of Arizona	$76,038
County Level	$119,918
Municipal Level	$134,543

Source: Elliott D. Pollack & Company; IMPLAN

6.0 Conclusion

The policy changes enacted by the ACC have generated reactions from numerous individuals and entities, both public and private. From an economic perspective, the group that will realize the largest impact of these policy changes is landowners whose properties are not currently adjacent to existing electrical lines. To some extent, residential subdivision developers and homebuilders will be affected as well, but the cost of the electrical infrastructure is spread over a larger base of residential homes. Counties and municipalities that see any potential slowdown of residential construction activity due to the electrical service extension policy will also be affected by a slower-growing property tax base. In addition, some non-urban counties of the State are suggesting that the policy could have a much broader impact by affecting land values across their jurisdiction and ultimately their property tax base.

Every owner of vacant land within the affected service areas of APS, TEP or UES, whether they own a single lot or hundreds of acres, now bears the full costs of electrical infrastructure extensions. This cost in some circumstances may be paid through lower sales prices for landowners who wish to sell property. For owners of land planning to build a home, the cost is direct, equal to the amount of the extension. For these owners, the new policy may have created a prohibitive development scenario.

Production homebuilders have the advantage of spreading the large initial capital cost of extending electrical service among the many lots within their subdivision. However, they are still subject to increased costs that were previously refunded to them based on the benefit received from new customers. In a normal market, builders will likely negotiate lower land prices taking into consideration the increased cost of electrical extensions. Landowners will likely need to absorb at least a portion of the cost of the electrical extension.

In normal years, the service areas of the three utility companies affected by the electrical extension policy will likely grow annually by roughly 45,000 customers. That figure will be less over the next few years as excess housing is absorbed. Extrapolating the reported APS four year average of customers qualifying for free extension footage across all service areas yields an estimated 2,340 customers annually that may have qualified for free footage allowances in the past. It is possible that a portion of these customers will not build due to higher development costs if they did not receive an initial discount on the price of the land. Going forward, it anticipated that market prices will account for at least a portion of the additional cost of extending electrical service in the form of lower prices. Those landowners whose lots are not served by electrical improvements are the ones who are most impacted at the current time.

While it is unknown how many homes will now not be built due to the increased cost of electrical line extensions, it has been illustrated that just building 100 homes has a significant impact on job creation, economic activity, and governmental revenues, particularly in non-urban communities where the construction of homes on large lots is more the rule than exception.

A few primary points need to be made related to the impact of the service extension policies.

1. The primary impact of the policy change is on the non-urban parts of the State served by APS, TEP and UES. This includes parts of Maricopa County that are located outside of the region's cities and towns. Homes in these areas are usually constructed on large lots by individual builders or homeowners. The lots often have limited infrastructure in place, relying on individual wells, unpaved roads and septic tanks for sewage disposal. In many cases, the homes planned for construction may be less expensive prefabricated or manufactured units. In this situation, a substantial added cost for electrical service may be beyond the ability of the home owner to absorb. Those persons who currently own lots in these areas are the ones who are most impacted by the electrical service extension policies. They likely are trapped with an illiquid investment that may take years to sell.
2. The non-urban counties of Arizona served by APS, TEP and UES may feel the direct effects of slowed residential construction activity (and commercial construction activity) as well as reduced property tax bases. A letter from the Yavapai County assessor has been received concerning the effect on appraisals, property values and ultimately on the entire vacant land tax base. While analysis of the potential impact of the service extension policy on a jurisdiction's tax base are beyond the scope of this study, counties that have a predominance of large lot subdivisions and few, if any, production homebuilders, could feel a loss of tax base in addition to the decline in property values due to the current recession.
3. In economics, there is a theory called "substitution". Very simply, the theory is that as prices rise for a particular good, consumers will substitute away from higher price goods and services to less costly alternatives. This theory will likely come into play in evaluating the impact of the service extension policy on the choices made by potential land buyers and home buyers. For instance, if a prospective buyer of a vacant lot understands that the ultimate cost of home includes the price of the land and the electrical service extension, he may choose to:

    - Purchase the vacant lot for its attributes,
    - Choose not to purchase the lot due to the expense, but purchase a resale home where electrical service is already provided;
    - Purchase a vacant lot where the electrical service is nearby;
    - Not purchase a lot in the area, but move to a lot or home where the cost of electrical service is not so burdensome (such as a traditional tract subdivision home).

    There certainly are other substitutions or alternatives for a buyer to consider given their individual resources and preferences.

    This is the reason why it is virtually impossible to estimate the full impact of the new service extension policy. Many prospective buyers may actually purchase an alternative home or lot, but not in a location where electric service is a major cost. Counties in Arizona may still see some residential construction activity, but it may be in a different

form or location if there are adequate alternatives to substitute for the lots burdened by electrical service extension costs.

To summarize, the primary impacts of the new service extension policies will fall on two entities:

- Non-urban counties that have a predominance of large lot subdivisions and few, if any, alternative residential areas that will substitute for the expense of electrical service extensions. La Paz, Coconino, Navajo and Yavapai counties may fall into this category since there are few production builders in the area. As a result, the counties could feel a loss of tax base in addition to the decline in property values due to the current recession.
- Persons who currently own lots in areas not well served by electrical utilities are likely trapped with their investment or stand to absorb a substantial loss if they sell under the current service extension policies.

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*. The policy will mainly affect a select set of landowners, primarily in rural areas of the State.

Appendix A – APS Extension Estimates

APS *A subsidiary of Pinnacle West Capital Corporation*

Name Vicki Vance
Title CSR
Department Buckeye Construction

Phone: 623-932-6671
Mobile: 602-448-6821
Fax: 623-932-6633

Email Address
vicki.vance@aps.com
Physical Address
615 N 4th St
City, State, Zip
Buckeye, AZ 85326

November 18, 2008

Re: Lot 504-32-036B

Dear John,

This letter is in response to fax you sent me on November 13, 2008. The following price includes all labor and material for one pole, transformer, primary wire, an estimated 200' of service line and a meter set. Note that this quote is rounded to the nearest number and the final price may vary slightly. The estimated cost is $10,800.00

Any questions please feel free to give me a call at 623-932-6671

Sincerely;

Vicki Vance

APS *A subsidiary of Pinnacle West Capital Corporation*

Name Vicki Vance
Title CSR
Department Buckeye Construction

Phone: 623-932-6671
Mobile: 602-448-6821
Fax: 623-932-6633

Email Address
vicki.vance@aps.com
Physical Address
615 N 4th St
City, State, Zip
Buckeye, AZ 85326

November 18, 2008

Re: Lot 506-40-168B

Dear John,

This letter is in response to fax you sent me on November 13, 2008. The following price includes all labor and material for a transformer, secondary line to a junction box, the junction box, service lines and a meter sets. Note that this quote is rounded to the nearest number and the final price may vary slightly. The estimated cost is $7800.00

Any questions please feel free to give me a call at 623-932-6671

Sincerely;

Vicki Vance

APS *A subsidiary of Pinnacle West Capital Corporation*

Name Vicki Vance
Title CSR
Department Buckeye Construction

Phone: 623-932-6671
Mobile: 602-448-6821
Fax: 623-932-6633

Email Address
vicki.vance@aps.com
Physical Address
615 N 4th St
City, State, Zip
Buckeye, AZ 85326

November 12, 2008

John Wylie

Re: Power to Lots: 506-44-098S

Dear John,

This letter is in response to your conversation with George Quinones on November 12, 2008. The following price includes all labor and material, including transformers, for bringing power up to the lot lines. This price does not include any service runs or metering. Note that this quote is rounded to the nearest number and the final price may vary slightly.

Lot 506-44-098S – Three Pole Extension with OH Transformer = $21,200

Any questions please feel free to give me a call at 623-932-6671

Sincerely;

Vicki Vance

APS A subsidiary of Pinnacle West Capital Corporation

Name: Vicki Vance
Title: CSR
Department: Buckeye Construction

Phone: 623-932-6671
Mobile: 602-448-6821
Fax: 623-932-6633

Email Address: vicki.vance@aps.com
Physical Address: 615 N 4th Street
City, State, Zip: Buckeye, AZ 85326

March 11, 2009

John Wytlie
MGW, LLC
7835 W Camino Del Oro
Peoria, AZ 85383

Re: Conceptual Cost Review for Lot 504-34-001D

Dear John,

Thank you for your interest in locating a new project within the APS service territory. After a conceptual review of your project, based on the information you provided, we estimate the cost for providing electric service to be approximately $ 25,400.00. This is for a 4 pole extension coming off the 351st Ave to the Southeast corner of the lot. This cost includes all APS labor and material needed to get power to the customer. This estimate does not include customer provided trench and conduit costs.

The cost provided is for planning purposes only and is subject to change without notice. Additional costs may apply for street lighting. In order to proceed with firm pricing and a detailed electrical design, a study and design payment will be required.

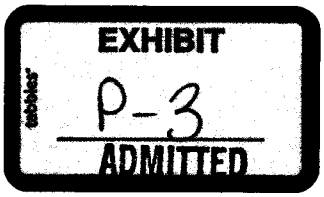
APS will extend service in accordance with the Conditions Governing Extensions of Electric Distribution Lines and Services, Schedule # 3 and the Terms and Conditions for the Sale of Electric Service, Schedule # 1, on file with the Arizona Corporation Commission.

I appreciate the opportunity to work with you and look forward to the successful completion of this project. If you have any questions, please call me at 623-932-6671.

Sincerely,

Vicki Vance
CSR
Buckeye Construction

Testimony of Barbara Wyllie-Pecora
In Opposition of Settlement Agreement
Arizona Public Service Company Docket No. E-01345A-08-0172



Q. WHAT IS YOUR NAME AND BACKGROUND?

A. Barbara Wyllie-Pecora. I am a mortgage broker, a real estate broker and vacant land owner.

Q. WHY DID YOU INTERVENE?

A. I heard that the Arizona Corporation Commission removed the 1000 ft. free electric extension and I thought, "who are they to make a decision like that without notice to existing property owners? Maybe I missed it and am 'grandfathered' in?" So, because the economy fell in the tank and my mortgage business ceased to make any money, I decided I would look into this issue. Yes, this economy gave me the time to learn about the "system" and draw some conclusions of my own.

Q. WHAT ARE YOUR CONCLUSIONS AFTER RESEARCHING SERVICE SCHEDULE 3?

A. First, the ACC made this 'change' in the summer of 2007, which had been in place since 1954. We are now in 2009 and the media and politicians say we are living in a period of extraordinary uncertainty in the economy and financial markets. Twenty years from now history may say we lived in an economy worse than the Great Depression of 1929. I know they try to refer to the present as a recession, but ask anyone who has lost a job, their home or can't afford to get power to their property. Are they depressed?

Second, let's say someone could buy an acre of vacant land for $30,000 and the power extension was free. Now, move ahead 5 years, and that 'someone' is ready to build their home on that vacant lot. Lo and behold, they find out a 'change' has taken place. Not only is the cost of the power extension not free, but it will cost them $25,000! How much is their vacant, one-acre lot worth now? Say the taxes on the property were $900 in 2003, and in 2008 the property taxes increased to $2,600. Is this fair? I would say a government agency devalued their property and all affected property owners in Arizona should be reimbursed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, and I thank the Arizona Corporation Commission for considering my testimony.

BEFORE THE ARIZONA CORPORATION COMMISSION

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 TESTIMONY RESPONSE

Barbara Wyllie-Pecora files the Response Testimony to Chairman Mayes' letter submitted to the docket dated August 5, 2009

RESPECTFULLY SUBMITTED this 21st day of August, 2009.

BARBARA WYLLIE-PECORA
Intervener

By Barbara Wyllie-Pecora
Barbara Wyllie-Pecora

ORIGINAL AND 13 COPIES OF THE FOREGOING filed this 29th day of July 2009 with:

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

EXHIBIT
P4
ADMITTED

August 20, 2009

The Honorable Kristen K. Mayes, Chairman
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

RE: Current APS Line Extension Policy – Service Schedule 3
Docket # E-01345A-08-0172

Dear Commissioner Mayes,

In response to the 25 state survey submitted to the docket by the Corporation Commission, as well as the 50 state survey submitted by Elijah O. Abinah of the AZ Corp. Commission Utilities Division, I submit a preliminary study done on various utility providers in eight states.

My research indicates that APS by far has the most expensive costs for new customers wishing to extend power to their homes. While many utility providers do not give free footage on par with APS' 1,000ft that existed prior to July, 2007, their costs appear to be much lower. I commend the Commission for exploring the free footage allowances of other utility providers, but I urge the Commission to use the resources available to them to research and discover the actual cost of extending power on a per-foot basis. This will more accurately and effectively provide a comparison of APS' costs against other utility companies.

Attached is a chart illustrating my findings that compares the amount of line extension $25,000 will get the customer according to estimates I have received from APS and the information I received from utility companies in the 8 states I researched.

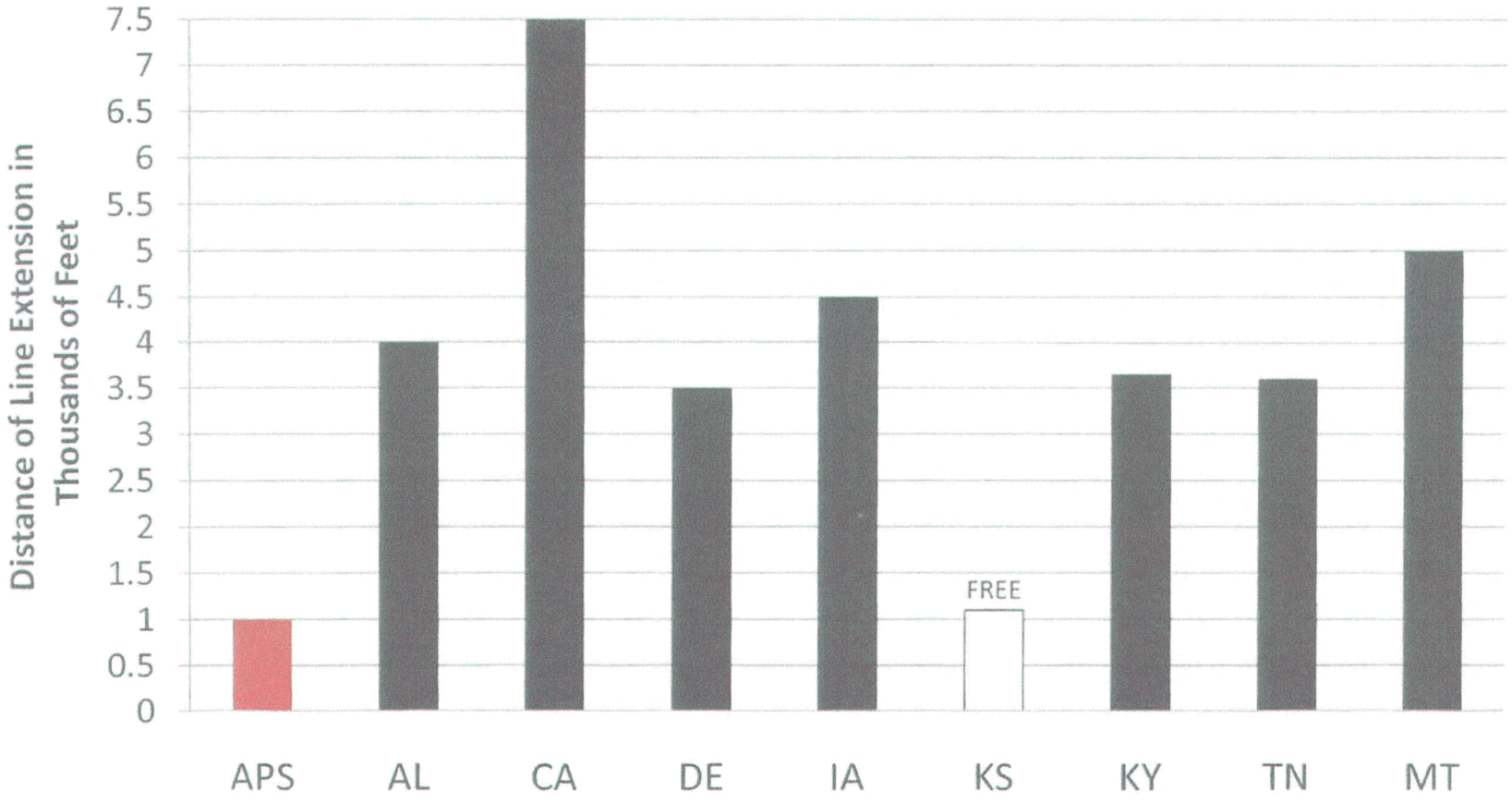
Respectfully,

Barbara Wyllie-Pecora

Barbara Wyllie-Pecora

What $25,000 Buys

A Comparison between other utility providers and APS



SURVEY OF UTILITY PROVIDERS IN EIGHT STATES

1. ALABAMA – ALABAMA POWER COMPANY (1-800-245-2244). I called this number and asked to be connected with an engineer that worked with line extensions in an outlying area. I spoke with an employee in the engineering department. According to him, they base the free footage allowance based upon the customers estimated 5 years of revenue on the extension. I estimated a monthly payment of $250 that would total $15,000 over 5 years. Without knowing exactly what an extension would cost on a per foot basis we are unable to accurately predict the distance a $15,000 allowance would cover. A conservative estimate of $10/foot was applied, arriving at a total extension of 4,000 for a $25,000 customer contribution.
   PER FOOT COST: UNKNOWN

2. CALIFORNIA – ANZA ELECTRIC. Spoke with the first customer service representative that answered the phone (951-763-4333). According to her, primary extensions cost $3.20/ft (overhead power) and $1.00/ft for secondary. The customer service representative also stated this information was available online at www.anzaelectric.org . I attached a page from their New Construction Packet that describes the fees.
   PER FOOT COST: $3.20 PRIMARY, $1.00 SECONDARY

3. DELAWARE – DELMARVA POWER (1-800-245-2244). Spoke with Mr. Williams in the engineering department. Line extensions are $7/ft for underground (which included them doing the trenching & supplying the casing). I based the distance of roughly 3,500 ft based on $7/ft.
   PER FOOT COST: $7 (APPROX)

4. IOWA – MIDAMERICAN ENERGY. I attached an estimate for an underground power extension of 900ft at approximately $4,400 for the complete job. APS has provided a table in Elliot Pollack's Study which gives the average cost of 1000 feet of underground extension. The cost is $10,000.00
   PER FOOT COST: $4.89

5. KANSAS – Provided rate schedules for two power companies, KANSAS CITY POWER & LIGHT COMPANY and WESTAR ENERGY, INC. Both company's schedules describe offering a ¼ mile free line extensions.
   PER FOOT COST: $0 (FIRST 1/4 MILE)

6. KENTUCKY – MURRAY ELECTRIC SYSTEM (1-270-753-5312). Spoke with a representative. The first 150ft. of overhead is free (that includes 1 pole). After the 150ft, they charge $2/ft for wire and $1,000 per pole every 200ft. Our conservative estimate has $25,000 paying for 3,650ft of line extension.
   PER FOOT COST: $7 (APPROX)

7. TENNESSEE – ERWIN UTILITIES (1-423-743-1844). Spoke with the engineering department. I asked them how much an 800ft. overhead line extension would cost, and I was told approximately $5,700 minus a $1,000 customer allowance for a total cost of $4,700 for the first 800ft. Each 800ft after would cost $5,700.
   PER FOOT COST: $7.125 (APPROX)

8. MONTANA – Spoke with a real estate agent who specializes in land sales and developing single family residential lots. According to him, you can conservatively estimate an extension to cost $5/ft. There is no charge for meters or transformers and a free-footage allowance of 150ft for overhead extensions.

MidAmerican
ENERGY
OBSESSIVELY, RELENTLESSLY AT YOUR SERVICE.

MidAmerican Energy Company
CUSTOMER TECHNICIAN
P.O. BOX 657
Des Moines, Iowa 50306-0657

March 23, 2009

Todd Omundson
8852 NE Morgan Dr.
Bondurant, IA 50035

Re: Electric service to a new home on SE 108th St. Polk County

Dear Mr. Omundson:

We are pleased to submit a proposal and drawing to provide an underground distribution extension for the above project using either an electric heating system or another fuel.

MidAmerican Energy Company will install underground primary cable and a pad mounted transformer to provide 120/240 volt, single-phase three-wire service as shown on the attached drawing. The applicant charge to provide this installation if the home is heated electrically is $4,433.59. If the home is not heated electrically, the charge is $5,586.89. This proposal is valid for 90 days and if MidAmerican Energy Company construction has not commenced within 12 months it may be voided. This proposal is based on the following terms:

MidAmerican Energy Company Proposes To:

1. Furnish and install underground primary cable between the transformer and MidAmerican Energy Company's distribution system.

2. Furnish and install the pad and pad mounted transformer to provide 120/240 volt, single-phase, three-wire service at the location shown on the drawing.

3. Connect the primary and secondary cable at the transformer.

4. Furnish and install the applicable electric meter.

MidAmerican
ENERGY
OBSESSIVELY, RELENTLESSLY AT YOUR SERVICE.

5. Furnish and install underground service from meter socket to MidAmerican Energy Company's transformer; this proposal does not include the cost for this installation. MidAmerican Energy Company will bill Applicant for the additional costs after installation is complete.

The Applicant Agrees To:

1. Furnish and install an electric meter setting by MidAmerican Energy Company's standards.

2. Grade the underground primary cable route to within four inches of final grade and clear the route of construction materials, obstructions, trees, etc. Extra costs for additional excavation beyond normal trenching operations due to unforeseen underground obstructions shall be paid by the applicant.

3. The Applicant agrees to indemnify and hold MidAmerican Energy Company harmless from any and all damages that may result from the non-tamping of backfill operations conducted by MidAmerican Energy Company. In case any action is brought against MidAmerican Energy Company, or any of its agents or employees, relative to such backfill operations, the Applicant shall assume full responsibility for the defense thereof. Upon failure to do so on proper notice, MidAmerican Energy Company reserves the right to defend such action and charge all costs to the Applicant, provided, however, that nothing herein shall be construed as an assumption of liability by the Applicant for damages and claims attributable to MidAmerican Energy Company's negligence.

4. Furnish an easement to MidAmerican Energy Company without cost. (Furnish survey drawing and/or legal description for easement preparation.) If a 3rd party easement is required any cost associated in obtaining the easement will be paid by the applicant.

MidAmerican
ENERGY
OBSESSIVELY, RELENTLESSLY AT YOUR SERVICE.

5. Be responsible for complying with all aspects of compliance as required by any local, state, or federal permit or plan associated with storm water pollution prevention or erosion control. It is specifically understood and agreed that MidAmerican Energy Company is providing the service requested by the Applicant solely for the Applicant. MidAmerican Energy Company will not become or agree to become a co-permittee or operator for the purpose of applicants' compliance with any local, state or federal permit or plan associated with storm water pollution prevention or erosion control.

If MidAmerican Energy Company is required to start construction of underground electric facilities during the winter season, the work will be subject to an additional winter construction charge.

There is also an additional charge for connecting and disconnecting your temporary construction power pole, which is not included in any of the costs of this proposal. If this additional service is required, MidAmerican Energy Company will bill the Applicant accordingly.

The undersigned certifies that the structure served by the electric distribution system meets the energy conservation standards as contained in the Iowa Administrative Code Section 661-16.800 sometimes known as the "State Building Code Thermal and Lighting Efficiency Standards."

It is MidAmerican Energy Company's responsibility to see that the various utility companies' facilities are located before our construction. This includes electric, natural gas, telephone, cable television, and generally water. It is the owner's responsibility to see that any privately owned systems such as water systems, such as water services, irrigation systems, drain pipes, septic lines and underground wiring are
located before MidAmerican Energy Company's construction. MidAmerican Energy Company assumes no liability for private facilities that are not located.

MidAmerican
ENERGY
OBSESSIVELY, RELENTLESSLY AT YOUR SERVICE.

All MidAmerican Energy Company installed facilities will remain the property of MidAmerican Energy Company. MidAmerican Energy Company alone will determine whether the facilities will or will not be used to provide other services or extensions to serve other customers.

Please advise which proposal is satisfactory, sign and return one copy of this letter to me. Please include payment for the appropriate proposal selected. MidAmerican Energy Company will release the work for scheduling upon receipt of the signed proposal, payment, and easement. If you have questions please call me at 515-242-3902.

Sincerely,

MidAmerican Energy Company

Bill Smalley

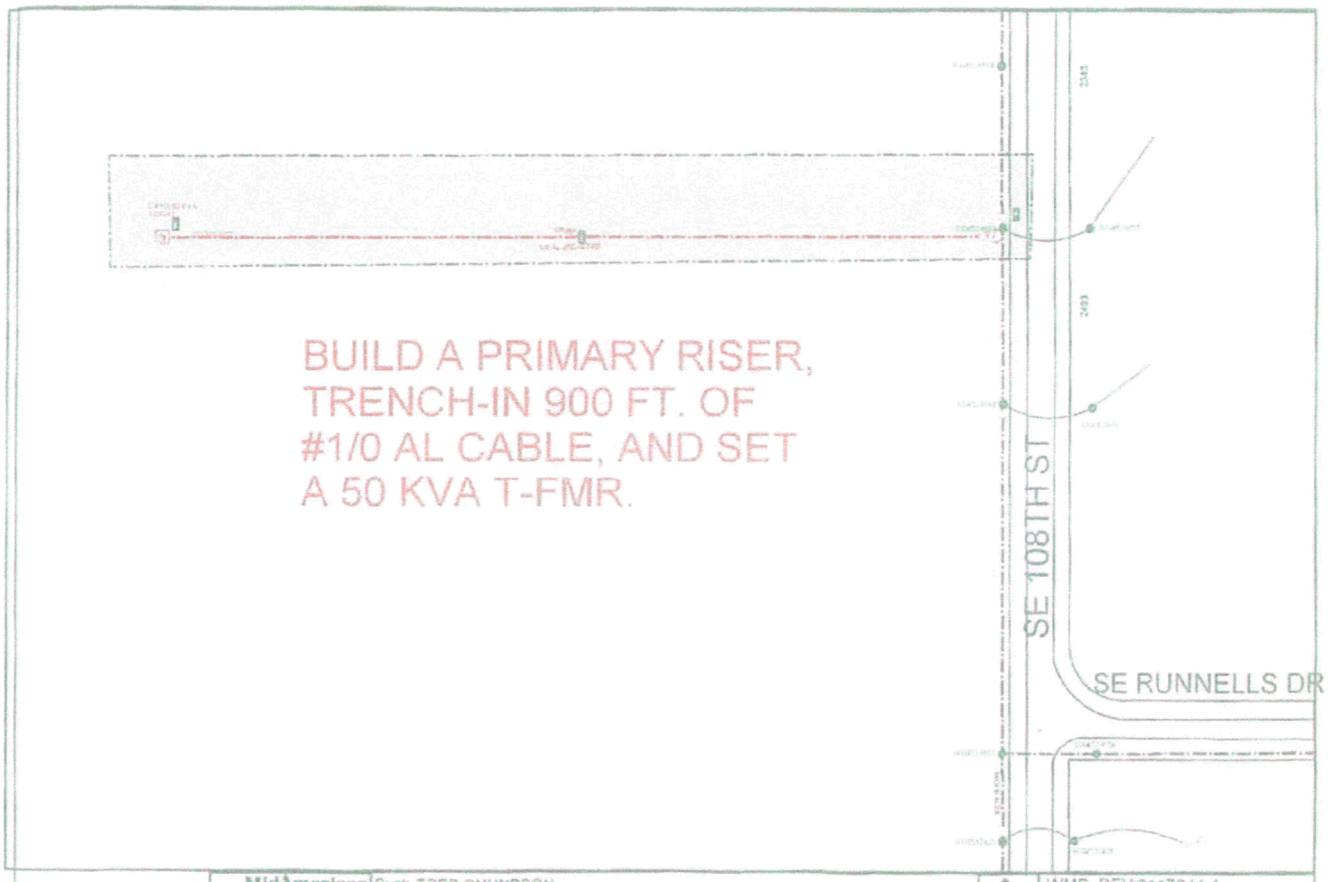
William H. Smalley
Customer Technician

_____ All Electric $4,433.59

_____ Gas & Electric $5,586.89

Accepted By: _____

Date: _____ Date Service Required: _____



MidAmerican Energy

Cust: TODD OMUNDSON
Addr: 0 SE 108TH ST ST
Crew HQ: DMDL
City: POLK COUNTY SE
X = 1,672,988 Y = 568,866

WMS_REV:2117944-1
Date: 3/16/2009
Scale: 1 in = 150 ft
Designer: WILDEMAN, DENNIS D

Job Desc: CUST WANTS TO BUILD A NEW HOME 900+ FEET BACK FROM ROAD. APPROX. LOC ACROSS FROM ADDRESS 2497. CUST WILL CALL DENNY W. FOR

3.0 Costs of Extending Electrical Service

In response to concerns from the public and reported average extension cost estimates of $9,200 per extension, APS and TEP have prepared extension estimates for various property conditions. The following estimates have been obtained with a map illustrating distances from existing electrical facilities to new customer properties.

3.1 Arizona Public Service

In recent settlement documents, APS submitted extension estimates for certain distances both above ground and underground. The following is taken from those documents:

1000 ft. Overhead with 25 kVA transformer:	$19,400
750 ft. Overhead with 25 kVA transformer:	$18,500
500 ft. Overhead with 25 kVA transformer:	$14,000
1000 ft. Underground with 25 kVA transformer:	$10,900
750 ft. Underground with 25 kVA transformer:	$9,900
500 ft. Underground with 25 kVA transformer:	$9,000
Residential metro subdivision: $2,300 per lot	
Underground customer provides trench, conduit, and backfill.	

While the average cost of extensions over the last few years has been calculated at $9,200, it is evident that there is a wide range of potential costs.

Single Residential Lot Estimates

The following are actual estimates produced by APS for various properties in the Buckeye area. The estimates are provided in full in an appendix at the end of this report. Maps of the properties have been included showing the parcel, existing APS power lines, and the approximate distance from power lines to the property.

Testimony of Joel N. Lawson Jr.
In Opposition of Settlement Agreement
Arizona Public Service Company Docket No. E-01345A-08-0172

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Joel N. Lawson Jr. I am the Principal Owner of Integrity Realty & Assoc, L.L.C. Our Offices are located at 8511 Concho Highway & 110 North Main St. Snowflake , Arizona , 85937

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE?

A. I am the principal owner and designated broker of Integrity Realty & Assoc, L.L.C, I have served several years on the board of directors of the White Mountain Association of Realtors and currently serve as President Elect. I have completed a course in appraisals with the Appraisal Institute at Arizona State University . I have served several years on the Navajo County Planning & Zoning Commission and am currently the Vice Chairman for the Commission. I have sold or been the broker supervising over 1000 escrows in rural Arizona .

Integrity Realty & Assoc, L.L.C. has vast experience in working with power utility Companies in the extension of power to properties in rural areas. We often sell property that is from a couple of feet to a several miles from power.

Q. WHAT INTEREST DOES INTEGRITY REALTY & ASSOC. LLC & JOEL LAWSON HAVE IN THIS DOCKET?

A. We are often asked what buyers can expect, concerning the cost of extending power for domestic use, or if they can realistically expect to obtain grid power at a reasonable or practical price. Instead of answering directly we refer them to the utility company (APS), where the have been told recently that they must pay $500.00 non-refundable in order to even be given an answer. As a company we have seen many property owners have their property devalued due to the current policy that, APS the Corporation Commission and other utility companies have adopted eliminating the 1000' free power extension. What use to be a part of customer service at no charge, can now cost $15,000 to $20,000.

This means that large groups of property owners who previously bought property believing that they could extend power at little or no cost, now have property they can not afford to build on, due to the cost of power.

As a citizen of our state I believe this policy will stop development especially for the individual and add $15,000 to $20,000 to the price of any home built by a developer. Although the developer will be less impacted because they can spread the cost a little and will just pass the cost on to the buyers of their product. Devalued land means lower taxes as prices drop or value disappears altogether.. Is our state prepared to have property values drop drastically in all rural areas of the State and suffer the reduction in revenue it will surely create.

EXHIBIT
P-9
ADMITTED

This disproportionately affects those in rural areas. Those in rural areas do not have the developer interest in their areas that large cities do. This also greatly affects those who might have property that they had planned to provide to their children for homes. This property will no longer be of value to their children due to the cost of extending power even a short distance.

Although I am sure in the hearing where APS made its case for doing away with this free power extension they claimed it would help them avoid rate increases. Is it not true that from that time, they have already been back 3 times for higher rates so It appears it did not avoid rate increases.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. YES.

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED

2009 JUL 29 P 1:31

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 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 In Opposition to the Proposed Settlement Agreement

Pursuant to the Procedural Order issued by the Arizona Corporation Commission on May 11, 2009, Barbara Wyllie-Pecora files the Direct Settlement Testimony of the following witness in opposition to the Proposed Settlement Agreement dated June 12, 2009:

1. Carl R. Faulkner

RESPECTFULLY SUBMITTED this 29th day of July, 2009,

BARBARA WYLLIE-PECORA
Intervener

By Barbara Wyllie-Pecora
Barbara Wyllie-Pecora

ORIGINAL AND 13 COPIES OF THE FOREGOING filed this 29th day of July 2009 with:

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

EXHIBIT
R-10
ADMITTED

Q. Please state your name. address and employer.

A. Carl Faulkner. 4109 Washington Avenue. Douglas. Arizona 85607. Sonora Development, LC. We are a land developer and general contractor company.

Q. Please describe the nature of your responsibilities there.

A. I am a managing member of Sonora Development. LC. I supervise the Arizona projects of our company.

Q. Please state the number of years you have been in the development and construction business.

A. I have been involved in construction for nearly 40 years. Our companies have developed and built residential and commercial product. including: single and multi-family residential developments. class A and B office developments. warehouses, a golf course. hotel. medical facilities, etc.

Q. Can you explain. from your experience as a Builder and Land Developer. the impact on development of the current "Service Schedule 3 Conditions Governing Extensions of Electric Distribution Lines and Services"?

A. The immediate and most obvious impact to development of the Schedule 3 policy changes is that it is limiting growth. More precisely. the current Schedule 3 policy harms land development and new construction in general and specifically adversely impacts rural Arizona because of poor market conditions. sparse population and distances from electric power services.

Q. Can you elaborate on the impact you see which results from the current Schedule 3 policy?

A. I would like to address just four issues in which the current Schedule 3 policy have adversely impacted our company and have and will adversely impact the public in general.

First. the approval of the current Schedule 3 policy. by design or by chance. has expanded what I believe to be an unregulated monopoly which appears to violate Federal Anti-trust Laws. I am no attorney but it seems clear that this is contrary to existing anti-trust laws. Under the provisions of Schedule 3 this monopoly is not regulated in its daily operations and activities, and APS may to

do whatever it deems is in its best self interest relating to the installation and upgrading of their facilities. Paragraph two of Schedule 3 states. "***All extensions*** shall be made in accordance with good utility construction practices. ***as determined by (APS), and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company...***" Since APS determines what schedule, materials and labor for all line extensions, the builder/customer is at the mercy of APS to install facilities in a timely manner at the most reasonable costs. It is absurd to believe that APS, a company for profit, will give more than a "passing glance" at costs when they do not have to pay them. Of course they want their facilities state of the art and upgraded at there will. There are no competitive material and labor bids, there is no competitive contractor who is allowed to do the construction of the facilities – only APS construction crews which are paid APS wages, using constantly upgraded equipment as determined by APS at their sole discretion, etc.

Sonora Development, LC is licensed in Arizona to perform much of the labor required for the installation of APS Facilities. We can provide comparable equipment and materials at a significantly lower cost than APS but under this policy we have no option but to pay more for all of the costs associated with the installation of their facilities. We must wait for APS to put us on their schedule which they assure us will be timely. I have been waiting two months to get a transformer raised to ground level. They continue to tell us that they need to send a technician out to investigate it. We did have one arrive but they say that they need to send another one. I am helplessly at their mercy. We provide the entire delivery system to APS free of all costs so they can make more profit on the power they provide to the public. And, we have no alternative or means to provide alternative power to our customers. You can be assured that the costs of materials will also rise under this Schedule 3.

Second, Schedule 3 continues, "...***All payments received for new or upgraded service under provisions of this schedule shall be non-refundable.***" (A.C.C. No. 5695 canceling A.C.C. No. 5683; Service Schedule 3 Revision No. 10 Effective: February 27, 2008). It is outrageous to believe that it is fair or right to allow APS to receive free of costs all of their facilities. Wouldn't we all love to have all of our delivery costs prepaid by others. Developers under the previous Line Extension Policy could reasonably afford the risk and cost of money to pre-pay the Line Extension costs in their development expecting reimbursement for this investment when we bring new APS customers to hook up to their power. This policy removed the risk of new Line Extensions from APS because they did not reimburse the Developer until and unless the houses were sold and new customers hooked up. Even if the developer lost his property through poor judgment or circumstances beyond his control, APS owns the facilities and the easements to maintain them and without the obligation to repay the developer.

Third, it has been stated that the intent of the ACC and APS is that "growth pays for growth". However, Schedule 3 kills growth because it unfairly burdens the developer with addition costs and risk. In a marginal or depressed market such as we find today there is no market that can bear this burden. It is especially impactive in rural Arizona where there is no market for new housing and a few home buyers can qualify for a mortgage with these additional costs. Rural land costs will of necessity plummet because no one will want to pay the added cost or chance that APS will find "...***adequate capacity, voltage and Company facilities...***" to bring power to their property. We own nearly two hundred acres of rural land which has been devalued by this egregious policy. We have terminated operations and had to lay off construction crews because the market cannot afford the added cost of housing created by this policy. We have invested nearly $5 million in offsite and onsite improvements, including utilities. We brought the Power facilities at our expense to our site expecting reimbursement under the old policy. Some lots have not sold to date

and APS has not had to pay anything for their facilities to these lots. Phase two of our development has forty-three lots. APS quoted me $98.000 or $2300 per lot in this phase. We have thirty-five lots which were scheduled to have smaller affordable housing to meet the needs of the local market. Again, the buyers would be NEW CUSTOMERS BROUGHT TO APS without risk or costs – this is GROWTH PAYING FOR GROWTH. We even give APS, free of charge, a utility easement to maintain these facilities on property we have paid for and must pledge to utility services. However, these houses are now out of reach for these potential new home buyers – they simply do not qualify for the loans. We had planned several more phases as the market improved but we have been forced to shut down because of the Schedule 3 policy changes.

Fourth, regarding the loss of the free 1,000' Line Extension, I have a man who asked me to build him a home on an "in-field" lot measuring 25' X 110' which he bought for about $3000. In checking with an APS engineer about the cost to provide power to this existing improved lot within the City of Douglas, I was told "if the transformer was outdated they would require a new one at a cost of $6000 and a connection fee of $1300. The cost of the power exceeds the value of the lot by more than double. He abandoned the idea of building a house on this property and the property has been devalued. The market simply cannot pay an additional $7300. The City has at least a hundred such lots like this one which are eyesores and must be cleaned and weeded every year by city maintenance crews at a significant cost to the city. The owners are abandoning their lots and not paying the taxes on them. The American dream of owning your own home continues to get out of reach because of accelerating costs of construction and egregious policies such as the current Schedule 3. The Federal government has been attempting many measures to stimulate growth in our economy. The majority of economists agree until housing is restored our economy will not improve and yet this policy has been approved which is the antithesis of such economic improvement.

Q Do you see any solutions to reverse the negative effects of this policy?

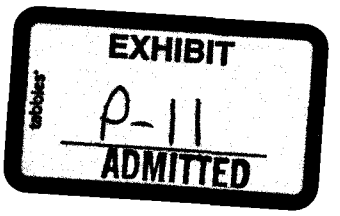
A The only valid and fair solution is to reverse the schedule 3 policy decision and restore what has been lost so that growth continues even in this difficult economic times. This reversal ought to be retroactive to the date of implementation.

The additional cost of power upon the reinstatement of the previous Schedule 3 policy across the APS service area will be minimal in comparison to having an unregulated monopoly determine the costs of facilities which the public is then obliged to bear; or, to kill housing and new development because builder's no longer can afford the risk and investment associated with improving land: or, having growth pay for the growth of APS rather than the growth of our economy: and finally, the additional cost of power upon the public by reinstating the old policy is minimal in comparison to the urban squalor that comes from lots which are no longer worth improving because of the costs of electrical facilities to service them. The public will actually bear the additional costs associated with this policy in higher taxes for cities to maintain these blighted properties. I respectfully urge the commission to do the right thing and reverse this policy.

Q. Does this conclude your testimony?

A. Yes. but I wish to express appreciation to the commission for allowing me to voice the grave nature and impact of this policy.

Testimony of Gary T. Nelson
In Opposition of Settlement Agreement
Arizona Public Service Company Docket No. E-01345A-08-0172



Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS BACKGROUND.

A. Gary T. Nelson. I am an Associate Broker with Realty Executives of Flagstaff. My office is located at 15 E. Cherry Avenue, Suite 101, Flagstaff, AZ 86001. Additionally, I am a Regional Vice-President of The Arizona Association of Realtors.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I attended Northern Arizona University from 1985 through 1989 in Civil and Mechanical Engineering. I have been a licensed real estate agent since November of 1994. I obtained my real estate Broker's license in 1998.

I have served as President of the Northern Arizona Association of Realtors in 2001. I have been a member of the Board of Directors the Arizona Association of Realtors from 2002 to present. Additionally, I served on the Board of Directors of the National Association of Realtors from 2002 through 2008.

Q. WHAT IS YOUR INTEREST IN THIS DOCKET?

A. As a real estate broker serving areas of rural Arizona, I have experience in representing clients in the purchase and sale of rural property. Vast areas of Arizona are not serviced by utilities, of which the most important is electricity. With electric service to a parcel or area, most common living attributes are obtainable. Lighting, heat, cooking and internet access are only a few of these. Without electricity, most of these common living necessities are either difficult or impossible to obtain.

Northern Arizona has a far greater challenge than other areas of the state for obtaining electric service. With only 17% of available land being privately owned, vast areas are either federal or state lands and are not served by utility companies. Electric service just is not available.

However, many areas do have service readily available and nearby. Connecting to that service is costly and greatly impacts citizens' abilities to obtain service, if at all. Huge tracts of Northern Arizona are dedicated as Reservation lands. The effect of not providing utilities to is readily noticeable. Without power, families have no lighting, heating from potentially dangerous sources, no internet connection, much less a lack of conveniences that most of us take for granted.

The move to eliminate no-cost electrical service extensions to residential lots and subdivisions will be astronomical. By bearing the cost of installing service to a parcel where service is nearby, few citizens will be able to obtain that service. Many see the elimination of service as an attempt to limit growth and "sprawl" in rural areas. However, these parcels are and will

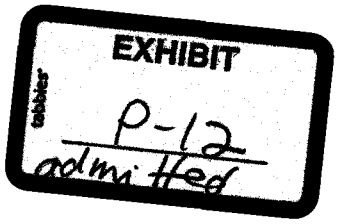
continue to be in private hands. They will be inhabited. But basic services will not be available. The owners or tenants of these properties will then live without many necessities, many living in squalor.

Arizona is and will continue to be a rural state. We are still "catching up" with the idea that utilities are a basic right for citizens and a service that government provides to its citizens and "catching up" with actually providing those services to the rural citizenry. To remove the ability of many of its citizens to obtain basic services challenges the duty of that government to its citizens. As a Commission, your duties are to the citizens of the State of Arizona. Providing basic living necessities is one of society's biggest challenges. In a rural state such as Arizona, the challenge is bigger and it is imperative.

I ask that the move to eliminate no-cost electrical service extensions to residential lots and subdivisions be denied. As a rural state, Arizona will be abandoning a basic service to its citizens and I ask that you, as a Commission continue to provide a 1000 utility extension onto private property.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.



Q Please state your name, address, and employer.

A Bobby Miller, 22422 N. 80th Lane, Peoria, AZ 85383 WEST USA Realty for 20 years

Q Please describe the nature of your responsibilities there.

A I have been an independent contractor specializing in land sales brokerage.

Q Please state the number of years you have been selling land.

A I began selling land in 1977, 32 years ago with Unique Real Estate and have exclusively made my living selling land ever since.

Q Could you please give a general summary of the volume of land you have sold?

A I have sold over 1000 individual transactions between buyers and sellers in arm's-length transactions with a dollar volume well over 200 Million dollars in closed transactions.

Q Would you say you work more with individuals or corporations?

A My first love is working with individuals but I have represented business entities, developers, and some of the largest corporations in the world during my tenure.

Q Have you any experience in selling rural properties?

A I have a great deal of experience in representing individuals seeking the rural lifestyle for the benefits it offers – primarily peace & quiet, lack of HOA governance, reduced prices, etc.

Q Could you describe the value of the 1000 ft free policy over the years?

A This policy had been the backbone of rural development. It has afforded hundreds of thousands of property owners the opportunity to improve and occupy otherwise unimproved properties. It would be virtually impossible to quantify the impact this policy has had in the development of much of rural Arizona today. It made most rural development possible where it otherwise would financially be beyond the reach of 99% of today's property owners.

Q Could you describe the effect removal of this policy has had?

A Rural land sales have all but come to a complete stand-still since this policy change has been put into effect. It's sad to say but many of the sales that have taken place since the policy change have happened without the knowledge of the purchasers. Lives have been devastated as a result of so very many properties that have been purchased with the

dream of getting away to the rural settings only to find that dream has now been put so far out of reach due to the cost of power extension. Not only that, but properties previously well within the immediate reach of power due to neighboring properties' improvements now find the expense of simply hooking up to the existing power supplies require such an expense that it completely eliminates any possibility of improving the properties for occupancy. This policy change has enormous – far reaching implications as well to future development and growth of our communities and beyond.

Q Could you see an adverse effect down the road due to the removal of this 1000' free?

A Absolutely! There are literally hundreds of thousands of property owners directly affected by this policy change in an extremely negative way. In too many cases this now doubles the cost of development, or even worse in some instances.

Q Do you believe it will have an effect to rural property owners exclusively?

A Not at all! Over the years, developers have customarily gravitated to areas of town where the rural development was active. Case-in-point, Anthem is one of the most prestigious development communities in our State and the Del Webb company specifically chose to launch this great community development as a direct result of the success of both the Desert Hills rural area and the rural community of New River. It's these rural communities that many times paved the way for the large developer. Vistancia, Tramonto, Verrado, Troon, and a myriad of other extremely desirable/successful developments came on the heels of the neighboring rural communities success. Without this rural development keeping an active pace, we could see the devastation of our current growth and planning systems. It's what has kept Arizona such an attractive landing spot for a migrating people.

Q Will there be collateral effects due to this policy change?

A Absolutely! Right within the APS company, their own technicians that stayed quite busy installing these power extensions in times past are certain to see a continued reduction in work force. The entire construction industry will suffer due to the lack of development. The trickle-down effect has already negatively impacted the real estate industry, mortgage and banking industries, appraisers, etc. on down to the very municipalities and government entities that received revenues from such. The effects of this policy will even affect our own property taxes in the long run.

Q How far reaching could this effect go?

A The municipal and State governments will be so impacted that major changes will be required to feed their machines (so to speak) where the ongoing development used to pay it's own way at a very handsome pace.

Q Do you feel this policy has had a negative effect on the value of State Trust Land as well?

A Absolutely! When property is appraised, it will be impossible to ignore the negative affect this policy has had on all property – private and pubic lands. State trust lands have provided a substantial amount of funding to our State's economy and that value is now diminished greatly. Without this income, the State will have to increase taxation to compensate as I seriously doubt they intend to dramatically reduce the size of the government itself. We, the existing homeowners will have to pick up the slack for the loss of revenue and, believe you me, they will lose millions and millions of dollars of revenue from the dramatic land value reduction this policy had created. I know of few of my past customers who are not prepared to fight for a giant reduction in assessed value this coming year when the County Assessor sends out the new valuations. These land owners are clearly aware of the negative impact not having affordable power has had on their land and they intend to step up in a very large way to demonstrate it with this upcoming assessment.

Q Do you see any solutions to reverse the negative effects of this policy change?

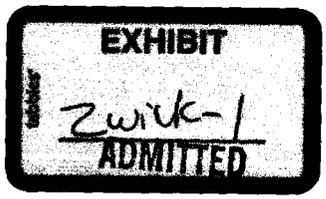
A Without the complete reinstatement of this 1000' foot free policy, I see nothing.

Q In your professional opinion, what would you like to see?

A Without hesitation, I see the only possible solution being the complete reinstatement of this policy as it once stood. The cost, when averaged across the entire spectrum of APS customers, would be minimal in contrast to the increased taxation they would experience. Add the loss of revenue to the State, County and municipalities as well as the economic impact this is having on those affected by the lack of development, all the way from upper-management professionals on down to day laborers and everything in between which represents much of Arizona's vital economy and the solution is crystal clear. I respectfully submit the only possible answer is the complete reinstatement of this 1000' free policy as it once was so our entire State can benefit.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS



MIKE GLEASON, Chairman

WILLIAM A. MUNDELL

JEFF HATCH-MILLER

KRISTIN K. MAYES

GARY PIERCE

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

DIRECT TESTIMONY OF CYNTHIA ZWICK

State your name and address.

My name is Cynthia Zwick and my address is 1940 E. Luke Avenue, Phoenix, AZ 85016.

Q. What is the purpose of your testimony?

A. I am testifying for several purposes: 1) to urge the Commission to hold low-income residential customers harmless in this rate case, as was requested by the Company in the Interim rate case; 2) to urge the Commission to increase the E-3 and E-4 discounts to an amount commensurate with any residential rate increase the Company may be awarded; 3) to modify the E-3, E-4 and bill assistance and weatherization program language to track the LIHEAP eligibility criteria; 4) to increase the number of customers

participating in the E-3 and E-4 discount programs; 5) that APS modify its policy related to the assessment of deposits for delinquent customers, specifically customers enrolled in the E-3 and E-4 rates; and 6) to increase the marketing of, and thereby the enrollment in the E-3 and E-4 discount programs.

Q. What is your experience with low-income issues?

A. I am employed as a low-income advocate, a position I have held since 2003, and have intervened in a number of rate cases in order to ensure that the interests and impact of rate increases on the low-income community are heard and appreciated.

Q. Would you please describe the low-income community in Arizona?

A. A year or two ago, my answer would have been a bit different than today, however, the definition of a person living in poverty is an individual earning $10,400 or less annually, or a family of four earning $21,200 or less annually. For purposes of this testimony I will be referencing families living at 150% of poverty, because most of the programs assisting low-income families have established this baseline eligibility. At 150% of poverty, an individual earns $15,600 annually and a family of four, $31,800.

According to the 2007 U.S. Census Bureau data, in Arizona today, there are 858,973 individuals living at 100% of poverty or below, or 14.2% of the total Arizona population. At 150% of poverty, there are approximately 1,083,801 individuals, or 17% of the population.

The reason I state above that my answer would have been different a year ago, is that due to the failing economy, the number of families that are finding themselves in need of assistance is growing daily, and the face of poverty is changing in Arizona. These numbers are not as easily quantifiable, but they are no less disturbing.

Q. What is the extent of poverty in the APS service territory?

A. According to the 2007 census, there were 6,100,000 people living in Arizona, 1,083,801 of which were living at 150% of the federal poverty level. By APS service territory and by county these numbers break down as follows:

County	# of people at 150% poverty
Cochise	32,497
Coconino	33,219
Gila	15,508
La Paz	6,808
Maricopa	615,279
Navajo	41,418
Pima	203,574
Pinal	45,590
Yavapai	37,124
Yuma	52,784

Q. Can you explain in what manner the current State economy is affecting our community, and therefore the APS rate payer?

A. There are new reports in the local and national media every day articulating the depth and breadth of the problems related to a failing State and Federal economy. The Arizona Republic reported on December 11, 2008 that, "Arizona's economy is in the worst shape of any state in the West – and its job market has seen the second-largest losses in the nation, behind Rhode Island – because of major overbuilding of homes in 2005-2006 and weak job growth today," according to Lee McPheters, an economics professor and director of JPMorgan Chase Economic Outlook Center at Arizona State University.[1]

According to Arizona Department of Commerce website (www.workforceaz.gov) unemployment in Arizona in October 2008 is 6.1%, compared to 3.7% in September 2007, Arizona having lost 59,200 jobs during that time period. In November 2008,

[1] The Arizona Republic, November 11, 2008, "Economic Forecast: Long, slow recover."

unemployment insurance applications averaged 9200 a week, with a high in November during the week of November 17th, of 11,502 applications.[2]

Requests for child care assistance are up 5.4%, with the median cost for child care ranging from $463 per month for pre-school aged children and older to $737 a month for children under the age of one year. One in five Arizonans lacked health insurance coverage for at least some portion of 2008. For working adults between the ages of 18 and 64, the number goes up to 25%.[3]

According to the U.S. Conference of Mayors 2008 Status Report on Hunger & Homelessness,[4] during the last year, the number of requests for food assistance in Arizona has increased 35%. "Providers are reporting a significant increase in the number of new persons seeking assistance, especially among working individuals and families. Moreover, there has been an increase in the frequency with which persons access food assistance programs." The Food Research and Action Center reports that food insecurity, or the inability to provide sufficient amounts of food for your family, was 12% in Arizona on average, between 2005-2007 (18th in the country), with very low food security at 4.6% (14th in the country.)[5]

Utilities in Arizona are also seeing an increase in the number of customers seeking assistance, as well as the number of customers being disconnected. APS executive staff reported a 40% increase in the number of credit arrangements being made with customers, a 14% increase in the number of door hangers being left for customers, a 7.2% increase in the number of disconnections during the first nine months of the year for a total of 45,000 disconnections through September 2008. Of the customers that have their electricity turned off, 55% are reconnected. The Company states those customers may come back, but those accounts will ultimately go into the closed account collection process, and may eventually be written off, fuelling future rate increases.

---

[2] Arizona Republic, November 8, 2008, "Surge in Arizona unemployment claims delaying benefits."
[3] PAFCO Annual Meeting Presentation, December 2, 2008
[4] U.S. Conference of Mayors 2008 Status Report on Hunger & Homelessness
[5] Food Research and Action Center (FRAC) State of the States 2008, www.frac.org, Arizona

The Community Action Agencies which provide the direct bill assistance support to households throughout the State are seeing increases as high as 60% in the number of families seeking assistance. One community action agency reports that in the month of August 2008, their Family Service Centers received 15,835 calls for assistance. This number does not include calls that did not get through the automated phone system. Of the 15,835 calls, 12,709 requested an appointment. Of the 12,709, 1,034 households received appointments, and of those, due to available resources, 248 received help with their utilities. Another 144 received emergency appointments, which could have included utility assistance. Another rural community action agency turned away 5734 families between July and November 2008, many of whom were seeking utility assistance. During the summer months when utility bills are at their highest, this Agency was receiving as many as 20 crisis calls a day from families in imminent danger of the loss of utility service.

This volume is reflective of all Agencies providing bill assistance throughout Arizona. The need far exceeds available resources.

Q. Arizona recently received additional LIHEAP funding. Will that take care of the problem for families?

A. No, unfortunately it will not. During federal fiscal year 2008, Arizona received a total of $6.1 million dollars in LIHEAP funding. In November, 2008 we received notice that Arizona would be receiving $31 million in federal LIHEAP dollars. Arizona continues to be the least funded per capita of any state in the country, so even though we received a significant increase in funding, out of an eligible population of approximately 500,000 households, agencies anticipate being able to serve an additional 50,000 households for a total number of households served of 78,000. This represents an ability to serve approximately 16% of the eligible households.

Finally, throughout Arizona, the increased number of calls and the increased number of families seeking assistance has changed. While there is a certain demographic that needs

support on an ongoing basis, the very low income community, the new demand has been created by families who for the first time in their lives are seeking help. The majority of the increase in calls and requests for help are coming from families who have never asked for or received help before. Due to circumstances in their lives, losing their jobs, losing their homes, experiencing an illness in their family without adequate insurance coverage along with the rising cost of services, more families have been forced to seek help in order to feed their families.

Q. Have customers commented in this case about the requested increase?

A. Yes, in fact there are a large number of customer comments that have been filed in this case – 307 comments as of this filing. After reviewing them, there are a couple of trends that emerge. Seventy-one customers indicated that a rate increase now doesn't feel justified with the economy as it is. Ninety-two customers indicate they can't afford their bills and encourage APS to cut their waste to save money. Another thirty-four customers indicate it's difficult for customers on fixed incomes to pay their electric bill. Several of the customer comments are attached to this testimony for review.

Q. Are there other options for serving more low-income APS customers?

A. Yes. When the State received the additional LIHEAP funding, the community action agencies and State Department of Economic Security staff, agreed to increase the eligibility for these funds to 200% of poverty from 150% of poverty. This was done to be able to serve more families in need of assistance but who would be turned away if they did not meet the lower income threshold. This was also done in order to respond to the significantly increased need being experienced throughout Arizona, and is consistent with federal legislation. I would like to see the income eligibility language for the E-3 and E-4 discounts, as well as the Bill Assistance and Weatherization programs track the LIHEAP eligibility language so that as the need increases and funding is available, more families may receive the help they so desperately need.

Q. What is the specific language you would like to see used?

A. The language in each program or rate could simply state, "customers meeting the LIHEAP income eligibility are also eligible for the APS E-3 and E-4 discounts, Bill Assistance and Weatherization programs."

Q. What is the current enrollment in APS' E-3 discount program?

A. There are currently 48,708 customers enrolled in the E-3 discount rate. If we use the current poverty data for the state, and recognize that there are 14.2% of Arizonans living in poverty, it would follow that of the approximately 966,013 APS customers, 137,000 customers are eligible for the discount program.

Q. Is the number of E-3 enrolled customers higher or lower than past years?

A. There are significantly more customers enrolled in the E-3 discount program this year. The average number of customers enrolled in the E-3 discount program in 2005 was 25,602 a month, 36,469 in 2006, 44,195 in 2007 and in the first ten months of 2008, 46,825 customers.

Q. What can the Arizona Corporation Commission do to increase enrollment in the E-3 and E-4 discount rates?

A. There are two things that can be done. First, the Commission may require enhanced outreach and enrollment programs, making the availability of these programs much more visible to the target customer base.

The second thing that may be done is to create an automatic enrollment program for all customers receiving LIHEAP, Utility, Repair Replacement and Deposit and/or Home Energy Assistance Funds. All of these programs share an income eligibility standard and are easy to track within a system.

Q. Are there other actions that could be taken to increase awareness and enrollment in the discount programs?

A. Additional outreach or marketing to customers about the availability of the discount programs would definitely help. Targeted marketing to customers living in specific zip codes that have been determined to fit the "low-income" demographic, public service announcements on the radio, in newspapers and even on TV would help increase awareness about the availability of these important programs.

Q. Is there any reason APS management would be opposed to the automatic enrollment requirement for the customers eligible for the programs listed above.

A. APS management may object to the significant increase in enrollment because increased enrollment will likely result in the company being required to underwrite the savings realized unless there is a mechanism created within the rate structure that would allow for the recovery of the realized savings on an ongoing basis. While I believe the Company should be able to bear a portion of the savings to the low-income family, I also believe that an ability to recover these costs through rates is reasonable.

Q. Does APS receive funding from other sources to assist customers with their APS bills, and if so from what sources?

A. Yes, in fact APS received approximately $2,380,918 in bill assistance and deposit payments from just the community action agencies during SFY 2008. Approximately $209,452 of this money was from its own bill assistance program.

The funding flows to APS from LIHEAP, Home Energy Assistance funds, and URRD funds. Additionally, and not included in the $2,380,918 amount already mentioned, funding flows to APS from customer contributions, or SHARE funds that are administered by the Salvation Army, and private donations that are administered by St. Vincent de Paul.

Q. You have indicated that you are also asking APS to modify its deposit policy for delinquent customers enrolled in the E-3 and E-4 discount programs. Why is this important?

A. The only customers enrolled in these two rate classes are low-income customers. If they become two or three months delinquent on their bills, it is most likely that it is because their expenses exceed their income, and they are making choices about what bills to pay. Assessing a deposit that is two times their average bill, and if their power is disconnected assessing a $75 reconnect fee, only puts that customer further behind and makes it impossible for payment to be made in order to prevent disconnection or restore power. Charging a family who cannot pay a bill more to maintain or restore service is not only counterintuitive, it is totally impractical.

Q. Would you summarize what you are asking the Commission to approve in this case?

A. Yes. Raising the rates on a class of customers who cannot pay their bills today, makes no practical sense for the customers or for the Company. As previously stated, I am requesting the following actions be taken. I am asking that the Commission: hold low-income residential customers harmless in this rate case; increase the E-3 and E-4 discounts to an amount commensurate with any residential rate increase the Company may be awarded; the discount and program eligibility language be modified to track the LIHEAP eligibility language and criteria; to provide meaningful increases in enrollment in the E-3 and E-4 discount programs among eligible customers; modify the deposit policy currently in place for customers currently enrolled and those who enroll in the discount programs in the future so that customers who become delinquent and are threatened with disconnections are provided a meaningful opportunity to pay their bills and avoid disconnection; and the increase the marketing of the discount programs among customers in order to increase participation.

Q. Does this conclude your testimony?

A. Yes it does, thank you.

Attachments

1. "Economic forecast: Long, slow recovery," Betty Beard, Arizona Republic, November 11, 2008
2. "Surge in Arizona unemployment claims delaying benefits," Craig Harris, Arizona Republic, November 8, 2008
3. PAFCO Community Meeting Presentation
4. U.S. Conference of Mayors, 2008 Status Report on Hunger & Homelessness
5. Food Research and Action Center, State of States 2008, Arizona
6. Food Research and Action Center, Prevalence of Household-Level Food Insecurity and Very Low Food Security by State, 2005-2007, November 17, 2008
7. Customer Comments:

   Claudia Matanyi

   Constance A. Nuzzi

   Dottie Martin
8. Cynthia Zwick Vitae

Experts meet in Valley, say 2009 may be start of recovery

42 commentsby **Betty Beard** - Dec. 11, 2008 12:00 AM
The Arizona Republic

The state's economic slide will continue through the new year. A turnaround could begin sometime in 2009. Consumers, weary of living on edge, will start spending again. But how long until a full recovery? It may not come until 2011 or 2012.

That's one view of the future, at least, from the experts who offered their annual economic outlook Wednesday at the Phoenix Convention Center.

Other key findings and predictions:

• The recession is "extraordinarily deep and extraordinarily widespread," the most dangerous since the 1920s, said Joel Naroff, a Philadelphia economic forecaster.

• Arizona's economy is in the worst shape of any state in the West - and its job market has seen the second-largest losses in the nation, behind Rhode Island - because of major overbuilding of homes in 2005-06 and weak job growth today, said Lee McPheters, an economics professor and director of the JPMorgan Chase Economic Outlook Center at Arizona State University.

• Still, this downturn isn't expected to become a full-on depression, said Rajnish Mehra, E.N. Basha Arizona Chair at ASU and a widely published economics expert. A lot of it is being driven by self-fulfilling fear, he added.

At last year's Economic Forecast Lunch, also sponsored by JPMorgan Chase and ASU's W.P. Carey School of Business, experts had dour predictions for 2008, but no one knew then how bad things would get. This year, experts said they had been surprised at how quickly things worsened, especially after September's financial panic and subsequent credit freeze.

And although experts offered glimmers of hope for a recovery, they noted that the slide hasn't stopped yet.

"The economy is deteriorating very, very rapidly," McPheters said. "Our forecasts have been changing every month."

But Naroff, who has been honored by Bloomberg Business News, *USA Today* and ASU for being especially accurate, is more optimistic than many forecasters.

He said that because of falling energy prices, federal actions taken to calm the financial markets and President-elect Barack Obama's proposed stimulus package, the economy will show gains next year. And, at some point, consumers will get tired of being afraid and begin to spend again.

Mehra said that when he looked at recessions over the decades, each recession has been shorter and each expansion longer than the one before. Also, over the long term, the national gross domestic product has steadily improved. So, 2009 is unlikely to be like 1929, he said.

Jobs

Arizona's job numbers have been falling monthly through most of the year. The latest job numbers, down 2.8 percent from a year ago, are the worst since 1976, McPheters said. He expects no growth in jobs next year.

The state went from being the nation's No. 1 job creator in 2006 to 49th this year, according to the U.S. Bureau of Labor Statistics.

Arizona's unemployment rate, which reached 6.1 percent in November, is likely to rise to at least 7 percent, McPheters said. But it has been worse, reaching 10 percent in 1976 and 1982.

The construction industry is expected to lose about 80,000 jobs, or about one-third, from its peak in 2006 by the end of next year. The brightest spot is that health care is gaining about 1,000 jobs a month, McPheters said.

Real estate

The residential-housing market probably will recover faster than other real-estate sectors, such as office, industrial and retail, Scottsdale economist Elliott Pollack said. But the housing market is still three to four years away from full recovery, he said.

The problem is that there was a surplus of single-family homes built in 2005 and 2006 and there aren't enough people moving to the state, enough jobs being created or enough people confident enough to buy new homes.

Pollack estimates metro Phoenix has a housing surplus of 40,000 to 50,000. Tucson and Prescott also are suffering from an oversupply of homes, but the rest of the state is not, he said.

"My guess is that the residential market is not going to reach normal until 2012," he said.

At the same time the Valley is coping with too many houses, Arizona Public Service Co. has reported its lowest number of residential hookups since it began keeping records in the 1950s, an indication that in-migration has slowed dramatically.

Construction of offices, industrial buildings, apartments and retail space also has outpaced the demand, and construction is likely to slow down if not stop in a year or two, he said.

Retail

Naroff said the lack of consumer confidence and spending is now a more serious problem than the ailing housing market. Consumer spending accounts for about two-thirds of the country's economy.

The Arizona Blue Chip Economic Forecast, a consensus of about 20 economic experts in the state, predicts retail sales will fall 3 percent this year in Arizona and increase only about 1 percent next year.

But eventually he and other experts expect that consumers will get tired of sacrificing and curtailing their purchases because of the dour economy.

"Once that psychology changes, I wouldn't be surprised in one year if growth will happen a lot faster than anyone expected," Naroff said.

December 15, 2008 | 12:42 pm | 54°

NEWS

News

Type Size: A A A

Print

Email

Most Popular

SHARE

Buzz up!

Surge in Ariz. unemployment claims delaying benefits

by Craig Harris - Nov. 8, 2008 12:00 AM
The Arizona Republic

Arizonans losing their jobs in the economic downturn will have to wait nearly a month instead of the usual 10 days to receive their first unemployment benefits because of the surge in applicants and a lack of workers to process claims.

Unemployment claims have been rising all year. The state last week received 9,144 first-time unemployment claims - up more than 125 percent from the roughly 4,000 first-time claims filed in the same week a year earlier.

Claims in September, the last full month for which data is available, rose 40 percent over the number of claims in September 2007.

The state Department of Economic Security, which administers the federal unemployment program, acknowledged the problem. Employees are working overtime, and plans call for the state to add positions to help process the claims.

"We are working as fast as we can," Liz Barker, a DES spokeswoman, said Friday. "Our staff is working two to four hours of overtime a day and sometimes on Saturdays to get claims processed."

On Friday, a phone glitch prevented residents from making claims most of the day, Barker said.

She encouraged residents to use the department's Internet site, www.azui.com, to make claims, although the phone system was working by Friday evening.

The DES tried to get weekly unemployment benefits, which are capped at $240 in Arizona, to residents within 10 business days, but it's now taking about four weeks.

Those who receive unemployment compensation through direct deposit in a bank account would receive several weeks of benefits in a lump sum if there is a delay, she said.

The DES will be adding eight employees during the next few weeks after hiring 70 in the past few months to handle additional claims, Barker said.

The new hires are exempt from the state's hiring freeze because funding comes from the federal government, she added.

Until more workers come on board, the delay is likely to continue as jobless claims continue to rise.

Experts say the unemployment rate in Arizona rose to 5.9 percent in September from 3.8 percent in September 2007 because of a struggling economy caused by a housing slowdown and sinking financial markets.

Arizona lost 59,200 jobs in that time, according to the U.S. Bureau of Labor Statistics.

In the same time span in metro Phoenix, the unemployment rate rose to 5.3 percent from 3.3 percent. Metro Phoenix lost 43,200 jobs from September 2007 to September

2008, according to federal statistics.

Nationally, the unemployment rate in October rose to 6.5 percent, up from 6.1 percent from the previous month, the Labor Department reported Friday.

State and local figures for October will be released in two weeks.

The country has lost 1.2 million jobs in the first 10 months of this year, while more than half the job losses occurred in the past three months, the government said.

Job losses were most severe in manufacturing, construction and service-related positions.

Some of the few bright spots were additional hires in mining and health care.

The federal unemployment rate is at its highest level since 1994. In Arizona, the highest unemployment rate in the past 30 years was 11.5 percent in February 1983, according to the state Commerce Department, which has predicted the state's economy won't improve until the end of 2009.

"When the federal economy tanks, it increases the demand for social services, which are administered at the state level," said Jeanine L'Ecuyer, a spokeswoman for Gov. Janet Napolitano. "The fondest wish would be that there be no wait at all, but we are not able to deliver."

Type Size: A A A
Print
Email
Most Popular
SHARE
Buzz up!

Valley woman helps unemployed get back in the workforce

more video »

More on this topic

Unemployment benefits

Who is eligible: Displaced Arizona workers whose employers were required to pay unemployment insurance tax. (Most employers do.)

Length of benefits:

Unemployed eligible workers typically receive up to 26 weeks of benefits, but Congress has extended that to

39 weeks.

Amount of benefits: Weekly benefits in Arizona range from $60 to $240 depending on wages when employed.

How to apply: To file for unemployment benefits, go to **www.azui.com** or call 602-364-2722.

Where does the money come from?: Unemployment-insurance benefits are paid from a fund accumulated from taxes paid by employers.

PAFCO Community Meeting Agenda

- Welcome and Introductions
- Current Situation as we know today
- Action Plans
- Closing

12/2/2008 PAFCO Community Meeting 1

PROTECTING ARIZONA'S FAMILY

- PAFCO is a non-profit coalition of health and human service agencies from all over Arizona.
- The Coalition was formed in 2001 to stop drastic budget cuts to health and human services and to promote health and human services funding.

www.pafcoalition.org

- ***Thanks to member contributions, St. Luke's Health Initiatives and the McMiles Foundation for funding PAFCO Education Fund Health Care for All and Citizen Advocacy Unfinished Agenda training project.***

12/2/2008 PAFCO Community Meeting 2

PAFCO

Principles

- Strength/power in our diversity
- Common Message
- Non partisan
- Not allowing groups to be pitted against one another

Actions

- State Legislative Budget Advocacy
- Unfinished Agenda of Need
- Health Care Reform Advocacy
- Federal Budget

12/2/2008 PAFCO Community Meeting 3

Environmental Scan – What's Happening in National – State Scene

- NATIONAL SCENE
  - Election of Barak Obama/Joe Biden
  - Democratic Majorities in House and Senate
  - National Recession/Economic Meltdown
  - Two Wars
  - Health Care Crisis
  - Crumbling Infrastructure
  - Energy Crisis and Costs – Climate Change
  - Federal Bailouts
- State/Local Scene
  - Severe Economic Recession – worse!
  - State Budget Crisis/Huge State Revenue Deficits/Local Government Budget Deficits
  - Conservative Majorities in House and Senate – New Leadership
  - Change in Governor with Election in two years
  - History of tax cuts limiting revenue

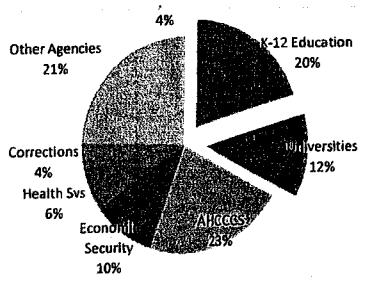
12/2/2008 PAFCO Community Meeting 4

Current Situation- State

- Special Session
- Transition to new Governor
- Changes in Legislature, committee chairs, and new members
- Loss of Champions in new legislature
- Huge Deficits with recession ongoing
- Inadequate Tax base
- Election in two years
- National bailout possibilities.
  - $500 million to $1 billion possibilities
  - Need to protect current programs and infrastructure so this is not diverted away from health and human services

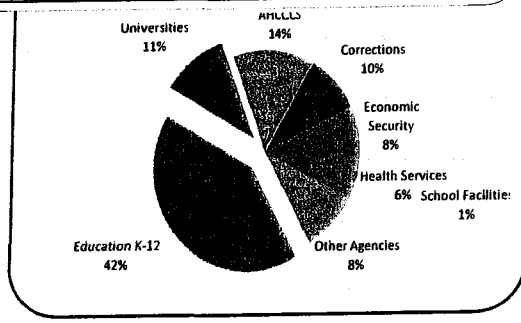
12/2/2008 PAFCO Community Meeting 5

Arizona's Total Spending



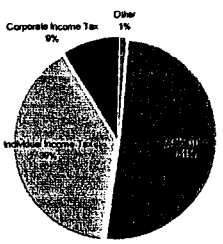
12/2/2008 PAFCO Community Meeting 6

General Fund Spending



12/2/2008 PAFCO Community Meeting 7

What is the General Fund?



Source: Arizona JLBC Appropriations Report *HIGHLIGHTS OF THE FY 2008*

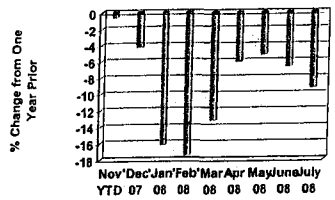
12/2/2008 PAFCO Community Meeting 8

What Kinds of Taxes are There?

- Arizona Ranks 34th in Overall Taxes (State/Local)
  - Sales taxes - make up 51% of the state's general fund – that's up 2% from last year.
  - Property taxes - collected and used by local governments such as counties, school districts, and cities. There are very few property tax dollars that go into the General Fund.
  - Income taxes – make up 48% of the general fund – 39% from individuals and 9% from corporations.

12/2/2008 PAFCO Community Meeting 9

Revenues Have Been Declining For Nearly a Year



Source: Joint Legislative Budget Committee staff

12/2/2008 PAFCO Community Meeting 10

CURRENT AND PROJECTED BUDGET DEFICITS How This Translates into $

- FY 08 shortfall grew from $970 million to $1.2 billion
- The FY 09 shortfall that was supposedly solved when the budget was put together was $1.2 TO 1.7 billion SHORT.
- Special Session will deal with part of 2009 up to about $350 million plus.

- 2010 Could be
- $2.3 to $3billion
  - Options list includes things like:
  - Eliminating Kidscare and Kidscare Parents
  - Reduce some optional services in AHCCCS
  - Reduce CPS family services
  - Reduce Children Support Services
  - Eliminate Ticket to work
  - Reduce DDD rate increases
  - Reduce Childcare eligibility
  - Eliminate GA
  - Eliminate funding for Community health centers
  - Eliminate Alzheimer's Research funding
  - The OPTIONS list for 2010 goes on and on.

12/2/2008 PAFCO Community Meeting 11

ASU Study - Hoffman-Rex report on tax cuts and economic impact.

"The tax reductions of the last 15 years have been the main cause of the structural deficit, which also is the result of an outdated tax code that creates large cyclical swings in revenue and that causes revenue to grow more slowly than the pace of the overall economy. Many of the changes to the tax code during the last 15 years exacerbated these problems.

- *Tax law changes since 1993 cumulate to a decline in general fund revenues of about $1.63 billion on a nominal basis and $2.58 billion after adjusting for inflation.*

12/2/2008 PAFCO Community Meeting 12

ASU Study - Hoffman-Rex report on tax cuts and economic impact.

"Thus, the existing state general fund budget deficit as well as the underlying structural deficit cannot be blamed on excessive spending.

Instead, very aggressive tax cuts are the primary cause, with other shortcomings in the revenue system — increasingly cyclical revenues and revenue growth not keeping pace with economic growth — also contributing to the deficit."

12/2/2008 PAFCO Community Meeting 13

Safety Net Programs Needed More in Down Times

- Food Stamps caseload up 15.5%
- Unemployment Insurance claimants up 48.9%
- Child care assistance up 5.4%
- CPS reports up 3.6%
- AHCCCS enrollment at all time high
- Adult Protective Services investigations up 16.1%

12/2/2008 PAFCO Community Meeting 14

Senate and House Leadership

- Senate – 30 members
  - 18 rep - 12 dem
  - President of the Senate
  - Majority Leader
  - Majority Whip
  - Minority Leader
  - Asst Minority Leader
  - Minority Whip
  - 13 committees +/-
  - Membership and Chairs appointed by President

- House – 60 members
  - 35 rep -25 dem
  - Speaker of the House
  - Majority Leader
  - Majority Whip
  - Minority Leader
  - Asst Minority Leader
  - Minority Whip
  - 18 committees +/-
  - Membership and Chairs appointed by Speaker

12/2/2008 PAFCO Community Meeting 15

Legislative Leadership - 2009

NEW HOUSE LEADERSHIP	NEW SENATE LEADERSHIP
House Majority: Speaker - Kirk Adams Majority Leader - John McComish Majority Whip - Andy Tobin **Minority Leadership** Majority Leader - David Lujan Assistant Minority Leader - Kristen Sinema Minority Whip - Chad Campbell	**Senate Majority:** President - Bob Burns Majority Leader - Chuck Gray Assistant Majority Leader - Pamela Gorman **Minority leadership** Minority Leader - Jorge Garcia Assistant Minority Leader - Rebecca Rios Minority Whip - Linda Lopez

12/2/2008 PAFCO Community Meeting 16

Unfinished Agenda

- Introduction
  - The strengths and promises of Arizona
  - Quality of Life for all
  - Infrastructure for health and human services as critical to quality of life for all
- FOCUS ON SOLUTIONS, not just advocate whining.
- Overarching issues
  - Poverty
  - Workforce
  - Linkages among issues
  - Tax Reform – like elimination of tax exemptions.

- Workforce
- Women's Issues/Domestic Violence, el
- Child Welfare
- Child care -early care and education
- Health Care
- Public Health
- Disability
- Developmental Disability
- After School Programs
- Healthy Families
- Prevention of Family Violence
- Autism
- Aging
- Criminal Justice
- Juvenile Justice
- Substance Abuse
- Behavioral Health
- Poverty,
- Hunger,
- Homelessness
- What else needs to be on the agenda?

12/2/2008 PAFCO Community Meeting 17

Types of Advocacy

- Education
- Organize your agency or group
- Join groups organized around an issue
- Letters to Editor or Op-ED
- Public Speaking
- Organized Rallies
- Neighborhood Caucuses
- Meetings
- Boycotts
- Action Alerts
- Candidate forums
- Elections, voter registration, voter education, voter turnout.
- PAFCO Days Presence

12/2/2008 PAFCO Community Meeting 18

Advocacy Do's and Don'ts

Do
- Be **polite** and friendly
- Be **concise**
- Play on **emotion**
- Include **personal relevance**
- Mention that you are a voting **constituent**
- **Thank them**
- **Follow up** afterwards

Do Not
- Do Not Be **Angry**
- Do Not Be **Hostile**
- Do Not Be **Threatening**
- Do Not Have **too much information**
- Do Not Take up **too much of their time.**
- Do Not **Lose Credibility**
- Do Not Be **Dishonest or Exaggerate**

12/2/2008 PAFCO Community Meeting 19

PAFCO CITIZEN ADVOCACY REMINDERS - Embracing your Citizenship - Register to vote and VOTE!!! IT'S ABOUT POWER!

- **Build relationships** and educate legislators about your issues. Citizen advocacy is about persuasion, not debate.
- **Why will public policy makers listen to you?**
  - You are a constituent from their district, who VOTES!
  - You have good reliable information.
  - You are representative of large group.
- **Know your audience of policy makers**:
- **Tell your story. Be clear about the message.** Make each message simple and direct.
  - Identify yourself as voting constituent.
  - Identify your issue specifically, urge specific action,
  - Provide supporting facts or a story.
  - Specify action again
  - *And always ask how they plan to vote and why?*
  - Thank them.

12/2/2008 PAFCO Community Meeting 20

Messaging Ideas

- **Our message must be relentless:**
  - **Cuts don't make economic sense, demands for services are rising and are countercyclical to economic cycle.**
  - **And now it is not about the poor anymore but all of us in the middle class losing jobs, housing and suffering economic dislocation because of depth and breath of the recession.**
  - **Nobel Prize economist Joseph Stiglitz says that "cutting spending on programs that serve low-income people tends to reduce consumption — and thus state economic activity — by the full amount of the spending reduction."**
  - **Cuts to health and human services serving low income people, many whom are new to poverty and need, clearly makes no sense humanely or economically.**
  - **All options including strengthening revenues and closing tax exemption loopholes on those who can afford it during an economic downturn need to be considered before we cut basic programs for vulnerable children, families and adults.**
  - **We need to protect the common good including health and human services for those in need while balancing economic development and the future needs for the state.**

12/2/2008 PAFCO Community Meeting 21

What can we do together!

- Stay informed and ready to act.
- Know your legislators and let them know you want them to protect health and human services.
- Mobilize your community and groups.
- Talk about budget and policy process at your staff meetings, board meetings, and other groups meetings.
- Mobilize the people you serve in their interest.
- Be visible when you can at the legislature like PAFCO days with your sector group.
- Join PAFCO and another email alert list advocating for the needs of children and vulnerable adults.

12/2/2008 PAFCO Community Meeting 22

It's about Coalition Building and Partnerships
And Action

- Acting with others rather than alone!!!!
- Mobilizing existing resources and creating new advocates
- Flexibility and Action – How to create energy for action!
- How to help and get help?
- Building an email network and list – *spreading* the word!

Our goals remain steadfast:
- **Stop and minimize cuts to vulnerable populations to fullest extent possible,**
- **Try to avoid destruction of health and human services infrastructure since it is so costly to restore and rebuild,**
- **Present options.**

- Patience, perseverance, and persistence.

12/2/2008 PAFCO Community Meeting 23

Finding our Power as Citizens

- Human Dignity and Justice
- We can make it better for ourselves, our children and grandchildren and leave a legacy of community and justice.
- Community - We are not alone, we are in this together and together we are powerful, we can change the world.

- Find your *passion* --- *that cause or group* that motivates you to act.
- Find your *voice* --- your role, your way to be an effective citizen advocate.
- Find your *power* --- connect with others to give practical ways to have real impact for your causes.

12/2/2008 PAFCO Community Meeting 24

PHOENIX, ARIZONA

HIGHLIGHTS FROM THIS YEAR'S SURVEY			
DURING THE LAST YEAR...	HUNGER	HOMELESSNESS	
	INDIVIDUALS & HOUSEHOLDS WITH CHILDREN	INDIVIDUALS	HOUSEHOLDS WITH CHILDREN
REPORTED CAUSES	• UNEMPLOYMENT • POVERTY OR LACK OF INCOME • HIGH TRANSPORTATION COSTS	• FAMILY DISPUTES • SUBSTANCE ABUSE • UNEMPLOYMENT	• DOMESTIC VIOLENCE • UNEMPLOYMENT • EVICTIONS

Profile of Hunger in Phoenix:
During the last year, the number **of requests for food assistance in Arizona has increased 35 percent**. Providers are reporting a significant increase in the number of new persons seeking assistance, especially among working individuals and families. Moreover, there has been an increase in the frequency with which persons access food assistance programs.

In an effort to combat the rising amount of hunger in the Phoenix region, two innovative programs work to provide food assistance to low-income residents. The statewide Arizona Gleaning Project **rescues and distributes food that would otherwise be wasted**. Inspectors from the State Department of Agriculture identify potential donors of surplus products. These products are then harvested by state and county prison inmates and distributed to hungry persons across the state by a network of food banks. The Putting the Pieces Together Initiative, run by the Desert Mission Food Bank, **seeks to educate clients about the nutritional value of a wide variety of foods through hands-on education**. A full-time professional chef conducts live demonstrations at the food bank to educate clients about the nutritional value of the products distributed and different options for food preparation. Recently, the program has been expanded through outreach efforts to other federal and state programs targeting low-income persons.

Profile of Homelessness in Phoenix:
Phoenix reported a **two percent decrease in homelessness** during the last year. However, the number of homeless families using emergency shelter and transitional housing increased during the same period. A Regional Plan to End Homelessness was developed in 2002 and updated in 2005 by the Continuum of Care Regional Committee to End Homelessness. The Continuum of Care is currently developing a revised Ten Year Regional Plan, with a focus on subpopulations including the chronically homeless and homeless families.

Two initiatives in Phoenix aim to prevent homelessness. The City's Human Services Department provides assistance for persons at risk of homelessness. Caseworkers at four Family Services Centers **provide a range of assistance to promote self-sufficiency for adults and families**. Tangible services such as direct financial assistance for utilities and housing, emergency food and transportation assistance are offered, as well as budgeting, education and job training referrals, skill development and counseling. To aid families affected by the mortgage foreclosure crisis, the City of Phoenix is **adopting programs and policies under the Housing and Economic Recovery Act**, particularly the Neighborhood Stabilization Program.

MAYOR: MAYOR PHIL GORDON	CITY WEBSITE: WWW.PHOENIX.GOV
TOTAL POPULATION: 1,513,777	MEDIAN HOUSEHOLD INCOME: $48,061
MEDIAN MONTHLY HOUSING COSTS: $1,059	PERCENT BELOW POVERTY LINE: 17.80%

Arizona

Demographics, Poverty and Food Insecurity

Population (2007)	
Total People	6,338,755
Children (Under Age 18)	1,670,555
Income and Poverty (2007)	
Median Household Income (2007)	$49,889
Rank Among States	23
Total People Living In Poverty	881,257
Poverty Rate	14.2%
Rank Among States (Highest to Lowest)	15
Children (Under Age 18) Living In Poverty	330,910
Child Poverty Rate	20.2%
Rank Among States (Highest to Lowest)	13
Total People Living Below 185% of Federal Poverty Level	1,889,452
Food Insecurity Among Households (2005-2007, 3-Year Averages)	
Number of Households that are Food Insecure	283,000
Percent of Households that are Food Insecure	12.0%
Number of Households that are Very Low Food Secure	108,000
Percent of Households that are Very Low Food Secure	4.6%

Federal Nutrition Programs

School Breakfast Program (School Year 2006-2007)	
Average Daily Student Participation	209,018
Free and Reduced-Price Students	167,112
Paid Students	41,906
Change in Free and Reduced-Price Participation in Last 10 Years	69.3%
Free and Reduced-Price Student Participation Rate (Compared to School Lunch Participation)	40.9
Rank Among States	32
Additional Free and Reduced-Price Students Served if Participation Rate Reached 60%	78,022
Additional Federal Dollars State Would Receive if Participation Rate Reached 60%	$16,722,505
Number of Schools Participating	1,477
School Participation Rate (Compared to Number of Schools Serving Lunch)	90.6%
Federal Funding for School Breakfast	$45,090,216
School Breakfast Mandate in State Law (Yes/No)	No
National School Lunch Program (School Year 2006-2007)	
Average Daily Student Participation	630,718
Free and Reduced-Price Students	408,557
Paid Students	222,162
Number of Schools Participating	1,630
Federal Funding for School Lunch	$174,091,774
Summer Nutrition Participation (July 2007)	
Average Daily Summer Nutrition Participation in July	37,689
July Summer Food Service Participation	7,156
July National School Lunch Participation in Free and Reduced-Price Lunch	30,533
Change in Average Daily Summer Nutrition Participation in Last 10 Years	15.1%
Low-Income Participation Rate (Compared to Regular Year Free and Reduced-Price School Lunch)	10.0
Rank Among States	38
Additional Low-Income Children Served if Participation Rate Reached 40%	113,804
Additional Federal Dollars State Would Receive if Participation Rate Reached 40%	$6,858,949
Number of Summer Food Service Sponsors	34
Number of Summer Food Service Sites	163
Federal Funding for Summer Food Service Program	$2,192,731

Arizona Continued

SNAP/Food Stamp Program (FY 2007)	
Average Monthly Participation (Individuals)	544,688
Change in Participation in Last 5 Years	43.8%
Average Monthly Benefit per Person	$98.95
Participation Rate of Eligible Persons (FY 2005)	66%
Rank Among States	23
Participation Rate of Eligible Working Poor (FY 2005)	54%
Federal Funding for SNAP/Food Stamps	$646,750,299

Special Supplemental Nutrition Program for Women, Infants and Children (WIC) (FY 2007)	
Average Monthly Participation	186,470
Women	47,891
Infants	52,670
Children	85,908
Change in Participation in Last 10 Years	27.9%
Federal Funding for WIC	$114,299,365

Child and Adult Care Food Program (CACFP) (FY 2007)	
Number of Participating Family Child Care Homes	3,452
Family Child Care Home Average Daily Participation of Children	11,400
Change in Family Child Care Daily Participation in Last 10 Years	2.5%
Number of Participating Child Care Centers (Includes Head Start)	674
Child Care Center Average Daily Participation of Children (Includes Head Start)	34,389
Change in Center Daily Participation in Last 10 Years	7.6%
Federal Funding for CACFP	$40,132,024

The Emergency Food Assistance Program (TEFAP) (FY 2007)	
Federal Entitlement Funding	$2,602,776
Federal Bonus Commodity Funding	$950,508
Administrative Funding	$1,201,368

Commodity Supplemental Food Program (CSFP) (FY 2007)	
Average Monthly Participation	14,355
Federal Funding for CSFP	$3,572,979

State Economic Security Policies

Minimum Wage (2007)	
State Minimum Wage	$6.75

Earned Income Tax Credit (EITC) (2007)	
State EITC (Yes/No)	No
Refundable (Yes/No)	No

Temporary Assistance to Needy Families (TANF) (FY 2006)	
Average Monthly Participation (FY 2006)	87,374
Adults	21,710
Children	65,664
Maximum Monthly Benefit per 3-Person Family (FY 2005)	$347
Federal and State Funding for Cash Assistance	$137,114,201

Prevalence of Household-Level Food Insecurity and Very Low Food Security by State 2005-2007 (Average)

State	Food Insecurity (Low or Very Low Food Security)		Very Low Food Security	
	Percent	Rank	Percent	Rank
Alabama	11.9	19	4.3	22
Alaska	12.4	15	4.8	11
Arizona	12.0	18	4.6	14
Arkansas	14.4	4	4.9	8
California	10.2	29	3.5	33
Colorado	11.0	25	4.6	14
Connecticut	8.8	43	3.2	45
Delaware	8.6	45	3.3	42
District of Columbia	11.9	19	3.8	28
Florida	9.0	41	3.4	37
Georgia	13.0	7	5.0	5
Hawaii	8.4	47	2.9	48
Idaho	11.4	24	3.4	37
Illinois	9.5	37	3.5	33
Indiana	10.2	29	3.6	31
Iowa	11.7	22	4.5	18
Kansas	13.0	7	4.7	12
Kentucky	12.7	12	4.5	18
Louisiana	11.7	22	4.6	14
Maine	13.3	5	5.9	2
Maryland	8.6	45	3.4	37
Massachusetts	8.0	48	3.2	45
Michigan	11.8	21	4.5	18
Minnesota	9.5	37	3.7	30
Mississippi	17.4	1	7.0	1
Missouri	12.9	10	4.9	8
Montana	9.5	37	3.8	28
Nebraska	9.5	37	3.4	37
Nevada	10.4	28	4.0	24
New Hampshire	7.7	50	2.8	50
New Jersey	8.8	43	2.7	49
New Mexico	15.0	2	4.9	8
New York	9.9	34	3.3	42
North Carolina	12.6	13	4.0	24
North Dakota	6.5	51	2.2	51
Ohio	12.2	17	4.5	18
Oklahoma	13.0	7	4.7	12
Oregon	12.4	15	5.5	3
Pennsylvania	10.0	33	3.4	37
Rhode Island	10.9	26	3.9	27
South Carolina	13.1	6	5.0	5
South Dakota	9.7	36	3.6	31
Tennessee	12.8	11	4.2	23
Texas	14.8	3	5.0	5
Utah	12.5	14	5.1	4
Vermont	10.2	29	4.6	14
Virginia	8.0	48	3.0	47
Washington	10.1	32	3.5	33
West Virginia	10.7	27	4.0	24
Wisconsin	9.0	41	3.5	33
Wyoming	9.9	34	3.3	42

E-01345A-08-0172

ORIGINAL

ARIZONA CORPORATION COMMIS

UTILITY COMPLAINT FORM

RECEIVED

2008 OCT -1

AZ CORP COMMISSION
DOCKET CONTROL

Investigator: Richard Martinez **Phone:** [redacted] **Fax:** [redacted]

Priority: Respond Within Five Days

Opinion No. 2008 71770 **Date:** 9/29/2008

Complaint Description: 08A Rate Case Items - Opposed
N/A Not Applicable

	First:	Last:
Complaint By:	Claudia	Matanyi

Account Name: Claudia Matanyi **Home:** [redacted]
Street: [redacted] **Work:**
City: Phoenix **CBR:** [redacted]
State: AZ **Zip:** 85000 **is:** E-Mail

Utility Company. Arizona Public Service Company
Division: Electric
Contact Name: [redacted] **Contact Phone:** [redacted]

Nature of Complaint:

Received the following email:

We are on retirement and this summer have had $400 electric bills If APS raises their rates any higher, we will be unable to pay them based on our fixed income. We do everything in our power to lower our rates. We keep our thermostat at 80 degrees, we have protective solar screens on our windows, blinds, 13 florescent bulbs, and we do all of our laundry, run the dishwasher, and out pool all on the off peak hours. We are not an all electric house either. We have a gas water heat, stove/oven, and dryer. We have had our AC system checked, and we use a digital thermostat. Our house is only 9 years old and has higher R-ratings on windows and doors as well. These rates are extremely high for all of the conservatory methods we are currently using. There is no reason the rates need to continuously be raised. We have also notice an extreme amount of additional charges above and beyond our actual electric usage. We would lover to know what all of these charges are and what the money is being used for.
End of Complaint

Utilities' Response:

na
End of Response

Arizona Corporation Commission
DOCKETED
OCT -1 2008
DOCKETED BY

Investigator's Comments and Disposition:

I emailed the following to customer:

Re: Docket No. E-01345A-08-0172

Dear Ms. Claudia Matanyi,

Your correspondence regarding the Arizona Public Service Company rate case will be placed on file with the Docket Control Center of the Arizona Corporation Commission to be made part of the record. The

E-01345A-08-0172

ORIGINAL

ARIZONA CORPORATION COMMIS

UTILITY COMPLAINT FORM

RECEIVED

Investigator: Deb Reagan **Phone:** [redacted] SEP 26 **Fax:** [redacted]

Priority: Respond Within Five Days

AZ CORP COMMISSION DOCKET CONTROL

Opinion No. 2008 71729 **Date:** 9/26/2008

Complaint Description: 08A Rate Case Items - Opposed
N/A Not Applicable

	First:	Last:
Complaint By:	Constance A.	Nuzzi

Account Name: Constance A. Nuzzi

Street: [redacted]

City: Phoenix

State: AZ **Zip:** 85023

Home: (000) 000-0000

Work:

CBR:

is:

Arizona Corporation Commission DOCKETED SEP 26 2008

Utility Company. Arizona Public Service Company

Division: Electric

Contact Name: For assignment **Contact Phone:** n/a

Nature of Complaint:

***** E-01345A-08-0172 *****

Customer sent the following correspondence -

Dear Members of the Commission:

This letter is in regards to the proposed application by APS for a 10.55% on average increases in their base rates, as a permanent increase.

I am a senior citizen on a fixed income of less then $1500/month. Right now my electric bills are averaging 10-15% of my monthly income which leaves me little left for water, insurance, medical coverage, gas, food, etc. I have had to drop my prescription drug plan and my eye exams, glasses, physical therapy, dental are not covered.

I have a small patio home which is well insulated; my windows are tinted, my outside lights are solar; my lights bulbs in house have been changed to energy efficient ones; I only watch TV and cook large meals for the week on off-peak times; all my electric appliances (dishwasher, vacuum, etc) are used off-peak times; I do my own housework and gardening because I cannot afford to hire anyone to do these for me; I keep my air-conditioner on 80; my car is 15 years old and only use it when necessary. I don't know what else to do to conserve.

If this permanent base increase goes through, it will be a devastating hardship for me. Not only will the base increase, but also the 19 additional charges (fees, adjustment, surcharges, taxes, meter reading, etc.) will also increase. Which means my total bill will increase 15% overall.

I strongly request that during this time of recession, your Commission will give this matter very serious consideration. We the customers of APS do not have an alternate electric company to go to there is no competition.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

I anxiously look forward to the final decision in the matter and hope it will be the right one for me and other people in the same predicament as mine, which are many.

Sincerely,
Constance Nuzzi
End of Complaint

Utilities' Response:

.

Investigator's Comments and Disposition:

Responded with the following -

Dear Ms. Nuzzi:

Your correspondence regarding the Arizona Public Service Company rate case will be placed on file with the Docket Control Center of the Arizona Corporation Commission to be made part of the record. The Commissioners will have the opportunity to consider your comments before a decision is rendered in the Company application.

The concerns raised in letters, phone calls and e-mails received from customers will assist staff in the investigation and review of the rate application. Staff's independent analysis of the utility and its rate request attempts to balance the interest of the utility and its customers.

Commission Staff is very sensitive to the burden that high utility rates can place on the consumer, and though constitutionally required to allow a fair return to the utility, does everything within its authority to protect the consumer.

Staff appreciates your comments and the interest taken on the proposed rate increase. If you should have any questions relating to this issue, please call me at [redacted]

Sincerely,

Deborah Reagan
Public Utilities Consumer Analyst
Utilities Division
End of Comments

Date Completed: 9/26/2008

Opinion No. 2008 - 71729

E-01345A-08-0172

Betty Camargo

From: Dottie Martin [dottiemartin1@cox.net]
Sent: Friday, August 08, 2008 1:06 PM
To: Hearings Division; Mayes-WebEmail; Mundell-Web; Gleason-WebEmail; Hatch-WebEmail; Pierce-Web
Subject: APS's Request for a Base Rate SURCHARGE

To Whom It May Concern:

It is my opinion that ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR AN INTERIM RATE INCREASE (DOCKET NO. E-01345a-08-0172) be emphatically declined!!!

My first reaction is, "Of all the nerve!" As if we already don't pay enough for our service! However, this being said, because it is my REACTION, there are enough good reasons why this should not be granted.

With the state of the economy slowing steadily, the price of gas being outrageous, taxes on our homes skyrocketing this year, the housing market slowing to an almost standstill, inflation rising, fewer people emigrating to Arizona - which lowers business profits, and increasing unemployment being the major reasons NOT to slap more charges on its customers, APS is looking to increase their profits at a time when everybody else's are declining. And the media constantly shoving doom and gloom down our throats does not help either.

The definition of the word "surcharge," as found at www.dictionary.com,
or any other dictionary in print, follows:

Dictionary.com Unabridged (v 1.1) - *Cite This Source* - *Share This*
sur·charge Audio Help [*n.* **sur**-chahrj; *v.* sur-**chahrj, sur**-chahrj] Pronunciation Key - Show IPA Pronunciation
noun, verb, **-charged, -charg·ing.**
–noun

1. an additional charge, tax, or cost.
2. an excessive sum or price charged.
3. an additional or excessive load or burden.
4. *Philately.*
   a. an overprint that alters or restates the face value or denomination of a stamp to which it has been applied.
   b. a stamp bearing such an overprint.
5. act of surcharging.

–verb (used with object)

6. to subject to an additional or extra charge, tax, cost, etc. (for payment).
7. to overcharge for goods.
8. to show an omission in (an account) of something that operates as a charge against the accounting party; to omit a credit toward (an account).
9. *Philately.* to print a surcharge on (a stamp).
10. to put an additional or excessive burden upon.

[Origin: 1400–50; late ME *surchargen* (v.) < OF *surcharger.* See SUR-[1], CHARGE]

—Related forms
sur·charg·er, *noun*
Dictionary.com Unabridged (v 1.1)
Based on the Random House Unabridged Dictionary, © Random House, Inc. 2006.

As one can see by the definitions, a "surcharge" is considered "additional," "excessive," and even "an extra load or burden," which, to most people, means that the surcharge is ***not necessary*** in order to conduct business, but just another

"additional" charge to increase profits for the company and its stockholders. Additionally, it's hardly the time to increase charges that do nothing but add another burden to the over-taxed, over-charged, fighting-to-keep-his-head-above-water consumer.

If the Arizona Corporation Commission is reviewing a request such as this, I would hope that they also review the profit margins and particularly the salaries of the higher paid employees. With unemployment rising daily, fewer working people are getting the much needed raises in salaries that they have been expecting. How is APS doing in the President, CEO, etc. salary department?

This increase is not only unnecessary, but extremely untimely. And please do not accept the "gas prices are higher" excuse. APS could save thousands of dollars by decreasing their advertising budget, since they have no need to advertise. Everyone needs electricity, and we are subjected to extremely few options when it comes to choosing our electric service company. They virtually have no competition!

Interestingly, as a local REALTOR®, I find it worth noting that clients often perceive APS as the "more expensive" electric company, and often ask to look at homes in a district where SRP services exist! If SRP can do it, why can't APS?

We are already being "surcharged" to death! Just take a plane these days! Therefore, I request that you please DO NOT approve this surcharge request.

One other incidental thing that you can pass along to APS. In their hearing notice, they keep referring to "**APS'** request." The proper punctuation should be "**APS's** request" (apostrophe "s") since an apostrophe after an "s" signifies that the preceding word that ends in "s" is plural. "APS" is not a plural word, so should use apostrophe "s" even though the word ends in "s." (In my past life I was an English teacher! However, it doesn't mean that this email is flawless.)

Sincerely,

Dottie Martin
6701 E. Camino de los Ranchos
Scottsdale, AZ 85254
realestate@dottiemartin.com

CYNTHIA ZWICK

1940 E. Luke Avenue
Phoenix, AZ 85016

602.432.3464 (cell)
cazwick@qwest.net

SUMMARY

An accomplished executive with 23 years non-profit, association management experience. Management experience includes, personnel, non-dues revenue generation, grant analysis and development, program conceptualization and implementation, and systems analysis and design. Excellent analytical, interpersonal communication and individual and team development skills. Creative and collaborative leadership style with ability to inspire individuals and organizations to grow programmatically while increasing revenues.

SELECTED ACCOMPLISHMENTS

- Designed and implemented processes in Lawyer Regulation to insure fair, prompt handling of bar complaints, resulting in consistent and compassionate treatment of all involved, thereby increasing efficiency and confidence in the lawyer discipline system.
- Conceptualized and introduced a bi-monthly electronic newsletter to all 16,000 State Bar members, resulting in enhanced communication and organizational value. Of total membership, 30 opted to unsubscribe.
- Working with outside technical experts, successfully designed and executed first electronic fund raising effort for the Arizona Foundation for Legal Services & Education, resulting in approximately $50,000 in new gifts.
- Improved member services through more efficient use of technology, organizational systems and personal outreach.

PROFESSIONAL EXPERIENCE

Arizona Community Action Association **September 2003**

Executive Director
Arizona Community Action Association (ACAA), is a non-profit organization working to create systems to support individuals and tools to assist individuals moving to and sustaining self-sufficiency. Working with a Board of Directors, Executive Director oversees the operational issues, writes and manages State and Federal contracts, leads educational and outreach efforts, membership development, and efforts to inform all members of the Arizona community about the issues facing low-income and working poor individuals and families in order to ensure adequate support, with the ultimate goal of ending poverty in Arizona.

State Bar of Arizona
Arizona Foundation for Legal Services & Education **Phoenix, AZ 1980 – May 2003**

Executive Director March 2000-May 2003
Lead both professional organizations, insuring high quality service and programming for all members of the State Bar of Arizona, a mandatory membership organization, as well as participating in the improvement of legal and justice system services available to the greater Arizona community.

Directed the operations of both organizations; advised both Boards with respect to all programs and activities; formulated and recommended policies and programs, including a $9 million budget and budgeting strategies; executed all decisions of the Boards and their various committees; directed programming, projects and major activities of the 100 person staff; responsible for the hiring of personnel, maintenance of salary administration plan and procedures; promoted interest and active participation in the Bar and Foundation activities, resulting in increased funding; created and maintained effective relationships with other public and private organizations; supervised lawyer regulation and government relations efforts; directed the fund raising and grants analysis process for the Foundation.

Assistant Executive Director – Member Services 1995—2000

Member of the Senior Management Team, reported to the Executive Director, worked closely with the Board of Governors. Directed the work of nine diverse divisions of service including:

- Continuing Legal Education
- Mandatory Continuing Legal Education
- Board of Legal Specialization
- Committees, Sections and the Young Lawyers Division
- Community, Media Relations and Publications
- Member Assistance Program
- Law Office Management Assistance Program
- Annual Convention, and
- Tucson Office

Associate Director	1991 – 1995
Director, Programs and Public Services Division	1987 – 1991
Convention Coordinator	1984 – 1987
Committee and Section Administrator/CLE Seminar Coordinator	1980 – 1984

Coordinator, Western States Bar Conference 1986 – 1992

Managed all the logistical and programmatic arrangements for a 14 state, member organization.

Central and Eastern European Law Initiative (CEELI), Consultant to Macedonian Bar Association 2000

EDUCATION AND TRAINING

- Bachelor of Arts, Political Science
  Ohio Wesleyan University, Delaware, Ohio
- Wroxton College, Wroxton, England (a Fairleigh Dickinson University exchange program)

PROFESSIONAL AFFILIATIONS

- Member, National Low Income Energy Consortium, Board of Directors
- Collaboration for a New Century, Board of Directors
- Member, Governor's Task Force on Earned Income Tax Credit
- Valley Leadership, Class XXV
- Member, Arizona Society of Association Executives
- Past Member, National Association of Bar Executives
  Board of Directors, Delegate-at-Large
  Member, Special Committee on Leadership Development
  Chair, Administration and Finance Section
  Chair, Program Committee
- Arizona Town Hall, Member
- Past Member, Greater Phoenix Chamber of Commerce
  Member, Greater Phoenix Crime Coalition

RESPECTFULLY SUBMITTED this December 18, 2008

By_____

Cynthia Zwick
1940 E. Luke Avenue
Phoenix, AZ 85016

Original and 13 copies hand delivered December 18, 2008 to:
Arizona Corporation Commission
Docket Control
1200 West Washington
Phoenix, AZ 85007

Copies To:

Thomas L. Mumaw
Meghan H. Grabel
Arizona Public Service Company
P.O. Box 53999, Mail Station 8695
Phoenix, AZ 85004-3992

Ernest G. Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Timothy Hogan
AZ Center for Law
202 E. McDowell, 153
Phoenix, AZ 85004

Janice Alward
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Daniel Pozefsky
RUCO
1110 W. Washington, Ste. 220
Phoenix, AZ 85007

Lyn Farmer
Chief Hearing Officer, Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Lawrence V. Robertson, Jr.
P.O. Box 1448
Tubac, AZ 85646

Scott Canty
General Counsel Hopi Tribe
P.O. Box 123
Kykotsmovi, AZ 86039

C. Webb Crockett
Fennemore Craig
3003 North Central, Suite 2600
Phoenix, AZ 85012-2913

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Lieutenant Colonel Karen White
139 Barnes Drive
Tyndall AFB, Florida 32403

Nicholas Enoch
349 N. Fourth Avenue
Phoenix, AZ 85003

Jeffrey Woner
KR Saline & Associates PLC
160 N. Pasadena – 101
Mesa, AZ 85201

Michael A. Curtis
501 East Thomas Road
Phoenix, AZ 85012

David Berry
P.O. Box 1064
Scottsdale, AZ 85252-1064

Jeff Schlegl
SWEEP
1167 W. Samalayuca Dr.
Tucson, AZ 85704-3224

Gary Yaquinto
Arizona Utility Investors Assoc.
2100 N. Central, Suite 210
Phoenix, AZ 85004

John Moore, Jr.
7321 N. 16th Street
Phoenix, AZ 85020

Jay Moyes
Moyes Storey
1850 N. Central, 1100
Phoenix, AZ 85004

BEFORE THE ARIZONA CORPORATION COMMISSION

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

DIRECT TESTIMONY OF CYNTHIA ZWICK

July 1, 2009

Q.1 Please state your name.

A.1 My name is Cynthia Zwick.

Q.2 What is the purpose of your testimony at this time?

A.2 I have participated in the settlement discussions and have signed the Settlement Agreement. Pursuant to the Procedural Order issued by Chief Administrative Law Judge Lyn Farmer on May 3, 2009, I am filing this Direct Testimony in support of the Settlement Agreement as it relates to the interests and welfare of low-income families throughout the APS service territory.

Q.3 Why do you believe this is a beneficial agreement?

A.3 My participation in the rate case was limited to Section XVI Low Income Programs and I believe the elements contained in the agreement are beneficial to low-income rate payers, to the Company and to the greater community of rate payers.

In this Agreement, E-3 and E-4 ratepayers will be held harmless from any increase in this case, which will enhance these customers' ability to continue to pay their bills, remain current customers, reducing or eliminating the Company's need for collections activity to take place. Additionally, customers new to APS, newly enrolled in the E-3 or E-4 rates, or only recently eligible for these rates, will be able to access this discount during these very difficult times which continue to create hardships for many formerly middle income and low-income families and individuals.

As more and more families are struggling to pay their utility bills due to the current state of the economy, in a state with an extremely high energy burden, the augmentation of the bill assistance program will provide options for relief to customers who are now at 200% of poverty, consistent with federal assistance programs.

A family that is living at 150% of poverty, $15,600 for an individual annually and $31,800 for a family of four, struggles to make ends meet, and many more individuals are finding themselves unemployed than ever before– 253,700 since December 2007 . The discount, coupled with the agreement in this case that the Company will waive the collection of an additional security deposit from customers on low-income schedules E-3 and E-4 under the circumstances stated in the Agreement, will also assist in the customer's ability to stay connected or get reconnected. This new policy will improve the Company's position and reduce the likelihood the customer will be placed in any danger.

Finally, the continued exemption of low-income customers from the DSMAC charge is one more way to provide the support needed by the low-income community to remain current on their utility bills, with minimal impact on rate payers.

It is my belief that low-income customers are extremely vulnerable to high utility bills at this particular time as unemployment rates in Arizona continue to rise, as the number of families without health insurance increase daily, and seniors living on fixed incomes continue to have to make difficult choices about which bills to pay. Providing families one option for staying healthy, safe and in their homes reduces greater community costs, reduces costs the Company may have to incur due to disconnections, collections or accidents occurring. Additionally, these provisions ensure that many more customers will be able to receive assistance in the event of a crisis, or are now able to maintain current accounts, which is also beneficial to the entire community.

Q.4 Does this conclude your testimony?

A.4 Yes, it does.