0000134114

# Transcript Exhibit(s)

Docket #(s): E-01345A-11-0224

Exhibit # : AAR1-AAR2; AIC1-AIC5; AECC1-AECC4;
N1; FEA1-FEA3; GSP1-GSP2; IBEW1-IBEW2;
Kroger1-Kruger3; NRDC1-NRDC2; RUCO1-RUCO4
part 3 of 5

Arizona Corporation Commission
DOCKETED
FEB - 6 2012
DOCKETED BY

RECEIVED
2012 FEB -6 P 3:04
AZ CORP COMMISSION
DOCKET CONTROL

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE - Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
AAR-1
ADMITTED

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN | **DOCKET NO. E-01345A-11-0224** |

# PRE-FILED DIRECT TESTIMONY OF TOM FARLEY

# ON BEHALF OF

# THE ARIZONA ASSOCIATION OF REALTORS

**November 18, 2011**

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Tom Farley. My business address is 255 E. Osborn Road, Suite 200, Phoenix, Arizona 85012.

**Q. WHERE ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am Chief Executive Officer of the Arizona Association of Realtors, a position I have held since ~~1997~~ 2008.

**Q. WHAT IS THE ARIZONA ASSOCIATION OF REALTORS?**

A. The Arizona Association of Realtors (the "Association") is the largest trade association in Arizona, representing approximately 43,000 Arizona realtors belonging to 21 local associations. The Association provides benefits and services to its members who are active real estate licensees from all areas of real estate, including residential, commercial, property management, land, appraisal and relocation. A large number of the members of the Association are residential and/or commercial retail electric customers of Arizona Public Service Company ("APS" or the "Utility"). They own real property and are engaged in the business of representing buyers and sellers of real property in Arizona.

**Q. WHY IS THE ASSOCIATION PARTICIPATING IN THIS RATE CASE?**

A. The Association intervened[1] in this rate case because of the interest of its members in the line extension polices of APS, and specifically, the Utility's Service Schedule 3 (*Conditions Governing Extensions of Electric Distribution Lines and Service*). The Arizona Corporation Commission ("Commission") approved version 12 of Service Schedule 3 in Decision 72684 (November 18, 2011) in Docket E-01345A-11-0207. Pursuant to that decision, Service Schedule 3, version 12, will become effective concurrently with the effective date of new base electric rates approved in this rate case. The Association supports Service Schedule 3, version 12.

---

[1] The Association filed an Application for Leave to Intervene in the rate case on July 15, ~~2001~~ 2011, and intervention was granted by the Commission at the procedural conference held July 18, 2011.

**Q. PLEASE DISCUSS THE CIRCUMSTANCES THAT LED TO THE COMMISSION'S APPROVAL OF SERVICE SCHEDULE 3, VERSION 12.**

A. Service Schedule 3 sets forth the terms and conditions under which APS will extend, relocate or upgrade facilities in order to provide service to a customer. In Decision 69663 (June 28, 2007) in APS' last rate case, the Commission ordered APS to file "revised line extension tariffs that eliminate any free footage or free allowance and remove any requirement for economic feasibility analysis as otherwise required pursuant to A.A.C. R14-2-207.C.1 and C.2." In compliance with the Commission's order, APS filed a revised version of Service Schedule 3 (Version 10) on July 27, 2007, and then filed an amended version of the tariff on October 24, 2007. The Commission approved Service Schedule 3, version 10, in Decision 70185 (February 27, 2008). The Commission subsequently approved Service Schedule 3, version 11, in Decision 71448 (December 30, 2009).

The Association and others opposed the revision of Service Schedule 3 to eliminate the free footage and other allowances. The Association and others met with APS and the Commission to work toward a compromise that would restore a sharing of extension costs between new applicants and the Utility. As a result of meetings and good faith discussions, an agreement was reached regarding additional revisions to Service Schedule 3. The agreement, which is captioned *Proposed Agreement on Issues related to Arizona Public Service Company's Service Schedule 3* (the "Proposed Agreement"), and dated May 20, 2011, was signed by APS, the Association, the Home Builders Association of Central Arizona, Barbara Wyllie-Pecora, the Residential Utility Consumer Office, the Arizona Investment Council and IBEW Locals 382 and 769. In accordance with the Proposed Agreement, APS prepared revisions to Service Schedule 3 in version 12 for the Commission's consideration and approval.

APS filed Service Schedule 3, version 12, with the Commission for approval on May 20, 2011 in Docket E-01345A-11-020.[2] On July 26, 2011, APS filed an amended

[2] The Association filed an Application for Leave to Intervene in the docket on July 18, 2001, and intervention was granted by the Commission in a procedural order dated August 1, 2011.

application with revisions to Service Schedule 3. On September 30, 2011, the Utilities Division Staff ("Staff") docketed its Staff Report recommending approval of Service Schedule 3 with certain proposed revisions. On October 7, 2011, the Homebuilders Association of Central Arizona docketed a letter requesting one additional revision to Service Schedule 3. At the Open Meeting on November 8, 2011, the Commission approved Service Schedule 3, version 12, including the revisions proposed by Staff and the revision requested by the Homebuilders Association of Central Arizona. The approval is contained in Decision 72684.

**Q. DOES THE COMMISSION'S APPROVAL OF SERVICE SCHEDULE 3, VERSION 12, IN DECISION 72684 ADDRESS THE ASSOCIATION'S CONCERNS IN THE RATE CASE?**

A. Yes. The Association fully supports Service Schedule 3, version 12, as adopted by the Commission in Decision 72684. The Association will continue to monitor the rate case, but does not intent to participate actively in the hearing unless an issue is raised regarding Service Schedule 3, version 12.

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

A. Yes.

15244\1\1612090.1

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE - Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
AAR-2
ADMITTED

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN

**DOCKET NO. E-01345A-11-0224**

# PRE-FILED TESTIMONY OF TOM FARLEY IN SUPPORT OF PROPOSED SETTLEMENT AGREEMENT

January 18, 2012

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Tom Farley. My business address is 255 E. Osborn Road, Suite 200, Phoenix, Arizona 85012.

**Q. WHERE ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I have been employed by the Arizona Association of Realtors since 1997 ~~1998~~, and have served as its Chief Executive Officer since 2008.

**Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS CASE?**

A. Yes. I filed testimony on November 18, 2011.

**Q. WHAT IS THE ARIZONA ASSOCIATION OF REALTORS?**

A. The Arizona Association of Realtors ("Association") is the largest trade association in Arizona, representing approximately 43,000 Arizona realtors belonging to 21 local associations. The Association provides benefits and services to its members who are active real estate licensees from all areas of real estate, including residential, commercial, property management, land, appraisal and relocation. A large number of the members of the Association are residential and/or commercial retail electric customers of Arizona Public Service Company ("APS" or the "Utility"). They own real property and are engaged in the business of representing buyers and sellers of real property in Arizona.

**Q. WHY DID THE ASSOCIATION INTERVENE IN THIS RATE CASE?**

A. The Association intervened[1] in this rate case because of the interest of its members in the line extension policies of APS, and specifically, the Utility's Service Schedule 3 (*Conditions Governing Extensions of Electric Distribution Lines and Service*). The Arizona Corporation Commission ("Commission") approved version 12 of Service Schedule 3 in Decision 72684 (November 18, 2011) in Docket E-01345A-11-0207. Pursuant to that decision, Service Schedule 3, version 12, will become effective concurrently with the effective date of new base electric rates approved in this rate case. The Association supports Service Schedule 3, version 12.

[1] The Association filed an Application for Leave to Intervene in the rate case on July 15, 2011, and intervention was granted by the Commission at the procedural conference held July 18, 2011.

**Q. WHAT IS THE PURPOSE OF YOUR PRE-FILED TESTIMONY TODAY?**

A. I am filing this testimony in support of the Proposed Settlement Agreement that was filed with the Commission on January 6, 2012.

**Q. DID THE ASSOCIATION PARTICIPATE IN THE NEGOTIATIONS THAT PRODUCED THE PROPOSED SETTLEMENT AGREEMENT?**

A. Yes. Through its legal counsel, the Association participated in a substantial portion of the settlement meetings and negotiations.

**Q. DOES THE ASSOCIATION SUPPORT THE PROPOSED SETTLEMENT AGREEMENT?**

A. Yes. Section XV of the Proposed Settlement Agreement specifically addresses the Association's concerns, stating that "Version 12 of Service Schedule 3, as approved in Decision No. 72684 (November 18, 2011), shall become effective on the date that rates from this case become effective." Based upon the inclusion of Section XV, the Association signed the Proposed Settlement Agreement.

**Q. DOES THE ASSOCIATION RECOMMEND THAT THE COMMISSION APPROVE THE PROPOSED SETTLEMENT AGREEMENT?**

A. Yes. I believe the Proposed Settlement Agreement represents a just and reasonable outcome for APS customers, the Association, and other stakeholders in the case.

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

A. Yes.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
AIC-1
ADMITTED

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | Docket No. E-01345A-11-0224 |

**Direct Testimony of**

**Gary Yaquinto**

**on Behalf of**

**Arizona Investment Council**

**November 18, 2011**

## TABLE OF CONTENTS



**EXHIBITS: AIC Exhibit GY-1**

## INTRODUCTION

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

A. Gary M. Yaquinto. I am the President of the Arizona Investment Council ("AIC"). Our offices are located at 2100 North Central Avenue, Phoenix, Arizona 85004.

**Q. Please summarize your educational background and professional experience.**

A. I earned B.S. and M.S. Degrees in Economics in 1974 from Arizona State University. In 2005, I received an MBA from the University of Phoenix. From 1975 to 1977, I was employed by the State of Wyoming as an economist responsible for evaluating the economic, fiscal and demographic effects of resource development in Wyoming. From 1977 to 1980, I was Chief Research Economist for the Arizona House of Representatives. From 1980 to 1984, I was employed as an economist in the consulting industry. Since 1984, I have worked in various capacities in government and the private sector in the area of utility regulation, including positions with the Utilities Division Staff of the Arizona Corporation Commission, a competitive local exchange telephone carrier and as a consultant. I have also served as the Chief Economist at the Arizona Attorney General's Office (2003-2005) and as the Director, Office of Strategic Planning and Budgeting, under Governor Janet Napolitano (2005-2006). I became the AIC President in December of 2006.

**Q. What is the Arizona Investment Council and what is its mission?**

A. The AIC is a non-profit association organized under Chapter 501(c)(6) of the Internal Revenue Code. AIC's membership includes approximately 6,000 individuals—many of whom are debt and equity investors in Arizona utility companies and other Arizona businesses.

AIC's mission is to advocate on behalf of its members' interests before regulatory and legislative bodies, and specifically to enlarge and maximize the influence of utility investors on public policies and governmental actions that may have an impact on the well-being of investors and their utility investments.

AIC also works with policymakers to support investment in Arizona's essential backbone infrastructure. We view this aspect of our mission as complementary to our core advocacy of investor interests. Investment in essential, backbone infrastructure is critical in supporting a well-functioning and robust economy. In 2008, AIC published "Infrastructure Needs and Funding Alternatives for Arizona: 2008-2032"—a comprehensive study that examined infrastructure and funding requirements over that 25-year period in four important areas: energy, water, telecommunications and transportation. This report, prepared by economists from Arizona State University, estimated investment requirements of about $500 billion to meet our growing needs in these four critical areas over the next two and one-half decades. The findings demonstrate Arizona's continuing need for substantial capital attraction.

**Q. Please summarize AIC's interest in this case.**

A. Given our mission as the voice of investors, AIC's overriding interest in this case is to help ensure that APS continues to improve its financial health so the company can attract capital on the best possible terms and rates for investment in Arizona's energy future. The testimonies of AIC witnesses Steven Fetter and Dr. Daniel Hansen provide specific recommendations on, and other information in support of, this goal. Mr. Fetter, a former regulator and utility financial analyst with credit rating agency Fitch, describes the importance of ratings in capital attraction for utility companies; the factors rating agencies consider in determining ratings; the challenges APS faces in competing for capital; and how the EIA and ERA proposed by APS can assist it and Arizona in that capital contest. Dr. Hansen also provides testimony in support of APS's proposed EIA decoupler.

## APS'S POSITIVE ECONOMIC IMPACT

**Q. Is there anything else you would like to bring to the Commission's attention?**

A. Yes. APS is Arizona's largest electric utility. It has been providing service to Arizona customers since 1886. With approximately 6,400 Arizona employees on the company's payroll and annual cap-ex programs approaching $1 billion, APS is a major contributor to Arizona's economy. When you also consider the indirect jobs and income generated through the multiplier effect resulting from APS's direct expenditures, the company's total impact on the State economy is huge. APS, its employees and vendors also pay taxes, which fund public services like education and safety and help support State and local governments in Arizona.

While maintaining the company's financial health is important to investors and customers, my point is that a financially strong APS plays an equally important role in Arizona's economy.

**Q. Is there a study analyzing APS's direct and indirect contribution to Arizona's economy?**

A. Earlier this year, economists at ASU's W.P. Carey School of Business, the L. William Seidman Research Institute, prepared a study on this subject. The study—titled "The Economic Impact of Arizona Public Service (APS) on the States of Arizona and New Mexico in 2010"—quantifies the value that APS brings to the economies of both states in terms of jobs, commerce and taxes. The study used a well-known computer model called IMPLAN to estimate APS's direct economic contributions, as well as the indirect effects associated with additional rounds of spending or "recycled" income.

I've attached a copy of this study to my testimony as AIC Exhibit GY-1.

**Q. What does the study tell us about APS's direct and indirect impacts on jobs in Arizona?**

A. In 2010, APS employed about 7,500 workers (including positions with contractors) at various sites in Arizona. These are the direct workers associated with APS, as well as those on contractor payrolls. Additionally, APS also supports jobs associated with its purchases from suppliers, which account for an additional 5,600 jobs.

The indirect effects of spending by APS employees supported more than 5,300 additional employment positions and the indirect effect of spending by APS suppliers accounted for 5,100 more jobs. Finally, the indirect effect of State and local taxes paid by APS supported more than 15,000 jobs in Arizona's government sector.

The total employment effect of APS operations in 2010 was approximately 39,000 jobs, or about 1.2 percent of total employment in Arizona—a very significant level for one of Arizona's largest native corporations. Another way of looking at its effect on jobs in our State is that for every APS job (including its contractors), another 4.2 positions were supported in Arizona's economy.

**Q. What are APS's direct and indirect effects on income in Arizona?**

A. Like its impact on jobs, APS has both direct and indirect income effects.

The direct income associated with APS operations in 2010 was $1.3 billion. APS's purchases from vendors accounted for an additional $463 million.

Indirect income from consumer spending of APS employees produced $363 million and indirect income effects related to supplier purchases totaled $372 million. The indirect income effect related to APS's tax payments to the State and local governments was $869.4 million.

Total income—direct and indirect—traced to APS was $3.372 billion, or 1.3 percent of the total gross State product.

**Q. What amount does APS directly contribute to State and local taxes?**

A. As Arizonans know, State and local governments have struggled mightily to balance their budgets over the past few years. The precipitous drop in government revenue collections during the Great Recession has created a huge budgetary hole from which we're only now beginning to recover. One constant, however, in tax collections has been the contributions of companies like APS that are both economically stable and rooted in Arizona's communities.

In 2010, APS paid directly $122.1 million in property taxes and $285.5 million in sales and use taxes to all levels of government in Arizona. According to the ASU study, when calculated on a per-employee basis, APS's $52,000 per employee contribution is 17 times more than the average Arizona business to State and local taxes.

**Q. Is there an indirect APS effect on State and local taxes?**

A. Yes. APS employees pay taxes based on salary, property ownership and retail purchases. Obviously, its vendors and their employees pay taxes as well. The direct and indirect tax effects associated with APS employees and vendors account for an additional $184 million in taxes to Arizona governments.

## CONCLUSION

**Q. Mr. Yaquinto, based on the ASU study of the economic impact of Arizona Public Service Company, what conclusions do you have with respect to the Commission's decision in this docket.**

A. First, the role that utility companies like APS play in fueling the State's economy is an often overlooked aspect of rate cases. While the Commission's primary decisionmaking responsibility is to balance the interests of customers and investors, the Commission should also take into consideration how its ratemaking processes and decisions affect the State's macro-economy. As the ASU study clearly shows, the direct and indirect economic effects related to APS's operations are substantial.

Second, fit-for-purpose infrastructure is an essential component for fostering an efficient and robust State economy—one that can offer prosperity for all Arizonans. Over the next several decades, the infrastructure requirements for meeting Arizona's energy needs will be immense. Failure to make the necessary and proper investments will impair our economic future.

Therefore, keeping APS and other utility companies financially healthy and stable is a necessary and very important ingredient for attracting capital to invest in essential infrastructure.

**Q. Does that conclude your testimony?**

A. Yes, it does.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
tabbies
AIC-2
ADMITTED

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | Docket No. E-01345A-11-0224 |

**Direct Testimony of**

**Steven M. Fetter**

**on Behalf of**

**Arizona Investment Council**

**November 18, 2011**

## TABLE OF CONTENTS

## I. INTRODUCTION AND BACKGROUND

**Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.**

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is P.O. Box 280, Nordland, Washington 98358.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC"). Earlier, I served as Majority General Counsel to the Michigan State Senate and Assistant Legal Counsel to Michigan Governor William Milliken, and as Acting Deputy Under Secretary of Labor and appellate litigation attorney at the National Labor Relations Board in Washington, D.C.

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

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

**Q. PLEASE DESCRIBE YOUR SERVICE ON THE MICHIGAN PUBLIC SERVICE COMMISSION.**

A. I was appointed as a Commissioner to the three-member Michigan PSC in October 1987 by Democratic Governor James Blanchard. In January 1991, I was promoted to

Chairman by incoming Republican Governor John Engler, who reappointed me in July 1993. During my tenure as Chairman, timeliness of commission processes was a major focus and my colleagues and I achieved the goal of eliminating the agency's case backlog for the first time in 23 years.

**Q. PLEASE BRIEFLY DESCRIBE YOUR ROLE AS PRESIDENT OF REGULATION UNFETTERED.**

A. I formed a utility advisory firm to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. Since April 2002, I have participated in over 85 cases related to utilities, most of the time as an expert witness testifying as to credit rating issues and regulatory climate. My clients have included investor-owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors.

**Q. WHAT WAS YOUR ROLE DURING YOUR EMPLOYMENT WITH FITCH?**

A. I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team. I was originally hired to interpret the impact of regulatory, legislative, and political developments on utility credit ratings, a responsibility I continued to have throughout my tenure at the rating agency. In April 2002, I left Fitch to start Regulation UnFettered.

**Q. HOW LONG WERE YOU EMPLOYED BY FITCH?**

A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant for a period of approximately six months shortly after I resigned.

**Q. HOW DOES YOUR EXPERIENCE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?**

A. My testimony addresses the relationship between regulation and a utility's ability to access capital and manage risk. My background as Chairman and Commissioner on the Michigan PSC and my subsequent professional experience analyzing the electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role in setting rates and also in determining appropriate terms and conditions of service for regulated utilities.

Specifically, my experience with Fitch confirmed that regulatory environment is a key factor in utility credit analysis and formulation of individual company credit ratings. Further, it is undeniable that a utility's credit ratings significantly affect the ability of a utility to raise capital on a timely basis and upon reasonable terms. It is also crucial that a regulated utility be in a position to raise capital in all phases of its business cycle and whatever the circumstances within the financial markets and general economy.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY AND LEGISLATIVE BODIES?**

A. Since 1990, I have testified on numerous occasions before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, federal district and bankruptcy courts, and various state legislative, judicial, and regulatory bodies on the subjects of credit risk within the utility sector, electric and natural gas utility restructuring, fuel and other energy cost adjustment mechanisms, construction work in progress and other interim rate recovery structures, utility securitization bonds, and nuclear energy. I have previously testified before the Arizona Corporation Commission ("ACC" or "Commission") on behalf of Arizona Public Service Company ("APS" or the "Company") in Docket Nos. E-01345A-03-0437, E-01345A-05-0816, and E-01345A-06-0009, and on behalf of Southwest Gas Corporation in Docket No. G-01551A-04-0876.

My full educational and professional background is presented in AIC Exhibit SMF-1.

## II. OVERVIEW OF TESTIMONY

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

A. I am testifying on behalf of the Arizona Investment Council in this proceeding and will focus on the following issues:

a) building on progress made as a result of the Settlement Agreement approved by the ACC in 2009, the importance of APS continuing to improve its financial health, so as to be able to withstand not only the normal financial risks that accompany day-to-day operation of a regulated utility, but also the extreme stresses that can be brought on by a global and national financial crisis similar to the one starting three years ago and still underway; as part of my analysis, I discuss the Company's current credit ratings and the benefits for both customers and investors that a stronger credit rating profile would provide;

b) the Company's proposed decoupling mechanism and how it fits within the context of the broader use of decoupling mechanisms across the U.S.; and

c) the Company's proposed infrastructure investment mechanism and how it will assist APS in managing its risks and attracting capital as it invests in maintenance and enhancement of its generation, transmission, and distribution facilities, and also endeavors to meet renewables and energy efficiency mandates.

## III. CREDIT RATING PROCESS

**Q. PLEASE PROVIDE AN OVERVIEW OF THE CREDIT RATING PROCESS.**

A. Credit ratings reflect a credit rating agency's independent judgment of the general creditworthiness of an obligor or the creditworthiness of a specific debt instrument. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the financial strength of a company or the underlying credit quality of a particular debt security issued by that company. Credit rating determinations are made through a committee process involving individuals with knowledge of a company, its industry, and its regulatory environment. Corporate rating designations of Standard & Poor's ("S&P") and Fitch basically have 'AA', 'A' and 'BBB' category ratings within the investment-grade ratings sphere, with 'BBB-' as the lowest investment-grade rating and 'BB+' as the highest non-investment-grade rating. Comparable rating designations of Moody's at the investment-grade dividing line are 'Baa3' and 'Ba1', respectively.

Corporate credit ratings analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of the ultimate recovery of investment in case of default or insolvency. Ratings can also be used by contractual counterparties to gauge both the short-term and longer-term health and viability of a company. Credit ratings are very important to institutional investors because rating levels often dictate the types of investments that are appropriate and/or permissible for a specific investor.

**Q. CAN YOU PROVIDE A BRIEF DISCUSSION ON WHY CREDIT RATINGS ARE IMPORTANT FOR REGULATED UTILITIES AND THEIR RATEPAYERS?**

A. Yes. A utility's credit ratings have a significant impact on whether that utility will be able to raise capital on a timely basis and upon reasonable terms. As respected economist Charles F. Phillips stated in his treatise on utility regulation:

> Bond ratings are important for at least four reasons: (1) they are used by investors in determining the quality of debt investment; (2) they are used in determining the breadth of the market, since some large institutional investors are prohibited from investing in the lower grades; (3) **they determine, in part, the cost of new debt, since both the interest**

> **charges on new debt and the degree of difficulty in marketing new issues tend to rise as the rating decreases**; and (4) they have an indirect bearing on the status of a utility's stock and on its acceptance in the market.[1]

Thus, a utility with strong credit ratings is not only able to access the capital markets on a timely basis at reasonable rates – especially during periods of economic turmoil – it also shares the benefit of those attractive interest rates with ratepayers, because the cost of capital is factored into utility rates. Conversely, the lower a regulated utility's credit rating, the more the utility will have to pay to raise funds from debt and equity investors which increases the rates that consumers have to pay. This is especially true for a utility like APS, with its ongoing significant capital investment requirements needed to ensure continuing reliability and safety of service to its ratepayers, as well as the cost of meeting environmental, renewables and energy efficiency mandates. Moreover, in the current markets, there is significant competition for capital, which heightens the importance of APS achieving and then maintaining a favorable rating.

**Q. WHAT ARE THE QUALITATIVE FACTORS USED BY THE RATING AGENCIES?**

A. The most important qualitative factors include regulation, management and business strategy, and, for electric and natural gas utilities, access to energy, gas and fuel supply with recovery of associated costs.

[1] Phillips, Charles F., Jr., The Regulation of Public Utilities, Arlington, Virginia: Public Utilities Reports, Inc., 1993 at p. 250 (emphasis added). *See also* Public Utilities Reports Guide: "Finance," Public Utilities Reports, Inc., 2004 at pp. 6-7 ("Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid.").

**Q. WOULD YOU ALSO IDENTIFY THEIR KEY QUANTITATIVE MEASURES?**

A. The three major rating agencies use several financial measures within their utility financial analysis. S&P currently highlights the following three ratios as its key indicators: Funds from Operations / Debt ("FFO/Debt"); Debt / Earnings Before Interest, Taxes, Depreciation and Amortization ("Debt/EBITDA"); and Debt / Capital.[2] Rating agencies may adjust these key ratios to reflect imputed debt and interest-like fixed charges related to operating leases and certain other off-balance sheet obligations. While all three ratios are important, S&P has noted the agency's greater emphasis on level of cash flow, as indicated by the FFO / Debt ratio: "Cash flow analysis is the single most critical aspect of all credit rating decisions."[3]

**Q. YOU MENTIONED REGULATION AS A KEY COMPONENT OF THE CREDIT RATING PROCESS. PLEASE EXPAND ON THE ROLE REGULATION PLAYS IN THE RATING PROCESS.**

A. Regulation is a critical factor in assessing the utility's credit profile because a public utility commission determines rate levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service.

Regulation has become an even more important factor as the nature of a utility's responsibilities in providing energy services to ratepayers has undergone dramatic change. This affects utility investors' decisions because – before major investors are willing to put forward substantial sums of money – they want comfort that regulators

[2] S&P Research: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.
[3] S&P Research: "A Closer Look at Ratings Methodology," November 13, 2006.

understand the economic requirements and the financial and operational risks of a rapidly changing industry and that their decision-making will be fair with a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by utility regulators. If a regulatory body encourages a company to make investments based upon an expectation of the opportunity to earn a reasonable return and then does not apply regulatory principles in a manner consistent with such expectations, investor interest in providing funds to such a utility declines, debt ratings suffer, the utility's cost of capital increases and, correspondingly, so do rates.

**Q. HAVE THE RECENT FINANCIAL AND OPERATIONAL CHALLENGES FACING ALL UTILITIES INCREASED THE FINANCIAL COMMUNITY'S FOCUS ON THE ACTIONS OF UTILITY REGULATORS?**

A. Without a doubt. The recent and ongoing turmoil in the financial markets has tested the financial standing of the utility sector like never before. Liquidity – or access to cash when needed – has always been a major issue for regulated utilities, but it has leaped to the forefront of utility financial and operational concerns. As the Wall Street Journal reported at the beginning of the financial crisis, "Disruptions in credit markets are jolting the capital-hungry utility sector, forcing companies to delay new borrowing or to come up with different – and often more costly – ways of raising cash."[4] Credit spreads for "BBB"-rated debt issuers are higher than for "A"-rated issuers, and significantly higher when credit markets are in distress. Clearly, the negative global economic crisis that

---

[4] "Utilities' Plans Hit by Credit Markets," Wall Street Journal, October 1, 2008.

started during the Fall of 2008 has illustrated that "BBB" category utilities are much more vulnerable than "A" category utilities when capital markets are in a state of upheaval. Diminished investor interest and higher costs to serve ratepayers are the two major threats to their operational efficiency and financial stability.

Thus, while "Regulation" has always garnered close scrutiny by the financial community, years ago, it was a focus only during the days leading up to a regulator's rate case decision. This began to change about the time that Fitch hired me in 1993 to serve in the role of regulatory analyst to assess other regulatory, legislative and political factors that could affect a utility's financial strength. When California announced its ultimately ill-fated restructuring plan in 1994, the entire financial community took much greater notice of regulators and how they carried out their responsibilities, not just with regard to rate-setting, but also the manner in which they considered various restructurings of and new mandates affecting the entire utility industry. And, of course, the recent stresses within credit markets with their huge financial repercussions have increased the stakes substantially as well.

**Q. DO THE RATING AGENCIES AGREE THAT UTILITY REGULATORS AND THEIR DECISION-MAKING CONTINUE TO BE IMPORTANT WITHIN THE CREDIT RATING PROCESS?**

A. Yes. S&P highlighted the critical role that regulators play in a November 26, 2008 report entitled "Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry":

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment.

As discussed below, this view by the rating agencies has been more recently confirmed in connection with APS' credit evaluation and the weight given the Commission's actions in that process.

## IV. APS' CREDIT RATING

**Q. WHAT ROLE CAN WE EXPECT THE POLICIES OF THE ARIZONA CORPORATION COMMISSION TO PLAY IN THE RATING AGENCIES' ANALYSIS OF APS?**

A. The rating agencies' close focus on regulatory decisions means that a supportive decision here – consistent with the Commission's approval of the 2009 Settlement Agreement – would be viewed favorably by the financial community. As can be seen in the following agency statements, regulatory policies of this Commission are a major factor in the credit rating analytical process. S&P, when upgrading the Company's corporate credit rating from 'BBB-' (the lowest investment-grade level) to 'BBB' (with continuation of a 'Positive' outlook) in June 2011, highlighted the key role that a constructive regulatory environment plays in supporting higher credit ratings:

> The positive outlook reflects our view that we could raise the long-term credit rating another notch if regulatory dealings remain constructive … APS' progress in managing its regulatory agenda in Arizona provides a

> platform for higher ratings contingent on financial prudence in containing costs and financing capital investments.[5]

**Q. BEFORE WE MOVE ON TO MOODY'S VIEW, DOES THE ACTION BY S&P SURPRISE YOU AT ALL?**

A. Yes it does, but not necessarily as to the fact that a constructive regulatory decision led to a credit rating upgrade. That makes a lot of sense to me. The surprise was that S&P not only upgraded APS' rating, but also continued its "Positive" outlook. During my eight-and-a-half years rating utilities at Fitch, I would guess that an upgrade accompanied simultaneously by a *continued outlook* of 'Positive' did not occur more than a handful of times.

**Q. DO YOU SEE THAT AS SIGNIFICANT?**

A. Very much so. That continuing 'Positive' outlook leads me to believe that another constructive result in this rate case could very well result in APS being upgraded again to 'BBB+'. I have consistently testified that that highest notch within the 'BBB' category provides downside protection for a regulated utility operating during volatile economic times, and places it just below the 'A' category – my ultimate recommended level, since a rating in the 'A' category should ensure that a utility will be able to access the capital markets even during financial crises and without having to pay exorbitant interest rates. Each of these results is very good news, not only for APS, but for the Commission and ratepayers in these times of continuing economic stress.

---

[5] S&P Research Update: "Pinnacle West Capital Corp. and Arizona Public Service Co. Ratings Raised to 'BBB', June 24, 2011.

**Q. HOW DOES MOODY'S VIEW APS' SITUATION?**

A. Moody's has assigned APS an issuer rating of 'Baa2', which is comparable to the S&P rating, but with a 'Stable' outlook. One of Moody's major concerns is that while the ACC's "[r]egulatory supportiveness [is] showing signs of improving … significant regulatory lag and uncertain timing of rate case resolutions" lead Moody's to view APS' regulatory environment as well below the supportiveness needed for consistency with a 'Baa' category credit rating.[6]

**Q. YOU DESCRIBED EARLIER THREE KEY QUANTITATIVE MEASURES – FFO/DEBT, DEBT/EBITDA AND DEBT/CAPITAL – USED BY THE RATING AGENCIES. PLEASE DISCUSS HOW S&P FRAMES THE QUALITATIVE AND QUANTITATIVE FACTORS INTO A MATRIX TO ASSIST ANALYSTS AND INVESTORS.**

A. As seen in the rating agency statements above, financial performance continues to be a very important element in credit rating analysis. Building upon the three indicative ratios, S&P has explained how it views the interplay between quantitative and qualitative factors. As part of its utility credit rating process, S&P arrives at a "Business Risk Profile" designation that it considers in concert with its "Financial Risk Profile." Financial Risk is assessed based upon indicative ratios for the three key credit measures described above; the weaker the Business Risk Profile designation, the stronger the financial ratios must be in order to support an investment-grade rating.[7]

---

[6] Moody's Credit Opinion: "Arizona Public Service Company," February 25, 2011.
[7] S&P Research: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

**Q. WHAT DOES S&P'S BUSINESS RISK PROFILE DESIGNATION REFLECT?**

A. The Business Risk Profile designation reflects S&P's assessment of qualitative factors such as country risk, industry risk, competitive position, and profitability / peer group comparisons. In the past, S&P explained that assessment of regulation, markets, operations, competitiveness, and management enters into the determination of a Business Risk designation.[8] Under the S&P Methodology, Business Risk Profiles range from 'Excellent' to 'Vulnerable'. Similarly, under S&P's current framework, the Financial Risk designation captures risks related to accounting, financial governance and policies / risk tolerance, cash flow adequacy, capital structure / asset protection and liquidity / short-term factors. Financial Risk Profile descriptions move from 'Minimal' to 'Highly Leveraged' – words that are used more for ranking than as descriptions of the strategies adopted by regulated utilities or the actions taken by their regulators.

APS has been assigned an S&P Business Risk Profile of 'Excellent' and a Financial Risk Profile of 'Aggressive'. As shown in S&P's Table 1 printed below, the Company's risk profile is consistent with its current corporate rating of 'BBB'. Because S&P does not assign ratings solely on this matrix, but uses it as a guide, most rating outcomes then will fall within a range of one notch on either side of the indicated rating. APS' current corporate credit rating of 'BBB' stands right at the midpoint of the "Excellent" / "Aggressive" range.[9]

---

[8] S&P Research: "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.

[9] S&P Research: "Issuer Ranking: U.S. Regulated Electric Utility Companies, Strongest to Weakest," October 4, 2011.

**Table 1**

**Business And Financial Risk Profile Matrix**

| Business Risk Profile | Financial Risk Profile | | | | | |
|---|---|---|---|---|---|---|
| | **Minimal** | **Modest** | **Intermediate** | **Significant** | **Aggressive** | **Highly Leveraged** |
| Excellent | AAA | AA | A | A- | BBB | -- |
| Strong | AA | A | A- | BBB | BB | BB- |
| Satisfactory | A- | BBB+ | BBB | BB+ | BB- | B+ |
| Fair | -- | BBB- | BB+ | BB | BB- | B |
| Weak | -- | -- | BB | BB- | B+ | B- |
| Vulnerable | -- | -- | -- | B+ | B | CCC+ |

**Q. WHY IS S&P'S METHODOLOGY MEANINGFUL TO YOU?**

A. S&P's methodology helps facilitate a general understanding of how a credit rating agency carries out the process of formulating a credit rating and the factors that go into that determination.[10]

**Q. PLEASE DISCUSS HOW S&P'S METHODOLOGY PROVIDES GUIDANCE FOR THE COMMISSION IN THIS CASE.**

A. As a former head of the Fitch utility ratings practice, I certainly appreciate that the credit rating process goes beyond the mere matching up of ratios with rating ranges. However,

[10] I focus here on S&P's ratings methodology, as opposed to those at Moody's or Fitch, due to the greater transparency of S&P's ratings process owing to its explanation of the methodology and how it is implemented in published reports.

the S&P Financial Risk Indicative Ratios (Table 2 below) combined with the business and financial risk profiles (in Table 1) are very helpful with regard to indicating rating trends. The Commission can use S&P's quantitative factors (in the form of financial ratios) and qualitative assessments (in the form of a business risk profile ranking) as a guide in assessing potential credit rating outcomes for individual utility companies.

**Table 2**

**Financial Risk Indicative Ratios (Corporates)**

| | **FFO/Debt (%)** | **Debt/EBITDA (x)** | **Debt/Capital (%)** |
|---|---|---|---|
| Minimal | greater than 60 | less than 1.5 | less than 25 |
| Modest | 45-60 | 1.5-2 | 25-35 |
| Intermediate | 30-45 | 2-3 | 35-45 |
| Significant | 20-30 | 3-4 | 45-50 |
| Aggressive | 12-20 | 4-5 | 50-60 |
| Highly Leveraged | less than 12 | greater than 5 | greater than 60 |

**Q. WHERE IS APS IN THE S&P MATRIX?**

A. With S&P placing APS in the highest qualitative ranking of "Excellent," my view is that further movement for the Company toward the 'BBB+' level will only come from a financially supportive decision in this case, coupled with continued financial vigilance on the part of Company management. Or, as S&P describes it, higher ratings are:

> … contingent on financial prudence in containing costs and financing capital investments. Specifically, we may raise the ratings one notch if the company demonstrates sustained financial performance above our forecast levels of adjusted FFO to debt of 20% and adjusted debt to capital of 55%. Minimizing rate lag and earning close to authorized equity returns would help achieve such financial metrics.[11]

**Q. HOW DO YOU BELIEVE THE RATING AGENCIES WOULD REACT TO A NEGATIVE DECISION FROM THIS COMMISSION?**

A. As I explained earlier, a continuing 'Positive' outlook after an upgrade is very unusual. I expect that a less supportive decision in this case would lead S&P to lower the Company's outlook to the more normal designation of 'Stable.' That would represent a significant missed opportunity for the Commission and the Company to take actions that accrue to the benefit of both customers and investors. Moody's expects APS' rating to remain stable during the near-to-medium term, but does note that, longer term, "an upgrade could be possible if there is consistent supportive regulatory treatment resulting in material, timely rate increases." Conversely, a "downgrade could result if regulatory lag for capital spending becomes more pronounced."[12]

---

[11] S&P Research Update: "Pinnacle West Capital Corp. and Arizona Public Service Co. Ratings Raised to 'BBB', June 24, 2011.

[12] Moody's Credit Opinion: "Arizona Public Service Company," February 25, 2011.

## V. APS' PROPOSED DECOUPLING MECHANISM

**Q. IN THIS PROCEEDING, APS HAS PROPOSED AN EFFICIENCY AND INFRASTRUCTURE ACCOUNT ("EIA") MECHANISM, COMMONLY REFERRED TO AS A DECOUPLING MECHANISM. WOULD YOU SHARE YOUR VIEWS ON DECOUPLING MECHANISMS?**

A. Yes. Dating all the way back to when I was chairing the Michigan Public Service Commission, I and most industry stakeholders were stumped by the issue of how to promote energy conservation among utility customers, without jeopardizing a regulated utility's financial health. Out of this quandary came the concept of a decoupling mechanism that allows customers to benefit from energy efficiency while preserving the utility's ability to recover its fixed costs. With a goal of at least 22% in electric energy savings by 2020, this Commission summed up the proper balance that a decoupling mechanism can provide in its "Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structure," issued December 29, 2010. In that document, the ACC stated in pertinent part:

> Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency, as it establishes better certainty of utility recovery of authorized fixed costs and better aligns utility and customer interests. ...Some form of decoupling or alternative for addressing financial disincentives must be adopted in order to encourage and enable aggressive use of demand side management programs and the achievement of Arizona's Electric and Gas Energy Efficiency Standards, which will benefit ratepayers and minimize utility costs. ...
>
> While other decoupling models are appropriate in general, non-fuel revenue per customer decoupling may be well suited for Arizona as it responds to customer growth and is better suited to address the issues associated with customer growth. ...

> Commitment to and early implementation of decoupling should precede significant decoupling-specific adjustments to cost of capital .... The review of the initial three-year period following adoption of revenue per customer decoupling should include analysis and discussion of possible adjustments to cost of capital to recognize any modified risk at the utilities ...
>
> Full decoupling is preferable to partial decoupling as it contributes to greater rate stability which would encourage improvements in financial ratings, is administratively more manageable, and offers opportunities for rate relief following extreme weather events.

**Q. DO YOU AGREE WITH THE APPROACH THE ACC PROPOSES IN ITS POLICY STATEMENT?**

A. Yes I do. Decoupling has spread significantly during the past decade with Regulatory Research Associates, a respected commentator on utility regulatory policies, reporting in April 2011 that electric decoupling is being utilized in 18 states across the U.S., with gas decoupling authorized in 29 states.[13] Thus, use of decoupling is becoming more and more the norm with each passing year. To me, it is clear that if the ACC were to move forward with revenue-based decoupling consistent with its Policy Statement, such action would be wholly consistent with the national regulatory trend. In addition, holding off on any negative adjustment to cost of capital as a result of approval of decoupling makes sense until an assessment can be made of how the treatment of Arizona's electric and gas utilities with regard to decoupling compares to the situations that regulated utilities in other jurisdictions are facing.

[13] Regulatory Research Associates, "Regulatory Focus: Decoupling Mechanisms/Straight-Fixed-Variable Rate Design," April 5, 2011.

**Q. SO YOU AGREE WITH APS THAT A DECOUPLING MECHANISM SHOULD BE APPROVED WITHIN THIS RATE CASE?**

A. Yes and I note that APS witness Leland Snook has described in his testimony a proposed decoupling mechanism that tracks the ACC Policy Statement very closely. While there are small differences, Mr. Snook has explained the Company's rationale for diverging from that Policy Statement in those areas. Action on decoupling now is an appropriate step for this Commission – especially in light of its ambitious energy efficiency goals – and the APS proposal deserves serious consideration. Also, the testimony of AIC witness Dr. Daniel Hansen highlights the need for a decoupling mechanism to overcome the financial disincentive embedded in the Company's current rate design and the manner in which APS' proposal will align the utility and customer interests to achieve energy efficiency without depriving APS of a reasonable opportunity to recover its authorized rate of return.

**Q. HOW DO YOU EXPECT THE RATING AGENCIES WOULD VIEW APS' PROFILE IF THIS COMMISSION APPROVES THE COMPANY'S DECOUPLING PROPOSAL?**

A. Quite favorably. In fact, Moody's just released a Special Comment entitled "Decoupling and 21st Century Rate Making – Increased usage of decoupling mechanisms is credit positive" on November 4, 2011:

> Prospectively, we see utilities and regulators increasingly working together to find solutions that accomplish two key objectives: providing timely cost recovery for utilities and managing the all-in rate increases for

> consumers. To that end ... increasing acceptance of various revenue decoupling mechanisms accompanying energy efficiency/conservation programs, would be widely viewed to be credit positive.

## VI. APS' PROPOSED INFRASTRUCTURE ADJUSTOR

**Q. APS HAS ALSO PROPOSED AN ENVIRONMENTAL AND RELIABILITY ACCOUNT ("ERA") MECHANISM. DO YOU HAVE VIEWS ON THIS CONCEPT?**

A. As described by APS witness Mr. Snook, the ERA mechanism "is intended to recover the revenue requirement of generation plant capacity acquisitions, efficiency projects and environmental improvement projects on a more concurrent basis between rate cases." That concept is very attractive for customers, the Commission and the Company because it would encourage APS to enhance its infrastructure regularly and in a way that would reap reliability and safety gains, while simultaneously promoting the efficiency goals of this Commission. As a former regulator, I would want to be comfortable with the following aspects of the ERA before approving it: 1) are the investments covered by the ERA easier to quantify and timely reflect in rates outside the bounds of a traditional rate case; 2) are the investments undertaken between rate cases beneficial for customers; 3) are customers being called on to pay no more than actual prudent costs for those infrastructure enhancements; and 4) will the ERA minimize the need for frequent and costly base rate cases? If the answer to all of these questions is "Yes", approval of the ERA will be beneficial to all concerned.

**Q. ARE ADJUSTMENT MECHANISMS SUCH AS THE EIA AND THE ERA TARGETING PARTICULAR ASPECTS OF UTILITY OPERATIONS GAINING FAVOR WITH REGULATORS ACROSS THE U.S.?**

A. Yes. Of course, adjustment mechanisms for fuel and purchased power cost recovery are by far the norm across the U.S. They are in place in more than 40 jurisdictions. And, possibly because of the familiarity of operation and proven value of such tried-and-true mechanisms, adjustment mechanisms outside the fuel realm are becoming much more prevalent. In 2006, the Brattle Group, a respected Cambridge, Massachusetts-based energy consulting firm, prepared a report for the Edison Electric Institute on the potential for "automatic adjustment clauses" ("AACs") of all types to provide benefits to both utilities and their consumers:

> The circumstances justifying AACs as beneficial to utilities <u>and</u> their customers are more pronounced today than ever: more volatile fuel and wholesale power prices, more vertical unbundling and consequent outsourcing of supply needs, reduced credit ratings of many utilities, and an increasing number of new or emerging cost items which utilities cannot control and from which they do not profit.[14]

Evolving expense costs falling into these categories identified by Brattle include those related to DSM and energy efficiency; environmental expenditures related to control of emissions beyond those already tracked; electric and gas distribution and transmission upgrades; renewable resource development; needed infrastructure investment costs; and other costs precipitated by governmental compliance requirements. As Moody's noted in

[14] The Brattle Group, "Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations," November 2006. (Emphasis added.)

its recent "decoupling" report, "a more deliberate transition towards single-issue rate riders [and] trackers ... would be widely viewed to be credit positive."[15]

Speaking as a former bond rater, I can attest to the fact that the rating agencies view fuel and other adjustment mechanisms positively within their credit rating analyses, owing to their effect of: (1) more closely aligning prudently-incurred utility expenses with ultimate recovery of actual costs from customers; (2) reducing regulatory lag between time of expenditure and when cost recovery occurs; and (3) decreasing the number of time-consuming and costly rate cases. Good credit quality is in the best interests of both customers and shareholders. Accordingly, if the ACC finds that the Company's ERA lines up well on the questions I highlight above, I urge its serious consideration.

## VII. CONCLUSION

**Q. DO YOU HAVE CONCLUDING THOUGHTS?**

A. Yes. The concept of utility regulation is to provide a surrogate for the competitive market that is not present when a company possesses monopoly or near-monopoly status with regard to an essential good, such as utility service. The EIA decoupling mechanism and ERA infrastructure investment mechanism attempt to align the costs that a utility is required to expend by law or regulation with its recovery of those costs on a timely basis – without need for frequent rate cases to recognize regulatory mandated changes in sales levels and/or beneficial rate base additions.

[15] Moody's Research: "Decoupling and 21st Century Rate Making – Increased usage of decoupling mechanisms is credit positive," November 4, 2011.

Base rate cases with their high expense – for all participants – and lengthy duration are ill-suited to deal with cost recovery that will vary as customer energy efficiency gains are realized, or where a utility is continually undertaking plant investment to ensure reliability and safety, as well as to meet evolving environmental mandates. As compared to full-blown rate cases, the EIA and ERA mechanisms clearly will be more efficient in providing timely recovery of prudent expenditures and allow for ongoing investment without undue regulatory lag.

In closing, it is wholly consistent with rational utility economics for customers to pay the fixed costs of reliable utility service, prudently incurred, especially when such costs are affected by regulatory policies or beneficial infrastructure enhancement. Approval of the EIA and ERA mechanisms seeks to achieve that goal, by allowing recovery of actual incurred costs on a timely basis, without need for frequent rate cases. This, in turn, helps to improve the financial stability of APS, a status which will benefit all stakeholders in the regulatory process.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

**A.** Yes.

18762-9/2913368

**STEVEN M. FETTER**

P.O. Box 280
Nordland, Washington 98358
732-693-2349
RegUnF@gmail.com
www.RegUnF.com

**Education** University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. (Communications) 1974

April 2002 – Present
**President – REGULATION UnFETTERED – Henderson, NV / Nordland, WA**

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy, water and telecommunications sectors, including public utility commissions and consumer advocates; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; skills training in ethics, negotiation, and management efficiency.

Service on Boards of Directors of: CH Energy Group (Chairman, Governance and Nominating Committee; Member, Audit Committee; Previous Lead Independent Director and Chairman, Audit Committee and Compensation Committee), National Regulatory Research Institute, Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group; Participant, Keystone Center Dialogues on RTOs and on Financial Trading and Energy Markets.

October 1993 – April 2002
**Group Head and Managing Director; Senior Director – Global Power Group, Fitch IBCA Duff & Phelps – New York/Chicago**

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance; Member, Fitch Utility Securitization Team.

Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
**Consultant – NYNE – New York, Ameritech – Chicago, Weatherwise USA – Pittsburgh**

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 – October 1993
**Chairman; Commissioner – Michigan Public Service Commission – Lansing**

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant 12-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 – October 1987
**Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary – U.S. Department of Labor – Washington DC**

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 – August 1985
**Senate Majority General Counsel; Chief Republican Counsel – Michigan Senate – Lansing**

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed seven-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 – January 1983
**Assistant Legal Counsel – Michigan Governor William Milliken – Lansing**

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 – March 1982
**Appellate Litigation Attorney – National Labor Relations Board – Washington DC**

**Other Significant Speeches and Publications**

The "A" Rating (Edison Electric Institute Perspectives, May/June 2009)

Perspective: Don't Fence Me Out (Public Utilities Fortnightly, October 2004)

Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998) (unpublished)

Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)

The Feds Can Lead...By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)

Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)

Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)

Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

EXHIBIT
A/C-3
ADMITTED

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | DOCKET NO. E-01345A-11-0224 |

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

**Direct Testimony of**

**Daniel G. Hansen, Ph.D.**

**on Behalf of**

**Arizona Investment Council**

**November 18, 2011**

# TABLE OF CONTENTS



GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

## 1. INTRODUCTION

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

A. My name is Daniel G. Hansen. My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705.

**Q. WHAT IS YOUR PROFESSION AND BACKGROUND?**

A. I am a Vice President at Laurits R. Christensen Associates, Inc. I received a Ph.D. in Economics from Michigan State University in 1997, at which time I joined Laurits R. Christensen Associates, Inc. I have worked primarily with and for regulators, intervenors, and the energy industry during my 14 years of consulting experience. In recent years, I have, on several occasions, analyzed and testified on some of the key issues raised in this docket. Specifically, in 2005, I conducted independent evaluations of Northwest Natural Gas's decoupling and weather normalization mechanisms in Oregon, as required by that Commission's orders approving the mechanisms. In 2007, I provided testimony on behalf of the Utah Division of Public Utilities regarding Questar Gas Company's decoupling mechanism. On behalf of Environment Northeast (a non-profit environmental organization), I provided testimony regarding a decoupling mechanism proposed by Connecticut Light & Power and also served on a panel before the Massachusetts Department of Public Utilities to discuss the merits of decoupling mechanisms (Docket No. 07-50). In 2009, I conducted an independent evaluation of decoupling mechanisms in place at New Jersey Natural Gas and South Jersey Gas. Most recently, I was retained and am in the process of evaluating Columbia Gas of Ohio's pilot

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

program concerning the implementation of straight fixed variable pricing. My resume is attached as AIC Exhibit DGH-1.

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

A. The Arizona Investment Council ("AIC") has retained Christensen Associates Energy Consulting, LLC, a subsidiary of Laurits R. Christensen Associates, Inc., to provide testimony regarding the Efficiency and Infrastructure Account ("EIA") proposed by Arizona Public Service Company ("APS" or the "Company"). My testimony describes the reasons why AIC strongly supports the adoption of the EIA.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. Following this introduction, I will describe:

- Section 2: Why the EIA is needed;
- Section 3: How the EIA works;
- Section 4: How the EIA is consistent with the ACC's December 28, 2010 Decoupling Policy Statement[1] and other revenue decoupling mechanisms currently in use;
- Section 5: Why the EIA is preferred to alternative methods of addressing the throughput incentive problem;
- Section 6: The impact of the EIA on APS' customers; and
- Section 7: Summary of my analysis and recommendations.

[1] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures (the "Policy Statement").

## 2. <u>THE COMPANY'S NEED FOR THE EIA</u>

**Q. WHAT IS THE PURPOSE OF A DECOUPLING MECHANISM?**

A. Decoupling mechanisms are primarily intended to reduce or eliminate a utility's strong financial disincentive to promote conservation and energy efficiency. For this reason, environmental organizations such as the Natural Resources Defense Council and Environment Northeast support decoupling. Decoupling mechanisms also reduce the variability of utility revenue which is intended to allow them to recover their fixed costs ("fixed-cost revenue"). In the case of APS' proposed EIA, the Company would recover a fixed amount of revenue per customer served.

**Q. PLEASE DESCRIBE THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY THAT EXISTS UNDER ITS CURRENT RATES.**

A. The disincentive is created because traditional rate designs require the utility to recover the majority of its fixed costs, such as distribution costs, through volumetric rates. A reduction in sales leads to a reduction in revenue, but it does not lead to a similar reduction in costs. Therefore, under traditional rate design, the Company's realized rate of return is tied to commodity sales levels. Lower kWh sales levels lead to a lower rate of return and higher sales levels lead to a higher rate of return. This traditional design is, at best, a game of chance as to whether customer usage patterns will actually allow the utility to recover its fixed costs. Those costs remain constant regardless of how much or how little energy is actually used. Moreover, the tie between its opportunity to recover fixed costs and the level of customer usage of electricity incentivizes the Company to encourage increased use per customer, not conservation.

**Q. IS REVENUE DECOUPLING RELEVANT FOR APS GIVEN ITS CURRENT CIRCUMSTANCES?**

A. Yes. There are two factors that make revenue decoupling particularly important to and relevant for APS. First, this Commission has established a requirement to reduce electricity sales by 22% by 2020. Second, APS recovers a very large share of its fixed costs through volumetric rates. Specifically, APS witness Mr. Leland Snook testified that, for residential customers in the 2010 test year, 73% of APS' fixed costs were recovered through a volumetric rate.[2]

The fact that a large share of APS' fixed costs are recovered through per-kWh rates means that – absent a change in the way those costs are recovered – APS has a significant disincentive to support the conservation goal established for Arizona. The use of revenue decoupling via the EIA will align APS' interests with the interests of its customers, making it more likely that the Company will meet the conservation mandate.

As or perhaps more importantly, even if we assume that APS can overcome its disincentive and effectively implement energy efficiency programs without a decoupling mechanism, the EIA remains relevant on fairness grounds. Without a modification to the rate design, APS will continue to incur fixed costs, but will be unable to recover them because of the significant reductions in energy usage. Without the EIA, the Company is no longer being afforded a realistic opportunity to earn its authorized rate of return.

---

[2] Direct Testimony of Leland R. Snook, p. 3.

**Q. HOW DOES THE EIA ADDRESS THE COMPANY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY?**

A. The EIA removes the link between the Company's sales and revenue. Under the EIA, APS recovers the level of revenue per customer approved by the Commission in this rate case, regardless of the level of sales per customer. Therefore, when the EIA is in place, the Company's realized rate of return is not adversely affected by the success of required and Commission-approved conservation or energy efficiency programs. In my experience, the removal of this disincentive changes the way utilities operate, making them active advocates of energy efficiency and increasing customer satisfaction ratings.

## 3. <u>OVERVIEW OF APS' PROPOSED DECOUPLING MECHANISM</u>

**Q. PLEASE DESCRIBE THE EIA.**

A. The EIA is a revenue per customer decoupling mechanism in which the Company's *allowed* revenue toward the recovery of fixed costs is equal to the allowed revenue per customer (calculated using test year data) multiplied by the number of customers served in the current year (based on the average number of customers across billing months). The EIA compares the *allowed* revenue to the *actual* revenue billed. Any difference is used to adjust rates in the following year. An over-recovery of fixed-cost revenue (i.e., when actual revenue exceeds allowed revenue) produces a reduction in customer rates in the following year. An under-recovery of fixed-cost revenue (i.e., when actual revenue is less than allowed revenue) produces an increase in customer rates in the following year.

**Q. HOW ARE RATES ADJUSTED TO ACCOUNT FOR THE DIFFERENCE BETWEEN ALLOWED AND ACTUAL REVENUE?**

A. The EIA rate adjustments are set to ensure that each eligible rate class receives the same percentage change in rates. The percentage change is determined by first calculating the difference between allowed and actual revenue and then dividing that difference by total Company revenue. The percentage adjustment is applied to certain billing components (i.e., the customer charge, energy rates and demand charges) of eligible customer bills resulting in either a surcharge or customer credit. The EIA contains a 3% cap on the surcharge, but no cap on customer credits, i.e., how much the customer's bill can go down.

## 4. <u>CONSISTENCY WITH THE COMMISSION'S POLICY STATEMENT AND THE NATIONWIDE MOVE TOWARD DECOUPLING</u>

**Q. HAS THE REVENUE PER CUSTOMER DESIGN PROPOSED BY APS BEEN USED IN OTHER JURISDICTIONS?**

A. Yes, the revenue per customer design is the most common form of decoupling that I have observed. The per-customer concept has been used by several utilities throughout the country, including United Illuminating in Connecticut; Idaho Power; Delmarva Power in Maryland; Detroit Edison in Michigan; Portland General Electric in Oregon; PEPCO in Washington DC and Maryland; and Wisconsin Public Service Company. Although each decoupling mechanism has its own design and implementation characteristics, they are all based on allowed revenue per customer.

**Q. IS THE EIA CONSISTENT WITH THE COMMISSION'S POLICY STATEMENT?**

A. Yes, the EIA proposed by APS is consistent with the Policy Statement, including the following design attributes:

- The use of a revenue per customer design;[3]
- Implementation as a full, non-pilot program;[4]
- Full decoupling, as opposed to partial decoupling;[5]
- The inclusion of weather effects in decoupling deferrals;[6]
- Broad participation across customer classes;[7]
- Decoupling adjustments are blended across customer classes;[8] and
- The use of a 3% cap on rate increases.[9]

The Policy Statement was the result of careful consideration on the part of the ACC, which included three stakeholder workshops and a study conducted by the Lawrence Berkeley National Laboratories. APS obviously took this process seriously by aligning its proposed EIA so closely with the recommendations of the Policy Statement.

[3] Policy Statement, Statement 4, p. 30.
[4] Policy Statement, Statement 5, p. 30.
[5] Policy Statement, Statement 8, p. 31.
[6] Policy Statement, Statement 9, p. 31.
[7] Policy Statement, Statement 11, p. 31.
[8] Policy Statement, Statement 12, p. 31.
[9] Policy Statement, Statement 14, pp. 31-32.

**Q. WHAT ARE YOUR THOUGHTS REGARDING APS' ANALYSIS OF THE APPROPRIATE RETURN ON EQUITY ("ROE") IN LIGHT OF THE DECOUPLING MECHANISM?**

A. As explained by Mr. Snook, APS is proposing that no automatic adjustment be made to the Company's ROE simply due to the adoption of the EIA.[10] Consistent with the Policy Statement, AIC agrees that there should be no downward adjustment. Further, contrary to the notion that a decoupling mechanism allows a utility to operate "risk free," the reality is that the Company continues to face substantial risks associated with, among other things, changes in the economy, regulatory or environmental policy shifts and increased costs that are outside APS' control.

## 5. <u>ANALYSIS OF OTHER ALTERNATIVE RATE DESIGNS</u>

**Q. ARE ALTERNATIVES TO REVENUE DECOUPLING AVAILABLE FOR ADDRESSING THE UTILITY'S DISINCENTIVE TO PROMOTE CONSERVATION AND ENERGY EFFICIENCY?**

A. I am familiar with two primary alternatives: Straight-Fixed Variable ("SFV") pricing and Lost Revenue Adjustment ("LRA") mechanisms.

**Q. PLEASE DESCRIBE LRA MECHANISMS.**

A. LRA mechanisms attempt to compensate the utility only for revenue lost because of utility-sponsored conservation and energy efficiency programs. An LRA mechanism accomplishes this through measurements (or estimates) of usage reductions linked to

[10] Direct Testimony of Leland R. Snook, pp. 22-23.

specific utility-sponsored programs. It then compensates the utility for the fixed-cost revenue lost because of those usage reductions.

**Q. WOULD YOU RECOMMEND THE USE OF AN LRA MECHANISM FOR APS?**

A. No. LRA mechanisms have several disadvantages when compared to the EIA. First, because the LRA mechanism ties the level of utility revenue directly to estimates of program-based usage reductions, those estimates become fertile ground for significant disputes. These disputes increase costs to ratepayers and shareholders and likely will reduce the utility's confidence that lost revenue will be recovered, which reduces its incentive to fully support those programs.

Second, LRA mechanisms do not address the utility's financial incentive to *increase* customer usage levels. Under its current rate structure, APS has an incentive to encourage load growth in order to increase its revenues and, by doing so, better cover its fixed costs. Under an LRA mechanism, the utility continues to receive more revenue from increased customer usage as well as from successful energy efficiency programs. In contrast, revenue decoupling removes the link between sales and revenue, so that the utility is financially indifferent to increases *and* decreases in customer usage.

Third, LRA mechanisms may limit the range of energy efficiency programs that the utility is willing to support. Because LRA mechanisms require estimates of usage reductions, programs for which the usage reductions are not easily measured are unlikely to be supported by the utility. For example, marketing materials or a web site that provides conservation tips may be effective in getting customers to adopt conservation measures, but it may not be possible for the utility to demonstrate how many customers acted on the materials or the actions that customers took based on them.

In contrast, revenue decoupling does not require measurements of program-specific load reductions, so the utility can be confident that any positive effects associated with marketing materials or its web site will be addressed through the decoupling mechanism.

**Q. PLEASE DESCRIBE SFV PRICING.**

A. SFV pricing uses fixed monthly charges to recover all fixed costs. The adoption of SFV pricing would lead to a significant increase in the monthly customer charge and a reduction in the volumetric rates, relative to current rates. As Mr. Snook states in his testimony,[11] that charge for residential service would have to be increased to more than $90 per month for APS to have the opportunity to recover its fixed costs while also meeting the 22% conservation requirement.

**Q. WOULD YOU RECOMMEND THE USE OF SFV PRICING FOR APS?**

A. No. While both revenue per customer decoupling and SFV pricing accomplish the goal of removing the link between utility sales and revenue, obviously SFV pricing leads to very large bill increases for low-use customers. To the extent that low-use customers are also low-income customers, SFV would adversely affect customers who can least afford to deal with bill increases. In addition and as importantly, by reducing the per-kWh rate, SFV pricing reduces each customer's incentive to conserve energy.

[11] Direct Testimony of Leland R. Snook, p. 8.

In contrast, the EIA does not alter the relationship between fixed charges and volumetric rates, so it does not affect bills according to customer usage levels. In addition, the EIA does not reduce the customer-level incentive to conserve.

## 6. <u>EIA IMPACT ON CUSTOMERS</u>

**Q. PLEASE DESCRIBE WHY DECOUPLING DOES NOT REDUCE THE RATEPAYERS' INCENTIVE TO ENGAGE IN CONSERVATION OR ENERGY EFFICIENCY.**

A. Decoupling has no detrimental effect on an individual ratepayer's incentive to conserve energy and it may actually increase the customer-level incentive to conserve. This is because the only thing a ratepayer can control is whether he or she engages in conservation or energy efficiency activities and the customer's own activities do not lead to decoupling deferrals that are large enough to change rates.

When the customer engages in conservation efforts, he or she receives the immediate benefit of a reduced bill. That individual's incentive to conserve is not directly affected by the "true-up" of fixed-cost revenue that is lost as a result of his or her individual conservation because the true-up in the following year is spread across the entire pool of several hundred thousand eligible customers. Also, while decoupling could lead to an increase in rates in a year following significant conservation by enough customers, that higher rate only *increases* the individual customer-level incentive to engage in long-term conservation and energy efficiency activities.

**Q. IT SEEMS COUNTER-INTUITIVE THAT DECOUPLING COULD INCREASE THE CUSTOMER-LEVEL INCENTIVE TO CONSERVE. PLEASE EXPLAIN THIS IN MORE DETAIL.**

A. Yes. Consider an example in which a conservation program causes 20% of the customers to reduce usage by 10% each, which would lead to a 2% decrease in total usage (= 0.2 x -0.1). Assume that this leads to a reduction in fixed-cost revenue of 2% (this is an over-estimate because some fixed-cost revenue is recovered through fixed charges). All of the customers, including the 20% who conserve and the 80% who do not, will pay the standard tariff rates in the current year. In the following year, the fixed-cost portion of the retail rates increases by approximately 2% for all customers. This rate increase actually *increases* an individual customer's incentive to conserve in the following year.

While it may seem counter-intuitive that decoupling increases the customer-level incentive to conserve, consider the decision-making process for one customer. Suppose that this customer knows that (1) the conservation program is in place, (2) it will likely lead others to reduce their usage levels and (3) therefore the program will cause a slight increase in rates in the following year. The customer in this example will pay the higher rate in the following year regardless of whether he or she chooses to conserve. Therefore, the customer will evaluate the benefits of conserving energy by considering the immediate bill benefit in the current year, as well as the small rate increase in the following year caused by class-wide conservation. This *increases* the incentive (relative to current rates in the absence of decoupling) to engage in long-term conservation activities.

**Q. HOW ELSE MIGHT THE EIA POSITIVELY IMPACT APS' CUSTOMERS?**

A. As explained in the testimony of AIC witness Steven Fetter, credit rating agencies and the financial community view the adoption of the EIA as a favorable event. An improved credit rating will lead to better access to capital, both with regard to timing and terms. That, in turn, benefits ratepayers as well as investors.

## 7. SUMMARY

**Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE EIA?**

A. I recommend that the Commission approve the EIA. The EIA removes a disincentive that APS faces in supporting conservation and energy efficiency programs. The EIA has several advantages relative to alternative methods of addressing the Company's disincentive to promote conservation and energy efficiency, including:

- Minimizing bill impacts on customers;
- Increasing the customer-level incentive to conserve;
- Eliminating the Company's incentive to *increase* customer usage levels; and
- Instead, encouraging APS to support the full range of energy efficiency programs and public policies.

Finally, the EIA will afford APS an opportunity to recover its fixed costs, while the traditional rate design, coupled with the Commission's energy efficiency mandates, will not.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| 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-11-0224 |

EXHIBIT
AIC-4
~~ADMITTED~~

**Testimony of**

**Gary M. Yaquinto**

**in Support of Settlement Agreement**

**on Behalf of**

**Arizona Investment Council**

**January 18, 2012**

## TABLE OF CONTENTS

## 1. INTRODUCTION

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

A. Gary M. Yaquinto. I am the President of the Arizona Investment Council ("AIC"). Our offices are located at 2100 North Central Avenue, Phoenix, Arizona 85004.

**Q. Have you filed testimony previously in this proceeding?**

A. Yes, I filed direct testimony on November 18, 2011.

**Q. What is the purpose of this testimony?**

A. My testimony is offered to explain AIC's support for the Proposed Settlement Agreement filed by Staff on January 6, 2012 ("Settlement Agreement").

## 2. SETTLEMENT AGREEMENT

**Q. Is AIC a signatory to the Settlement Agreement?**

A. Yes. We participated with the other signatories in the discussion and negotiations which led to the execution of the Settlement Agreement by almost all intervenors in the case. We also participated in the meetings arranged by APS to discuss technical aspects of the Company's filing. All meetings convened to discuss the application and to negotiate the Settlement Agreement were transparent and open to all intervenors.

**Q. Generally, why does AIC support the Settlement Agreement?**

A. AIC supports the Settlement Agreement because it contains provisions that are fair to and benefit APS, its customers, its investors and the public in general.

Specifically, the Settlement Agreement builds on the progress established in APS' last case by improving the Company's financial condition so it can compete in attracting capital for investments to meet the needs of its customers. By keeping the base rate essentially at an even level and then incorporating an opportunity to gradually adjust rates for some cost increases during the four-year moratorium period, customers will enjoy substantial rate stability and the potential for future rate shock is minimized.

The benefits to investors include greater certainty and the potential for lower earnings attrition than would otherwise occur during the four-year moratorium. Other provisions in the Settlement Agreement that are of particular importance to AIC are:

- Changes in the Fuel Power Supply Adjustor to remove the 90/10 sharing provision;
- A possible rate adjustment for APS' acquisition of Southern California Edison's share of Four Corners Units 4 and 5, if approved by the Commission;

- A modification to the Environmental Improvement Charge by resetting it to zero and enabling APS to recover on a more timely basis some of the carrying costs of its investments in government-mandated environmental controls; and
- A cost deferral related to near-term changes in Arizona property tax rates.

Also, as AIC expert witness Steve Fetter states in his testimony, the Settlement Agreement, if approved by the Commission, will likely be viewed favorably by rating agencies as they consider possible revisions to APS' bond ratings. This should afford the Company better access to capital at more attractive rates.

**Q. What is AIC's view of the Lost Fixed Cost Recovery ("LFCR") mechanism included in the Settlement Agreement?**

A. Inclusion of the LFCR mechanism – which will enable the Company to recover lost fixed cost revenue due to mandated reductions in sales primarily attributable to energy efficiency programs – was an essential component of the Settlement Agreement from AIC's standpoint. While the LFCR differs from our preferred methodology of full revenue decoupling, it nevertheless is an acceptable approach under the circumstances of this case and one supported by all signatories. In addition to enabling the Company to recover some lost fixed cost revenue, it provides customers the assurance that adjustments will be capped at one percent, as well as the opportunity to opt out of the LFCR and elect an alternative rate structure instead.

**Q. Are there any other reasons for AIC's support of the Settlement Agreement?**

A. Yes. The Settlement Agreement responds to the Commission's expressed desire to maintain flexibility as it considers such agreements in connection with rate cases. AIC continues to believe that settlement agreements provide opportunities for creative solutions among parties that otherwise would not be available through litigated proceedings. Settlements like the one reached in this case also help streamline the regulatory process and lower costs to all parties, which improves the overall regulatory environment.

Finally, as discussed in my direct testimony, APS is Arizona's largest electric utility and a major contributor to our State's economy. Approval of the Settlement Agreement will support APS' continued financial health – that has a positive, reverberating impact throughout Arizona in the form of jobs, taxes and income.

## 3. RECOMMENDATION

**Q. Mr. Yaquinto, what is AIC's recommendation for the Commission in relation to the Settlement Agreement?**

A. The Settlement Agreement represents an appropriate, productive balance among the often widely divergent views of the parties on a broad and challenging set of issues. In reaching that accord, the process was open and transparent and the result reflects give and take on the part of all participants. It builds on progress from the last rate case and should give the Company a realistic opportunity to recover its prudent costs and earn a reasonable rate of return over the next four years. We recommend the Commission enter its Order approving the Settlement Agreement.

**Q. Does that conclude your testimony?**

A. Yes, it does.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| 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-11-0224 |

EXHIBIT
AIC-5
~~ADMITTED~~

**Testimony of**

**Steven M. Fetter**

**in Support of Settlement Agreement**

**on Behalf of**

**Arizona Investment Council**

**January 18, 2012**

## TABLE OF CONTENTS

## INTRODUCTION

**Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.**

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is P.O. Box 280, Nordland, Washington 98358.

**Q. PLEASE BRIEFLY SUMMARIZE YOUR EMPLOYMENT EXPERIENCE.**

A. As mentioned, I am currently the President of Regulation UnFettered, a utility advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc., a credit rating agency based in New York and London. Before that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC").

**Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS DOCKET BEFORE THE ARIZONA CORPORATION COMMISSION ("COMMISSION" OR "ACC")?**

A. Yes. I filed direct testimony on behalf of the Arizona Investment Council on November 18, 2011.

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

A. Based upon my experience as a state utility regulator, bond rater, and consultant for regulated utilities, public utility commissions, and consumer advocates, I will focus on the following two issues:

a) the positive nature of a rate case being resolved through settlement by the contesting parties, followed by regulatory review and approval; and

b) the balanced nature of the terms within the Proposed Settlement Agreement filed in this docket on January 6, 2012 ("Settlement Agreement"), which has been signed by a very diverse group of 22 parties to this case.

## <u>SETTLEMENT AGREEMENT</u>

**Q. DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT THE SETTLEMENT AGREEMENT?**

A. Yes. I find it a thoughtful and creative package of provisions that: (1) are well-balanced across a disparate group of interests, (2) are likely to be well-received by the investment community and rating agencies in continuing to move APS away from the junk status precipice it was poised upon only a few years ago, and (3) afford the Commission considerable flexibility in fashioning energy policies.

**Q. PLEASE EXPAND ON YOUR STATEMENT ABOUT THE POSITIVE NATURE OF RATE CASES BEING RESOLVED THROUGH SETTLEMENT BY CONTESTING PARTIES.**

A. During my tenure as Chairman of the Michigan PSC, my fellow commissioners and I always sought to strike a fair balance between competing policy positions in a contested rate case record in a way that furthered the public interest of the State of Michigan. But, what we could not do with certainty in that contested case context was determine the values that each contesting party placed upon each component of the positions argued. It was only through a proceeding on a proposed settlement agreement like this one that we, as regulators, could see the manner in which those parties had struck a fair balancing of their competing positions. The parties' resolution of individual contested issues removed, for the moment, our need to prioritize or make value determinations on those issues. That left us a greater opportunity to evaluate the most important issue – whether the terms of the agreement as a whole were consistent with the public interest. Accordingly, in my role as chairman, I encouraged the Michigan PSC staff to facilitate settlement among competing parties in order to achieve the substantive and procedural benefits that can result from a contested case being concluded by expeditious settlement.

**Q. BASED UPON YOUR LONG AND DIVERSE EXPERIENCE WITHIN THE UTILITY SECTOR, DO YOU SEE A FAIR BALANCING OF COMPETING UTILITY AND CONSUMER INTERESTS WITHIN THE SETTLEMENT AGREEMENT?**

A. Yes, I do.

**Q. PLEASE EXPLAIN.**

A. First, let me focus on the key consumer benefits of the Settlement Agreement – all of which I view as very positive and significant provisions:

a) It is quite rare when a rate case concludes with a zero or negative base rate and bill impact result. Not only does the Settlement Agreement here produce that unusual result (¶¶ 3.1 and 4.1), it also provides that rates will not rise for any reason during all of 2012 (such as through the operation of adjustment mechanisms) (¶ 4.3). Moreover, the agreement also includes a four-year rate case filing stay-out, ensuring that APS' base rates will not go up prior to July 1, 2016 (¶ 2.1);

b) The Settlement Agreement terms also subject APS, at its own expense, to periodic audits to "incent prudent fuel and power procurement and use" (¶ 7.4). Similarly, the Company has agreed to pay for an independent evaluation of its demand-side management programs and associated energy savings, at the sooner of either its next rate case or the passage of five years after a final order in this case (¶ 9.14(e));

c) The Settlement Agreement commits APS to interact with stakeholders on issues related to "bill presentation with a goal of making the bill easier for customers to understand" (¶ 16.1); and

d) A process is also established through which APS, Staff and stakeholders will interact with the aim of developing and filing for ACC consideration "a new performance incentive structure by December 31, 2012 that optimizes the connection between energy efficiency, rates and utility business incentives and that creates a clear connection between the level of performance incentive and the achievement of cost-effective energy savings" (¶ 9.14(d)). The goal of that process is to seek to ensure a fair balance between any incentives earned by APS and the consumer benefits produced by the programs.

**Q. DO YOU BELIEVE THOSE CONSUMER-FOCUSED PROVISIONS ARE BALANCED WHEN VIEWED IN THE CONTEXT OF THE BENEFITS THAT THE COMPANY WILL RECEIVE?**

A. Yes, I do. In that regard, let me review certain Settlement Agreement provisions that are beneficial for APS, which the rating agencies and financial markets will view as positive for the Company's credit profile:

a) Section IX of the Settlement Agreement proposes a Lost Fixed Cost Recovery ("LFCR") mechanism to provide revenue support for load lost as a result of the Company's energy efficiency ("EE") and distributed generation ("DG") activities which are being undertaken consistent with Commission directives. While the financial community would prefer a full decoupling policy – one that would allow fixed cost recovery for a broader set of load loss factors – I am confident the LFCR will be viewed as a constructive step in encouraging APS to move forward successfully in implementing EE and DG initiatives, while minimizing the negative financial consequences associated with such efforts;

b) Three provisions are included in the Settlement Agreement which address regulatory lag. Fifteen months of "Post-Test Year Plant" is allowed (¶ 3.1) – a policy that goes a long way toward mitigating negative effects related to use of a historic test year. Similarly, revisions to the Environmental Improvement Surcharge ("EIS") provide that "when APS invests capital to fund any government-mandated environmental controls, the EIS will recover the associated capital carrying costs, subject to [the current EIS] cap ..." (Section XI). This provision also diminishes regulatory lag negatives, because such investments traditionally have had to await the next rate case before their costs could be recovered. The potential that rates can be adjusted during the four-year stay-out due to a future acquisition by APS (with ACC approval) related to certain Southern California Edison generation assets (Section X) also mitigates regulatory lag;

c) The 90/10 sharing provision in the Company's Power Supply Adjustor is being eliminated (¶ 7.3). This will align cost recovery with the actual fuel and purchased power costs incurred and expended by APS; and

d) Finally, deferring for future recovery or refund from customers any property tax changes as a result of the rate increasing or decreasing from the test year level (but not changes in the assessed value of property) is a modification that seeks to align cost recovery or refund with actual cost levels that are incurred, rather than fixing them at a historic test year level (Section XII).

**Q. WHILE THESE PROVISIONS ARE THOUGHT OF AS SETTLEMENT AGREEMENT BENEFITS FOR THE COMPANY, DO THEY ALSO HAVE POSITIVE CONSEQUENCES AND RATE IMPACTS FOR CONSUMERS?**

A. Yes, they do. Adjustments which minimize the effects of regulatory lag, like the post-test year plant inclusion, moderate customer rate increases by reducing the level of expense recovery which is "postponed" to the next rate case. Consequently, they smooth the size of necessary rate adjustments and mitigate the need for larger, future rate increases. More important, though, because such adjustments are viewed favorably by rating agencies, customers benefit from the lower debt costs that stronger APS credit ratings can produce. As I pointed out in my direct testimony, a positive result in this rate case, following the constructive

2009 settlement, could well produce another ratings upgrade for APS. That also would provide additional downside protection for APS in these volatile economic times and, accordingly, protection for its customers as well.

**Q. HAVE YOU REVIEWED THE COST OF CAPITAL SECTION OF THE AGREEMENT AND, IF SO, CAN YOU OFFER YOUR THOUGHTS?**

A. Yes, I have. The authorized return on common equity ("ROE") of 10% (¶ 5.2) falls somewhat below recent ROE awards in other jurisdictions for vertically integrated electric utilities, while the 53.94% equity component within APS' capital structure (¶ 5.1) is consistent with a level that should continue to allow the Company to improve its financial condition and credit ratings over time. Accordingly, I find those two provisions of the Settlement Agreement to be a fair accommodation between the positions put forward by the parties.

## CONCLUSION

**Q. WHAT ARE YOUR CONCLUDING THOUGHTS?**

A. Taken as a whole, I see a Settlement Agreement which came together through give and take by all signatories and which strikes a balance *based upon the values that the contesting parties placed on the issues in dispute*. This Commission now has the opportunity to focus on the key issue – whether the Settlement Agreement as a whole aligns with the public interest of the State of Arizona. Based upon my 25-year involvement within the regulated utility sector, I believe that the

Settlement Agreement's provisions clearly represent a good faith effort on the part of contesting parties to compromise on their competing positions in a fair manner and, in several instances, to produce benefits that a fully litigated case rarely can achieve. I believe close Commission review should produce a conclusion that the Settlement Agreement is reasonable vis-à-vis the public interest and that it should be approved.

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

A. Yes, it does.

EXHIBIT
AECC-1

# BEFORE THE ARIZONA CORPORATION COMMISSION

| | | |
|---|---|---|
| In the Matter of the Application of Arizona | ) | |
| Public Service Company for a Hearing to | ) | |
| Determine the Fair Value of the Utility | ) | |
| Property of the Company for Ratemaking | ) | Docket No. E-01345A-11-0224 |
| Purposes, to Fix a Just and Reasonable | ) | |
| Rate of Return Thereon, to Approve Rate | ) | |
| Schedules Designed to Develop Such Return | ) | |

**Direct Testimony of Kevin C. Higgins**

**on behalf of**

**Freeport-McMoRan Copper & Gold Inc. and**

**Arizonans for Electric Choice & Competition**

**Revenue Requirement**

**November 18, 2011**

# DIRECT TESTIMONY OF KEVIN C. HIGGINS

## TABLE OF CONTENTS

# DIRECT TESTIMONY OF KEVIN C. HIGGINS

## INTRODUCTION

**Q. Please state your name and business address.**

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

**Q. On whose behalf are you testifying in this proceeding?**

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

**Q. Please describe your professional experience and qualifications.**

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

**Q. Have you testified before this Commission in other dockets?**

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on the Arizona Public Service Company ("APS") 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13]

---

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.

TEP's request to amend Decision No. 62103 (2007),[14] the 2007 TEP rate case (2008),[15] and the APS 2008 rate case (2008).[16]

**Q. Have you testified before utility regulatory commissions in other states?**

A. Yes. I have testified in approximately 135 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

A more detailed description of my qualifications is contained in Appendix A, attached to this testimony.

## OVERVIEW AND CONCLUSIONS

**Q. What is the purpose of your testimony in this phase of the proceeding?**

A. My testimony addresses five major topics:

(1) APS's request for a base rate increase of $95.5 million relative to test year base revenues;

(2) The appropriate level of nuclear decommissioning costs recovered from customers through the System Benefits Charge;

---

[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.

(3) APS's proposal to change the sharing mechanism in the Power Supply Adjustor ("PSA");

(4) APS's proposal for adoption of a revenue decoupling mechanism; and

(5) APS's proposal for adoption of an Environmental and Reliability Account. In my testimony, I recommend adjustments to APS's proposals that I believe are necessary to ensure results that are just and reasonable.

Relative to the wide scope of this general rate proceeding, my recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue. In particular, AECC is not filing testimony on the subject of allowed return on equity, in that AECC anticipates that this subject will be addressed by Staff and RUCO. The absence of specific AECC testimony on this subject should not be construed as support for the 11.0% return on equity proposed by APS in this proceeding.

**Q. What are the primary conclusions and recommendations presented in your testimony?**

A. (1) I recommend that APS's revenue requirement for its base rates be reduced by at least **$75.392** million relative to the $95.494 million base rate increase proposed by APS in its Application. This reduction does not take into account adjustments that may be offered by other parties with respect to return on equity or other revenue requirement items not addressed in my testimony.

(2) I recommend that APS's System Benefits Charge be reduced by $8.704 million per year to better reflect the reduction in decommissioning costs associated with the Palo Verde Nuclear Generating Station life extension.

(3) I recommend that APS's proposed elimination of the 90/10 sharing provision in the PSA be rejected by the Commission. If the Commission is interested in revisiting the question of the appropriate sharing proportions in the PSA, then I strongly encourage the Commission to consider adopting the 70/30 sharing proportion that was recently approved in Wyoming and Utah.

(4) I recommend that the Commission reject APS's decoupling proposal for all customers. If, however, some form of revenue decoupling is approved by the Commission, I recommend that customers with billing demands greater than 400 kW (i.e., Rate Schedules 32-L, 34, and 35) be excluded from the program. Rate Schedules 34 and 35 already have rate designs that insulate APS from loss of fixed-cost recovery from energy conservation. The design of Rate Schedule 32-L can be modified to achieve a comparable result.

(5) APS's proposed Environmental and Reliability Account is an example of unwarranted single-issue ratemaking, and should be rejected by the Commission.

## ADJUSTMENTS TO BASE REVENUE INCREASE

**Q. What increase in base revenues is APS recommending in this case?**

A. In its Application, APS is recommending a base rate increase of $95.5 million relative to test year base revenues. This increase includes the net effects of two important components: (1) a $143.5 million decrease in fuel expense included in base rates; and (2) an increase of $44.9 million from transferring the revenue requirements of certain utility-owned renewable energy projects from the RES Tariff into base rates. After netting the effects of these two components, the non-fuel base rate increase embedded in APS's proposal amounts to $194.1 million. In addition, APS has indicated in discovery responses that the Company intends to make several adjustments to its proposal, collectively reducing its filed request to increase base rates by $10.6 million to $84.9 million, as will be discussed later in my testimony. For presentation purposes, the revenue requirements adjustments in my testimony will be applied to the revenue requirements presented in APS's filed Application.

**Q. Do you have any recommended adjustments to APS's proposed base rate increase?**

A. Yes. I am recommending a reduction of $75.392 million to APS's proposed base rate increase relative to the Company's Application. This recommendation is summarized in Attachment KCH-1 and consists of the following adjustments, each of which will be discussed in turn:

**Table KCH-1**

**Summary of AECC Adjustments to APS Revenue Requirements**
**(Base Rates)**

| | Original Cost Increase/ (Decrease) | Fair Value Increase/ (Decrease) | Total Increase/ (Decrease) | Total Adjustment Impact |
|---|---|---|---|---|
| APS - As Filed Requested Increase | $ 54,610 | $ 40,884 | $ 95,494 | |
| APS - Identified Updates | 42,646 | 42,263 | 84,909 | (10,585) |
| AECC Post-Test Year Plant Adjustment | 3,660 | 50,257 | 53,917 | (30,992) |
| AECC Sales Growth Adjustment | (20,227) | 50,257 | 30,030 | (23,887) |
| AECC Renewable Generation Above Market Adj. | (32,891) | 52,993 | 20,102 | (9,928) |
| AECC Adjustment Total | | | | $ (75,392) |

*APS-Identified Update Adjustments*

**Q. What adjustments to its filed case has APS identified in discovery?**

A. In discovery, APS has identified eight changes to its filed case that the Company indicates it supports going forward. These changes relate to the Company's post-test year plant additions, payroll annualization, property tax expense, base fuel and purchased power expense, research and development project costs, step-up transformer costs, cash working capital, and APS's proposed fair value increment. Collectively, these changes reduce APS's proposed revenue requirement by **$10.585** million to $84.909 million.

**Q. What is your recommended treatment of these APS-identified changes?**

A. I recommend that the Commission accept these APS-identified changes as the revised "starting point" for APS's requested revenue requirement. Accordingly, I have provided an adjustment in my testimony for these changes as the first revenue requirement adjustment that I am recommending. This adjustment is presented in Attachment KCH-1, page 2, columns (d) and (e).

*Post-Test Year Adjustments*

**Q. What is meant by the term "test year" as used in ratemaking?**

A. "Test year" refers to a discrete twelve-month period that is used as the basis for setting utility rates in a general rate proceeding. This term is often used interchangeably with the term "test period," although some jurisdictions make a fine distinction between the two, with "test year" referring to the baseline period for which underlying historical financial and operating data must be reported and "test period" referring to the twelve-month period used for setting rates. When this distinction is made, test year and test period can be coterminous, overlapping, or entirely distinct time periods.

**Q. What test year is APS using in its application?**

A. Officially, the test year that APS is using for revenue requirement purposes is Calendar Year 2010. As such, APS begins its analysis by presenting a Calendar Year 2010 baseline that sets out the Company's twelve-month revenue, expense, and investment levels. These results are then adjusted for ratemaking purposes, which is typical in most general rate proceedings. However, in most ratemaking contexts, the test period analysis that results from such adjustments can be readily described with reference to a discrete time period, e.g., "2010 historical test year with known and measureable changes through 12/31/11," or "2011 projected test period," etc.

APS's filing defies such a clear description. While the basis of the Company's filing starts with 2010 actual revenues, expenses, and investment, the filing incorporates various revenue, expense, and investment elements that are adjusted for values that either occurred or are projected to occur variously in 2011 or 2012, but without adhering to a consistent time frame for all adjustments. The disparate time frames used by APS for its test period adjustments are highlighted in Table KCH-1, below, which identifies the time period applicable to selected APS proposed adjustments.

**Table KCH-1**

**Time Frame for Various APS-Proposed Adjustments**

| Adjustment | Time Frame for Valuation | Reference |
|---|---|---|
| Rate Base | New plant through 6/30/12. | La Benz, p. 18 |
| Employee count | March 2011 level. | La Benz, p. 23; JCL_WP23 |
| Wages | March 2011 level. | La Benz, p. 23; JCL_WP23 |
| Employee benefits | Actuarial valuation of 2011 benefits expense. | La Benz, p. 23; JCL_WP24 |
| Property taxes | Current (2011) rates on 12/31/10 values. | La Benz, p. 24 JCL_WP26 |
| Non-fuel O&M Expenses | Year ended 2010, adjusted for post-test year plant additions through 6/30/12. | Attachment JCL-8 |
| Fuel Expense | Expected calendar year 2012 fuel and purchased power prices, at adjusted test year consumption. | Ewen, p. 3, 10 |
| Retail sales | Year ended 12/31/10. | SFR, E-9 |

In my view, APS's blending of a Calendar Year 2010 test year with adjustments that are from disparate time periods results in a test period that is ill-defined and unsynchronized.

**Q. What do you mean by "unsynchronized" test period?**

A. A test period is considered to be fully synchronized when all elements used in ratemaking – i.e., rate base, revenues, and expenses – correspond to the very same time period, both with respect to the twelve-month period selected for measurement (e.g., Calendar Year 2010) as well as <u>when</u> during the selected period these values are being measured (i.e., end-of-period values versus average-of-period values). Conversely, a test period is considered to be unsynchronized when all elements used in ratemaking do *not* correspond to the same time period.

Q. **In general, is it preferable for test periods to be fully synchronized?**

A. Yes. A fully-synchronized test period adheres to what is known as the "matching principle." Measuring rate base, revenues, and expenses over the same twelve-month period and in the same manner (i.e., end-of-period or average-of-period) properly aligns these major ratemaking elements, ensuring the most reasonable basis for measuring whether the utility's rates provide it with a reasonable opportunity to earn its authorized rate of return. In contrast, an unsynchronized test period creates the potential for mismatches among ratemaking elements that distort the proper measurement of the utility's rate of return over the test period. I will provide an example of a problematic mismatch in APS's filing later in my testimony when I discuss the implications of bonus tax depreciation as it pertains to APS's proposed post-test year plant additions.

Q. **What is APS recommending with respect to post-test year adjustments?**

A. APS is proposing that several sets of post-test year adjustments be recognized for ratemaking purposes. In the aggregate, these post-test year adjustments add $432.2 million in total Company rate base[17] and $41.6 million in total Company expense[18] associated with facilities that are scheduled to come on line after December 31, 2010, but which are projected to be in service by June 30, 2012. The revenue requirement increase associated with the post-test year plant additions (in APS's Application) is $77.3 million.[19]

The Company's proposed post-test year adjustments fall into four categories: solar generation, fossil generation, nuclear generation, and distribution

[17] Source: APS Attachment JCL-7.
[18] Source: APS Attachment JCL-8.
[19] On page 4 of its Application, APS indicates that the revenue requirement impact is $48.9 million; however, APS notes that this figure excludes the solar generation plant additions.

and general and intangibles. Collectively, these plant additions appear to correspond to the full universe of plant additions that APS plans to bring into service between January 1, 2011 and June 30, 2012.

**Q. What is your assessment of APS's proposal for post-test period adjustments?**

A. In general, APS's proposal for post-test period additions is problematic in that it attempts to recover a return on (projected) new plant in service and associated depreciation expense that is not synchronized with the underlying test year. One conceptual problem with this unsynchronized approach is that the cost of new plant added through June 30, 2012 would be recovered in rates that are calculated based on the level of retail sales that existed at the end of 2010, rather than the sales that are projected for mid-2012, consistent with the proposed recovery of the cost of the new plant. In addition, there are other technical problems with APS's proposal that I will address in more detail a little later in my testimony.

On the other hand, I recognize that cost recovery for post-test period plant additions was included in the APS 2008 general rate case Settlement Agreement. I am also aware that APS has faced challenging financial circumstances in past years, including a downgrade to its credit rating by S&P in 2005 to BBB-. [20] Notably, S&P's downgrade was reversed back to BBB this past summer. Having been a participant in each of APS's major rate filings since 1999, I believe that recognition of post-test period plant additions in the prior rate case contributed to the improvement in APS's credit metrics.

[20] S&P's downgrade occurred on December 21, 2005. This was followed by a downgrade from Fitch on January 30, 2006.

The case for some recognition of post-test period plant additions is given additional support in light of the consideration that APS may not have the ability to pursue the more straightforward option of filing a rate case using a fully-projected (i.e., future) test period, an option that is available to many other utilities. R14-2-103 defines test year as "the one-year *historical* period used in determining rate base, operating income and rate of return." [Emphasis added] R14-2-103 goes on to state that "the end of the test year shall be the most recent practical date available prior to the filing." While I can offer no legal opinion on this language, one possible interpretation is that only historical test periods may be used to set rates in an APS rate case. For a utility that is adding substantial capital investment, limiting cost recovery to plant that is in service no later than December 31, 2010 – for a rate effective period starting in 2012 – creates predictable concerns about regulatory lag. The inclusion of post-test period plant is an obvious attempt to address this concern while maintaining the formality of an historical test period.

**Q. Given the preceding discussion, do you support APS's proposed post-test year plant additions adjustment as filed?**

A. No, I do not. I support some recognition of post-test year plant additions, but not as proposed by APS. I have three specific objections to APS's proposal, which I address through two adjustments. In addition, I have a separate objection and adjustment to a portion of the solar generation plant additions, which I address through a third adjustment later in my testimony.

**Q. Please proceed. What is your first basis for objecting to APS's proposal for a post-test year adjustment in the form requested by the Company?**

A. The first basis is that APS proposes to recognize its post-test period rate base adjustments as projected end-of-period values rather than average-of-period values.

**Q. What does it mean for rate base to be projected to an end-of-period value?**

A. It means that for the purpose of setting rates, APS is proposing to use its forecasted value of the rate base additions on the last day of the its proposed measurement period for the plant additions, June 30, 2012.

**Q. Please explain your disagreement with APS regarding the use of end-of-period rate base for the plant additions.**

A. The sole justification for using an end-of-period rate base is to address utility concerns about regulatory lag. According to the regulatory lag argument, utilities are challenged to earn their authorized rates of return on investment during periods of system expansion when historical test periods are used for setting rates. One means of reducing regulatory lag is to use a projected test period – or in this instance, an adjustment for projected plant additions – rather than a strictly historical measurement period. An entirely separate means of reducing regulatory lag is to adjust rate base in an historical test period to an end-of-period value, as this will cause the utility's authorized rate of return to be applied to the year-ending value of net plant in service. To this end, APS already uses end-of-period values for its Calendar Year 2010 test year (in addition to various adjustments that apply 2011 and 2012 values, as noted above).

However, in offering its plant additions adjustment, APS proposes to combine both a projected measurement period and an end-of-period rate base. This "doubling up" of attrition mitigation proposals is unorthodox and unreasonably aggressive. In my experience, jurisdictions seldom allow end-of-period values to be used for a projected (or forecasted) test period or measurement period. In a recent example, in its 2009 general rate case in Wyoming, PacifiCorp attempted to combine an end-of-period rate base with a projected test period. Although the revenue requirement for the case was resolved through stipulation, the Wyoming Commission expressly prohibited PacifiCorp from filing its next rate case using the combination of a future test period and an end of period rate base.

> In the event the Company makes a filing using a forecast test year, the Commission expects it to utilize an average rate base and not an end-of-period rate base. If the Company seeks to use an end-of-period rate base, it must include *in the application* a persuasive demonstration that its use would be appropriate. In addition, if the Company uses a forecast test year in its next application, it must [i] present the application using an average rate base and [ii] submit historical test year data, adjusted for known and measurable changes. In Paragraph 25 of the *Stipulation*, the Company has agreed to submit historical test year data with its next general rate case application for informational purposes.[21] [Italics in original.]

In short, an end-of-period rate base should only be contemplated when applied to an historical test period or measurement period. The proper measurement for a projected rate base is average-of-period value. Since the value of rate base changes each month as new plant is added and existing plant depreciates, determining rate base by averaging each month's value ensures that the asset base upon which the utility will earn a return is reflective of its "typical" value during the course of the test period or measurement period.

**Q. What is your recommended change to APS's post-test year plant additions to address this concern?**

[21] Wyoming Public Service Commission, Docket No. 20000-352-ER-09 (Record No. 12310), et al. Final Order at 33.

A. I recommend that the rate base used for APS's post-test year plant additions be modified to an average-of-period value over the post-test year measurement period, January 1, 2011 through June 30, 2012. The change is presented in Attachment KCH-2. This adjustment reduces the APS revenue requirement by approximately **$30.992** million.

**Q. What is your second basis for objecting to APS's proposed post-test year adjustment?**

A. Earlier in my testimony I discussed the problems of using an unsynchronized test period for ratemaking, and I cited the treatment of bonus tax depreciation as an example of a particularly problematic mismatch that complicates APS's proposed adjustment for post-test year plant additions. Properly recognized, bonus tax depreciation results in a reduction in rate base for ratemaking purposes. However, APS's post-test year adjustment wholly fails to recognize bonus tax depreciation.

**Q. What is bonus tax depreciation?**

A. Bonus tax depreciation refers to a greatly accelerated tax deduction for depreciation that has been permitted pursuant to several statutes signed into law in recent years to stimulate the economy. For example, bonus tax depreciation was permitted in 2008 and 2009 pursuant to the Economic Stimulus Act of 2008 and the American Recovery and Reinvestment Act of 2009. Generally, these acts permitted a first-year deprecation tax deduction equal to 50 percent of the cost of qualified property. According to the provisions of the American Recovery and Reinvestment Act of 2009, bonus tax depreciation was initially scheduled to end on December 31, 2009.

**Q. Was bonus tax depreciation been extended beyond 2009?**

A. Yes. Bonus tax depreciation was extended by the passage of two pieces of legislation in 2010. First, on September 27, 2010, the Small Business Jobs Act was signed into law. This act extended 50 percent bonus tax depreciation through December 31, 2010. Then, on December 17, 2010, the Tax Relief, Unemployment Insurance and Job Creation Act of 2010 was signed into law. This act increased bonus tax depreciation from 50 percent to 100 percent for qualified property acquired and placed into service on or after September 9, 2010 through December 31, 2011. In addition, 50 percent bonus tax depreciation was extended from January 1, 2012 through December 31, 2012.

**Q. How does bonus tax depreciation impact ratemaking for regulated utilities?**

A. Bonus tax depreciation is a form of accelerated tax depreciation, which is not a new phenomenon for regulators. Regulatory authorities have long contended with the fact that utility depreciation for tax purposes differs from utility book depreciation used in ratemaking. Generally, the tax benefits of accelerated depreciation are not passed through directly to ratepayers; indeed, there are restrictions on doing so applied by the Internal Revenue Service ("IRS"). Instead, the difference between the utility's tax expense calculated on a book basis (normalized tax expense) and its actual cash taxes payable (calculated on a tax basis) is recorded as accumulated deferred income tax ("ADIT"). ADIT represents tax expense accrued in the current period, but which is payable in a future period. According to the conventions of income tax normalization, the temporary cash benefit of a utility's ADIT is viewed as a source of zero-cost capital to the utility in the ratemaking process. Consequently, ADIT is booked as a credit against rate base, thereby reducing revenue requirements for customers.

Bonus tax depreciation affects rates through the same mechanics as standard accelerated depreciation – that is, it results in an increase in ADIT that is applied as a credit against rate base. Significantly, however, because bonus tax depreciation represents an extraordinary acceleration of depreciation for tax purposes, the impact of bonus tax depreciation on ADIT (and, consequently, on customer rates) is more dramatic than standard accelerated depreciation in the several years immediately following the placement of the qualifying plant into service.

**Q. What are the implications of bonus tax depreciation for this rate case?**

A. APS's filing includes the effects of bonus tax depreciation as applied to its Calendar Year 2010 test year rate base, but does not recognize any bonus tax depreciation for the plant additions projected to come on line between January 1, 2011 and June 30, 2012, even though these investments are eligible for bonus tax depreciation treatment. Consequently, the rate base additions being proposed by APS for the post-test year plant additions are materially overstated. By not reflecting bonus tax depreciation in its post-test year plant adjustment, APS is understating the amount of ADIT; by understating the amount of ADIT, APS is overstating rate base, and thus, overstating the revenue requirement associated with its post-test year plant additions.

**Q. Have you asked APS to explain why it has excluded the effects of bonus tax depreciation from its post-test year plant additions adjustment?**

A. Yes. According to APS's response to AECC 1.11.b:

> Consistent with the 2007 [sic] ACC Settlement, estimated projections of future unrealized deferred taxes related to post-Test Year plant additions (in this instance the period between January 1, 2011 and July 31, 2012) are not reflected in the Total Company and ACC Jurisdiction pro forma earned rate of returns. Inclusions of any such estimated projection of deferred taxes may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

**Q. What is your assessment of this explanation?**

A. There are several components to APS's explanation. The first sentence of APS's response indicates that the benefits of bonus tax depreciation were not passed on to customers in the post-test year adjustments included in the <u>prior</u> rate case. I concur. My response to this observation is that the 2009 Settlement[22] was a complex, negotiated package. The failure to recognize (or choice not to recognize ) the benefits of bonus tax depreciation associated with post-test year plant additions in a negotiated settlement does not imply that it is reasonable or proper to ignore this benefit to customers as part of a litigated proceeding.

The second and third sentences suggest that recognizing bonus tax depreciation as part of the post-test year additions might run afoul of IRS regulations. The background to APS's argument is that the Internal Revenue Code §168 requires that in determining rates using a cost-of-service methodology, utilities must use the normalization method (as I described above) to calculate Federal income tax expense. Utilities that fail to use the normalization method may lose the option of using accelerated depreciation for tax purposes. This, presumably, is the "unfavorable tax consequence" referenced by APS.

[22] APS's Response to AECC 1.11.b mistakenly refers to the "2007" ACC Settlement. The Settlement Agreement in the prior general rate case, which incorporated certain post-test year adjustments, was submitted to the Commission on June 12, 2009.

At issue is whether the IRS would determine that recognition of bonus tax depreciation applicable to APS's post-test year plant is a normalization violation. In responding to this concern, I note that as a threshold matter, any recognition of bonus tax depreciation applied to post-test period plant additions can (and ought to) be implemented by means of booking the requisite amount of additional ADIT – an approach that is entirely consistent with the normalization method. I believe the concerns expressed by APS stem not so much from whether the implementation mechanics of recognizing bonus tax depreciation would ignore normalization principles, but rather the risk that the IRS would deem the recognition of bonus tax deprecation to be a normalization violation solely because it was calculated using *an unsynchronized test period.* As discussed by APS in its response to Staff 19.14.a:

> [IRS regulations require] that the reduction in rate base [through ADIT] be synchronized with the quantity of deferred taxes reflected in cost of service. The Company is concerned that the incremental ADIT associated with post-test period plant fails to satisfy this requirement insofar as it was never included in cost of service.

In other words, the concern is not that recognizing bonus tax depreciation would be inconsistent with the *principles* of income tax normalization, but that such recognition might be construed by the IRS to be a technical violation of its regulations because the incremental ADIT would be applied to an unsynchronized test period. Although the potential for this type of adverse ruling is identified by APS as a risk, the Company has not cited any specific rulings by the IRS on the treatment of bonus tax depreciation in circumstances comparable to this general rate case that affirm this interpretation.[23]

The irony of this situation should be readily apparent. APS proposes an unsynchronized, post-test year adjustment to rate base in order to boost its revenues and mitigate regulatory lag. Ordinarily, the introduction of new plant in service would be accompanied by recognition of bonus tax depreciation in the form of additional ADIT, which in turn would be an offset to rate base – mitigating the impact of the new plant on customer rates. But not in APS's proposal. Because APS's treatment of post-test period plant is unsynchronized with its historical test period, there is an apparent risk that the IRS would deem recognition of incremental ADIT to be a normalization violation, resulting in unfavorable tax consequences. Therefore (according to APS), customers should forego the benefits of incremental ADIT, and rates should be set as if bonus depreciation does not apply to the plant additions – even though it does. The upshot of this reasoning is that APS gets to charge higher rates than would otherwise be the case. From a ratemaking perspective, this outcome is wholly unsatisfactory.

**Q. Has APS provided information that allows you to estimate the revenue requirement impact of recognizing bonus tax depreciation associated with its post-test year plant additions adjustment?**

A. Yes. Based on information provided by APS in response to AECC Data Request 1.11.c, I estimate that recognizing bonus depreciation in the post-test year

[23] In APS's Response to Staff 19.14.a, APS provides an explanation of the theory supporting its assertion of risk, but identifies no specific findings by the IRS for the specific circumstances at issue in this case.

plant additions would reduce the APS revenue requirement in the approximate range of $8 million to $13 million.

Q. **What ratemaking treatment are you recommending for bonus tax depreciation applicable to post-test year plant additions?**

A. The prospect of awarding APS an increase in rates attributable, in part, to post-test year plant additions, but which does not recognize bonus tax depreciation is extremely unpalatable. However, rather than risk the potential IRS sanction, I recommend that the Commission consider this issue in the context of my recommendation, discussed on pages 12-15 of this testimony, to use an average-of-period value for measuring the post-test period rate base additions. That is, even though my argument to use average-of-period stands on its own merit, this argument should be given even greater weight in light of the bonus tax depreciation considerations discussed here. Recognizing the plant additions as an average-of-period value, while foregoing the bonus tax depreciation benefit to avoid the IRS sanction risk, represents a middle ground position that is more than fair to APS. On the other hand, if bonus tax depreciation is not recognized, it would be particularly egregious for APS to be awarded recovery of post-test year plant additions measured at end-of-period values.

Q. **What is your third basis for objecting to APS's proposed post-test year adjustment?**

A. As I stated on page 11 of this direct testimony, one of the conceptual problems with APS's unsynchronized approach is that the cost of new plant added through June 30, 2012 would be recovered in rates that are calculated based on the level of retail sales that existed at the end of 2010, rather than the sales that are projected for mid-2012, consistent with the proposed recovery of the cost of the new plant. In my view, this mismatch is entirely inappropriate. One of the major reasons for installing new plant in the first place is to serve new load and projected new load over the long term. Including the costs of new facilities through the middle of 2012, but not recognizing the projected new load over that same time period, is unreasonable.

**Q. What is your recommendation to the Commission on this issue?**

A. I recommend that the Commission approve an adjustment to APS's retail load that corresponds to the time period being used to reflect plant additions. As I am recommending an average-of-period plant additions adjustment which has the midpoint of September 30, 2011, I recommend using the twelve-month load forecast with the same midpoint for the level of retail sales (April 1, 2011 through March 31, 2012). I am using a load forecast prepared by APS for this period.

After accounting for increased fuel expense associated with load growth, this adjustment results in a decrease of **$23.887** million to APS's revenue requirement. This calculation is presented in Attachment KCH-3.

**Q. Does the load forecast you are recommending for setting APS's rates take into account projected savings from APS's energy efficiency programs?**

A. Yes. I am using an APS load forecast that is inclusive of savings from DSM and energy efficiency.

*Transfer of Renewable Energy Costs into Base Rates*

**Q. What is APS proposing with respect to the transfer of renewable energy costs into base rates?**

A. A portion of the post-test year plant additions that APS is proposing to include in base rates is associated with three of APS's renewable energy programs: AZ Sun, the Schools and Government Program ("S&G Program"), and the Community Power Project – Flagstaff Program ("CPP"). As described in the direct testimony of APS witness Jeffrey B. Guldner, costs for these programs are currently recovered through the Renewable Energy Surcharge ("RES").

APS's post-test year plant additions adjustment, as filed, includes three AZ Sun projects, totaling 50 MW, that are projected to be in service by June 30, 2012. As provided in Decision No. 71502, the first 50 MW of AZ Sun is being recovered through the RES Tariff until the investment is included in base rates or another recovery mechanism, as determined in this rate case.

The S&G program is expected to deploy 8 MW of APS-owned assets by June 30, 2012 and the CPP will add another 1.5 MW by December 2011.

**Q. What is the impact on base rates of APS's proposed adjustment?**

A. APS's proposed adjustment (as filed) would increase total Company rate base by $267,633,000 and operating expense by $12,385,000. The associated revenue requirement increase in jurisdictional base rates is $44.9 million. This increase in base rates would displace recovery through the RES Tariff. As part of the APS-identified adjustments discussed previously in my testimony, the revenue requirement of the solar generation plant additions was reduced by $2.9 million to $42.0 million.

**Q. Do you have any objections to APS's proposal for inclusion of post-test year solar generation costs that are in addition to the objections you have presented above concerning the post-test year plant additions as a whole?**

A. Yes. As a distinct matter, APS's proposal for post-test year solar generation costs includes costs that exceed the Market Cost of Comparable Conventional Generation, as this term is defined in R14-2-1801.K. According to this provision of the RES Rule:

> "Market Cost of Comparable Conventional Generation" means the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal, and long-term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs.

The RES tariff is expressly intended to recover the costs of qualifying resources in excess of the Market Cost of Comparable Conventional Generation. R14-2-1808.B.4 provides that the utility's RES tariff filing shall provide "data to demonstrate that the Affected Utility's proposed Tariff is designed to recover only the costs in excess of the Market Cost of Comparable Conventional Generation." As the RES tariff and the accompanying RES Adjustor rate have been created for the very purpose of recovering these above-market costs, it is, in my view, unreasonable to shift the cost recovery for above-market costs into base rates. Rather, base rates should only be used for recovery of renewable generation undertaken to comply with the RES tariff <u>up to</u> the amount of the Market Cost of Comparable Conventional Generation.

**Q. The solar generation costs that APS is seeking to include in the post-test year plant adjustment is utility-owned. Does the RES Rule make any distinctions between utility-owned renewable generation and third-party-owned**

**renewable generation (that may be purchased by utilities) with respect to the treatment of above-market costs?**

A. No. The purpose of the RES Adjustor is to recover costs that are in excess of the Market Cost of Comparable Conventional Generation. There is absolutely no distinction in the Rule between utility-owned generation and generation that is purchased from third parties. Indeed, there is no logical or equitable reason to make such a distinction. Above-market cost is above-market cost: it matters not whether it derives from a utility-owned facility or a utility purchase from a third party.

**Q. Why is it important for above-market renewable energy costs to continue to be recovered in the RES Adjustor rather than base rates?**

A. It is a matter of transparency in public policy. The RES requirement is a mandate and the RES Adjustor clearly identifies the above-market component of the cost of this mandate. If above-market costs are shifted to base rates it would obscure the true costs of the RES requirement to the public, making these costs appear to be less than they actually are. This would not be good public policy. Moreover, the structure of cost recovery in the RES Tariff differs from that of base rates; notably, each customer class has a per-meter cap applicable to the RES Adjustor that limits the exposure of any individual customer to the above-market costs of the program. Shifting above-market costs into base rates undermines the protection otherwise afforded by the RES Adjustor caps.

**Q. What is your recommendation to the Commission regarding the proper amount of post-test year solar generation costs that should be recovered in base rates?**

A. I recommend that all costs in excess of the Market Cost of Comparable Conventional Generation be excluded from base rates. Prudently-incurred costs in excess of the Market Cost of Comparable Conventional Generation should remain subject to the RES Tariff and recovered through the RES Adjustor.

I present this adjustment in Attachment KCH-4. This adjustment reduces APS's proposed revenue requirement increase by **$9.928** million. Note that this adjustment is applied to the average-of-period value that I derived in my prior adjustment to post-test year plant additions. If my market cost adjustment were to be applied to the end-of-period value utilized by APS, the adjustment would be greater.

**Q. In calculating the market cost adjustment, what portion of APS's solar generation revenue requirement did you determine to be in excess of the Market Cost of Comparable Conventional Generation?**

A. Using APS's assumptions about the Market Cost of Comparable Conventional Generation for 2012, I determined that 64 percent of APS's solar generation revenue requirement is in excess of that level and should be excluded from base rates. This analysis is presented in Confidential Attachment KCH-4, page 4.

**Q. What general representations has APS made with respect to the portion of its solar generation costs that it considers to be above the Market Cost of Comparable Conventional Generation?**

A. In APS's Response to AECC 4.1.2(a), the Company indicates that on average, costs in excess of the market costs of generation for its AZ Sun plants represent 30 percent of project costs analyzed.

**Q. Based on this response, we didn't you include 70 percent of APS's solar generation revenue requirement in base rates?**

A. In reviewing the workpapers supporting APS's calculation, I determined that that 30 percent "above-market" calculation is based on comparing the long-term levelized cost of the solar plant additions to APS's projection of the long-term levelized Market Cost of Comparable Conventional Generation. While I have no objection to using the long-term levelized cost of the solar plant additions as the basis of the solar generation costs (doing so is more favorable to APS than using the current-year revenue requirement), I do not believe it is appropriate, for the purpose of determining the portion of costs included in test year base rates, to use a long-term levelized projection to represent the Market Cost of Comparable Conventional Generation.

**Q. Why not?**

A. The benchmark that delineates what <u>today's</u> customers pay in base rates should be <u>today's</u> Market Cost of Comparable Conventional Generation – not a blended value that is based on a projection of market costs over the next thirty-five years.

Needless to say, a projection of the Market Cost of Comparable Conventional Generation over a long-term requires assumptions about energy price and capacity cost escalation that is little more than speculation. But even if the future Market Cost of Comparable Conventional Generation was known with perfect certainty, today's base rates should be determined using current-day values. Customers should not pay rates based on thirty-five year projections of market prices.

**Q. In offering your adjustment to base rates, are you recommending that APS cost recovery for the solar plant additions be denied?**

A. No. I am simply making a recommendation regarding the appropriate recovery in base rates. To the extent that the cost in excess of the Market Cost of Comparable Conventional Generation is prudently-incurred, it should be eligible for recovery through the RES Adjustor.

## SYSTEM BENEFITS CHARGE - NUCLEAR DECOMMISSIONING COSTS

**Q. What is APS recommending with respect to the recovery of nuclear decommissioning costs?**

A. APS has been granted approval by the Nuclear Regulatory Commission to extend the life of the Palo Verde Nuclear Generating Station ("PVNGS") by twenty years. This life extension through the 2045-47 time frame causes two fundamental impacts on the funds that must be accrued for the purpose of nuclear decommissioning: (1) it increases the total amount of money projected to be required to complete the decommissioning, due, in large part, to the expectation that decommissioning costs will be more expensive in the future because of inflation; and (2) it extends the time for contributions to be made to the sinking fund required to pay for the decommissioning, and similarly, extends the time that interest can be earned on the balance in the sinking fund. The net effect of these two impacts is that the annual contribution to the sinking fund necessary to pay for the decommissioning *decreases* significantly when the life of the facility is extended.

APS customers pay for decommissioning costs through the Systems Benefits Charge ("SBC"). According to Paragraph 11.4 of the 2009 Settlement Agreement, APS is required to seek to reduce its SBC by January 1, 2012 to reflect the reduced decommissioning costs attributable to the PVNGS life extension. The relevant language states:

> ...Pursuant to the terms of this Settlement, if and when license extension is granted, APS shall file with the Commission a revised nuclear decommissioning funding requirement and a commensurate downward adjustment to the decommissioning component of the Company's SBC and a reduction to the PSA as discussed above to be effective upon the later of the grant of license extension or January 1, 2012...

Largely consistent with this provision, on June 17, 2011, in Docket No. E-01345A-11-0247, APS filed an Application with the Commission to reduce the SBC by approximately $7.2 million per year, effective February 1, 2012. In addition, in this docket, APS has proposed a number of adjustments to the SBC that are unrelated to the PVGNS life extension. These APS adjustments are summarized on Attachment KCH-5, page 1, lines 8-11.

**Q. Do you agree that $7.2 million is the appropriate reduction in the SBC associated with PVGNS life extension?**

A. No. I believe the SBC should be reduced by an <u>additional</u> $8.704 million per year to better reflect the reduction in decommissioning costs associated with the PVNGS life extension.

**Q. Please explain.**

A. As shown in Attachment KCH-5, page 1, lines 9-10, APS's proposed $7.2 million reduction in the SBC that is related to PVNGS expenses is comprised of two components: a reduction in ISFSI expense of $4.236 million and a reduction in PVNGS decommissioning expense of $2.947 million. These two adjustments sum to $7.183 million.[24]

According to APS witness Jason C. La Benz, the going-forward annual decommissioning expense for all three PVNGS units – taking account of the life extension – is $17.249 million per year.[25] The ACC jurisdictional portion of this is $16.830 million. However, according to APS's workpapers, *prior to life extension*, the pro forma annual decommissioning expense for 2011 is just $15.630 million (jurisdictional).[26] The implication here is that the nuclear decommissioning costs that APS is seeking to recover from customers *post*-life extension appears to be greater than it would have been *absent* life extension.

The answer to this seeming paradox is revealed when we examine the PVNGS decommissioning costs that APS is seeking to recover from customers on a unit by unit basis.

In the case of PVNGS 1, because of the life extension, the annual nuclear decommissioning trust fund expense is reduced from $4.558 million to $0.449 million (total Company).[27] This reduction makes sense, in that it is consistent with my observation above that the annual contribution to the sinking fund necessary to pay for the decommissioning decreases significantly when the life of the facility is extended.

---

[24] See also direct testimony of Jason C. La Benz, p. 22, line 17. Note that ISFSI stands for "independent spent fuel storage installation."
[25] Ibid., p. 22, line 16.
[26] Source: JCL WP 22, p. 4.
[27] Source: Ibid.

For PVNGS 3, the annual nuclear decommissioning trust fund expense is reduced from $5.414 million to $1.832 million (total Company) due to life extension.[28] This reduction also makes sense.

However, in the case of PVNGS Unit 2, APS is actually recommending a significant *increase* in the annual decommissioning expense: from $6.047 million (pre-life-extension) to $14.968 million (post-life-extension, total Company).[29] The reason for this counter-intuitive jump in decommissioning expense for PVNGS Unit 2 involves the terms of a sale/leaseback transaction that APS entered for that unit, which, according to APS, *requires all decommissioning costs to be paid in full by 2015.* In other words, according to the terms of the sale/leaseback agreement, the incremental projected decommissioning cost associated with the life extension – needed to address costs starting in 2045 – must be fully funded by 2015. So rather than experiencing a *reduction* in annual decommissioning expense comparable to that of PVNGS 1 and 3, the annual nuclear decommissioning expense for PVNGS 2 actually increases by $8.9 million. The jurisdictional share of this increase is $8.7 million.

In my opinion, it is not reasonable for today's APS customers to bear this level of decommissioning expense for PVNGS 2. The life extension will provide benefits to customers for another thirty years beyond 2015. The decommissioning costs paid by APS customers should correspond to the remaining life of the unit.

**Q. What is your recommendation to the Commission?**

[28] Source: Ibid.
[29] Source: Ibid.

A. Although a reasonable case can be made to reduce the annual decommissioning expense charged to APS customers for PVNGS 2 to levels comparable to PVNGS 1 and 3, I am recommending that the decommissioning expense charged to customers for PVNGS 2 merely be rolled back to the pre-life-extension annual expense of $6.047 million (total Company). Such an adjustment, although it would not pass on any decommissioning benefits associated with the life extension of PVNGS 2 at this time, would at least hold today's customers harmless from it. This level of expense in rates should remain in place until the 2015 expiration of the sale/leaseback terms, at which time it should be reset to assure full recovery from customers of the remaining decommissioning obligation, plus reimbursement of any funding provided by APS between 2012 and 2015 to cover the gap between the funds provided by customers and the decommissioning funding requirements of the sale/leaseback transaction.

This adjustment reduces the SBC charge by **$8.704** million, which is the jurisdictional share of the difference between the $6.047 million pre-life-extension decommissioning expense for PVNGS 2 and the $14.968 million post-life-extension expense. This adjustment is shown in Attachment KCH-5, page 1, line 14. The impact on the SBC unit cost is shown in Attachment KCH-5, page 2.

**PROPOSED CHANGES TO THE 90/10 SHARING PROVISION IN THE PSA**

**Q. What is the 90/10 sharing provision in the PSA?**

A. APS's Base Fuel Rate is established in a general rate case. The PSA is a mechanism by which deviations from the Base Fuel Rate are either recovered from or credited to customers in between rate cases. For most PSA items, 90 percent of the recovery or credit is allocated to customers and 10 percent is allocated to APS. The 90/10 sharing provision has been part of the PSA since the PSA was adopted in 2005. The adoption of the PSA was pursuant to a Settlement Agreement (to which AECC was a party) that was approved, with modifications, by the Commission in Decision No. 67744.

**Q. What is APS's proposal with respect to the 90/10 sharing provision in the PSA?**

A. As discussed in the direct testimony of APS witness Peter M. Ewen, APS is proposing to eliminate the 90/10 sharing provision. This change would place 100 percent of the risk from deviations in power supply costs on customers.

**Q. What is APS's justification for this proposed change?**

A. Mr. Ewen cites to three principal reasons: (1) APS is the only Arizona utility to have a 90/10 sharing mechanism; (2) fuel and purchased power prices are outside APS's control, and therefore, the 10 percent utility sharing acts only as a penalty or windfall; and (3) eliminating the 90/10 sharing provision will facilitate the resetting of fuel rates without controversy.

**Q. Do you agree with APS's proposal?**

A. No, I do not. In my opinion, eliminating the sharing provision would be a mistake. It is essential to keep customer and Company interests aligned by retaining an equitable sharing mechanism between customers and APS in the PSA.

APS's proposal fails to properly align customer and Company interests or to equitably share risks. Instead, under the Company's proposal, the PSA would simply pass through 100 percent of changes in Base Fuel Rates in between rate cases to customers. This type of 100 percent cost pass-through seriously reduces APS's incentive to manage its fuel and purchased power costs as well as it would manage them if the Company remained exposed to the energy cost risk. It is axiomatic that when a firm stands to gain or lose from its cost management decisions, as APS does today, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs. I strongly recommend against adoption of a PSA design that removes this natural economic incentive.

**Q. But aren't energy costs largely outside a utility's control?**

A. Absolutely not. The utility's energy costs are completely out of the customers' control, but not of the utility. Utilities are not mere passive bystanders when it comes to managing power costs. Every hour of every day, utilities need to be managing the dispatch of their systems to achieve minimum costs, subject to the reliability constraints under which they operate. This requires a sophisticated approach to managing utility-owned resources, as well as conducting a large volume of transactions – purchases and sales – throughout the year. The depth and breadth of this around-the-clock dispatch and balancing requirement is so extensive that it is inadvisable for regulators to rely solely on after-the-fact prudence audits to ensure sound utility cost-management performance; rather it is far preferable for the Commission to harness the natural economic self-interest of the company to incentivize the desired behavior of ensuring sound utility cost-management performance.

**Q. Are there other aspects of managing fuel and purchased power costs that are important besides optimizing system dispatch?**

A. Yes. In addition to hourly dispatch, APS enters into numerous transactions throughout the course of the year that impact its fuel and purchased power costs, such as short- and long-term purchases and sales and fuel procurement. For example, APS transacted for more than 6.8 billion kilowatt-hours of long-term, intermediate-term, and short-term power purchases in 2010, valued at over $317 million, consummated with more than 90 counterparties. The Company also made over 4.1 billion kilowatt-hours of long-term, intermediate term, and short-term sales in 2010, worth more than $210 million, also transacted with more than 90 counterparties.[30] It is critical that APS have the proper incentives for these transactions to produce the greatest possible net benefit to customers. This incentive is most efficiently implemented by a regime in which APS shares in the benefits and risks of its decisions.

In addition to creating the proper incentives for APS's interactions with other parties, incentives play an important role with respect to the Company's own operations. For example, it is important for APS to schedule plant maintenance in a manner that takes into account the impact on fuel costs, e.g., by avoiding outages when replacement power is likely to be most expensive. Under the current PSA, the benefits and costs of deviations from the Base Fuel Rate are partially absorbed by APS; thus, currently, the Company has the incentive to take proper account of fuel costs when scheduling outages. However, a regime in which 100 percent of Base Fuel Rate deviations are passed through to customers removes the Company's natural economic incentive to properly consider the impact on fuel costs in its operations.

[30] Source: APS FERC Form 1, pp. 310-11; 326-27.

**Q. Does APS hedge a portion of its fuel and purchased power costs?**

A. Yes. When a utility hedges its fuel and/or purchased power costs, it is effectively locking in the cost of fuel and/or purchased power that is expected to be consumed in the future. According to information filed by APS in Docket No. E-01345A-09, APS hedges its fuel and purchased power cost on a rolling three-year forward basis. Approximately 85 percent of APS's price risk is hedged in year one; 50 to 60 percent is hedged in year two; and 30 to 40 percent is hedged in year three. To execute these hedges, APS uses a combination of exchange-traded futures and financial over-the-counter market products.

So while APS may be able to argue that it does not control the market price of natural gas, it is nevertheless the case that the Company's *decisions* in executing its natural gas hedging strategy (e.g., timing, magnitude) have a large influence on the cost of gas that APS ultimately incurs and the fuel costs that are passed on to customers.

**Q. If APS locks in forward fuel prices at prices that later decline, how are these costs treated for ratemaking purposes?**

A. In a general rate case, if the hedged price exceeds the projected market price, the difference is included as a component of fuel cost for full recovery from customers, subject only to prudency considerations. Conversely, if the hedged price is below the projected market price, this difference is credited against the fuel cost recovered from customers.

In between rate cases, these differences are included in the PSA, subject to the 90/10 sharing.

**Q. What natural gas hedging costs are included for recovery in this general rate case?**

A. In this case, APS is seeking to recover approximately $70 million in gas hedge liquidation costs; that is, APS's hedges cost $70 million more than the projected cost of natural gas in 2012. This $70 million cost constitutes approximately 25 percent of APS's projected $273 million of natural gas costs in this case.

**Q. How would APS's proposal to eliminate the 90/10 sharing affect the sharing of risks related to APS's hedging decisions?**

A. Under the current PSA, if APS's hedges turn out to cost more than was projected at the time of the general rate case, the Company shares in this cost; similarly, if the Company's hedging decisions prove to reduce fuel costs below what was projected in the general rate case, APS shares in this gain.

Under APS's proposal to eliminate the sharing mechanism, there would be no risk whatsoever to APS from its hedging decisions: short of a prudency disallowance, 100 percent of the risk from APS's hedging decisions would be borne by customers.

**Q. Do you believe that the threat of a prudency disallowance is sufficient incentive to fully align utility and customer interests in managing fuel costs in between rate cases?**

A. No. In my view, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for a utility having "skin in the game" when it comes to managing its fuel costs. A finding of imprudence essentially requires a determination that a utility acted unreasonably in its power cost management.

In contrast, a risk-sharing mechanism structured such that each and every transaction affects the Company's bottom line, provides an incentive for the Company to get the *best possible deal* from every transaction. Striving to get the best possible deal from every transaction is different from simply not behaving unreasonably. Getting the best possible deal is a more exacting and efficient aspiration. A well-crafted sharing mechanism supports this objective.

Q. **In the past year, have other utility commissions in the Western United States considered the question of requiring a sharing mechanism in a power supply adjustor mechanism?**

A. Yes. In the past year, both the Wyoming and Utah commissions considered whether to adopt a sharing mechanism for a power cost adjustor mechanism.

Q. **Are you personally familiar with these two cases?**

A. Yes. I was a witness in both cases.

Q. **What determinations did the Wyoming and Utah commissions reach?**

A. The Wyoming and Utah commissions each independently determined to adopt 70/30 sharing mechanisms, with 70 percent of the deviations in base fuel costs being assigned to customers and 30 percent assigned to the utility.[31]

Q. **In your opinion, does the 70/30 sharing arrangements adopted by the Wyoming and Utah commissions strike a reasonable balance between utility and customer interests?**

[31] Wyoming Public Service Commission Memorandum Opinion, Findings and Order, February 4, 2011, issued in Docket No. 20000-368-EA-10.
Utah Public Service Commission, Corrected Report and Order, March 3, 2011, issued in Docket No. 09-035-15.

A. Yes, it does. This sharing ratio places the substantial majority of responsibility for recovering base fuel cost deviations on customers, but it meaningfully aligns utility and customer interests through shared benefits and costs.

**Q. Should this Commission consider adopting the 70/30 sharing provision recently adopted in Wyoming and Utah?**

A. Yes. If the Commission is interested in revisiting the question of the appropriate sharing proportions in the PSA, then I strongly encourage the Commission to consider adopting the 70/30 sharing proportion that was recently approved in these other two Western states, rather than the 100/0 approach advocated by APS, which is a movement in the entirely wrong direction.

**Q. What is your response to Mr. Ewen's observation that APS is the only Arizona utility to have a 90/10 sharing mechanism?**

A. It is correct that TEP has a PSA-type adjustor mechanism (Purchased Power and Fuel Adjustment Clause or "PPFAC") that assigns 100 percent of base fuel cost deviations to customers. However, the facts surrounding the adoption of this mechanism for TEP are very different from those of APS. The TEP PPFAC was adopted as part of a comprehensive settlement agreement in 2008 following the expiration of the TEP rate freeze that had been in effect since a prior 1999 Settlement Agreement. As such, the structure of the TEP PPFAC that was negotiated was but one piece of a large and interrelated package.

**Q. Where you directly involved in the negotiation of the 2008 TEP Settlement Agreement?**

A. Yes, I was.

**Q. What facts surrounding the adoption of the TEP PPFAC as part of a comprehensive settlement agreement are particularly noteworthy?**

A. At least two facts are particularly noteworthy that distinguish TEP's situation from APS's situation. First, the 2008 TEP Settlement Agreement that adopted the PPFAC without a sharing provision also adopted a <u>four-year freeze</u> in base rates. This base rate freeze was all the more noteworthy in that it followed a prior freeze in TEP's rates that had extended over nine years, spanning 1999 to 2008, that had resulted from a previous settlement agreement in 1999. The long-term base rate stability that was achieved as part of the 2008 TEP Settlement Agreement was an important factor in justifying the absence of a sharing mechanism in the PPFAC for the same time period.

Second, the order approving the 2008 Settlement Agreement also determined that millions of dollars of stranded cost overpayments by customers would be applied (with interest) as a credit to the initial PPFAC account. This amount was later determined to be $58.8 million.[32] In other words, by design, the first $58.8 million-plus of fuel costs that would otherwise have flowed through the TEP PPFAC was intended to be completely offset by this stranded cost credit. Consequently, even though the TEP PPFAC has been on the books since 2009 – the actual PPFAC charge to customers has yet to be anything but zero. This is a decidedly different set of circumstances than has been experienced with APS's PSA. The lack of a sharing mechanism in the TEP PPFAC should not be used as a precedent for eliminating this important provision in the APS PSA. The circumstances are not comparable.

[32] Decision No. 70958 at 2.

## REVENUE DECOUPLING

**Q. What is APS proposing with respect to revenue decoupling?**

A. As described in the direct testimony of APS witness Leland Snook, APS is proposing to adopt a full revenue decoupling mechanism, as part of what APS terms its Energy and Infrastructure Account Adjustment ("EIA").

The EIA would apply to almost all metered retail customers, including the largest industrial customers. It would be designed to recover any differences between allowed non-fuel revenue-per-customer and actual non-fuel revenue-per-customer. The EIA charge (or credit) would be recovered through a percentage adjustor applied to all applicable rate schedules.

**Q. Are you familiar with the Commission Policy Statements regarding decoupling that were issued December 29, 2010?**

A. Yes, I am.

**Q. Did AECC participate in the decoupling workshop process that was sponsored by the Commission in 2010?**

A. Yes.

**Q. What position regarding revenue decoupling did AECC advocate as part of the workshops?**

A. AECC consistently recommended <u>against</u> adoption of a decoupling mechanism for <u>any customer class</u>. At the most fundamental level, decoupling is as much a "revenue assurance" mechanism as it is a "conservation enabling" mechanism. As such, it is sure to capture a much wider range of effects than just customer responses to utility-sponsored energy efficiency programs. For example, decoupling provides unwarranted insulation to the utility from the effects of price elasticity. Generally, all sellers of goods face a risk that price increases will reduce sales. But, with decoupling, if customers respond to utility rate hikes by reducing their electricity, fixed charges are increased to compensate the utility for any resultant reduction in per-customer usage. Such an increase reflects an undue transfer of risk from utilities to customers.

Further, to the extent that customers reduce usage in response to economic conditions or otherwise practice self-funded energy conservation, these behaviors will be captured in the decoupling adjustment and unduly increase rates to customers. In addition, decoupling as proposed by APS will also cause rates to be adjusted due to changes in weather-related usage.

Q. **Do the Commission Policy Statements provide for any flexibility with respect to the treatment of customer classes?**

A. Yes. Policy Statement 11 provides that:

> Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes. Utilities should address any proposed distinct treatments and justify why certain customer classes may merit different treatment.

Q. **If decoupling is approved by the Commission for APS in this proceeding, are there customer classes that merit different treatment?**

A. Yes. At a minimum, Rate Schedules 34 and 35 should be excluded from the EIA. Recall that the premise for decoupling is to insulate the utility from the loss of fixed-cost recovery when customers conserve energy by participating in utility-sponsored energy efficiency programs. This erosion of fixed-cost recovery may occur because, for many rate schedules, a portion of fixed cost is recovered through the volumetric energy charge. Thus, if energy consumption declines, all other things being equal, fixed cost recovery from conserving customers on these rate schedules declines.

However, this is not the case for Rate Schedules 34 and 35, which serve customers with billing demands of 3 MW or above. For these customers, a very large portion of the cost recovery occurs through a demand charge; very little – if any – fixed cost recovery occurs through the volumetric energy charge. In other words, the rate designs of these customer classes already insulate APS from the loss of fixed-cost recovery when these customers conserve energy.

For example, in the case of Rate Schedule 34, the proposed energy charge is 4.258 cents per kWh. If a Schedule 34 customer conserves energy, it will allow APS to reduce its most expensive dispatchable generation, which is typically natural gas. According to APS's filing in this case, the average fuel cost of its gas generation is 6.15 cents per kWh[33] – well above the Schedule 34 energy charge. In light of this price/cost relationship, it is clear that decoupling is not necessary to ensure that APS continues to recover its fixed cost from a Schedule 34 customer when a Schedule 34 customer conserves energy.

Rate Schedule 35 is a time-of-use rate for which the proposed energy charges range from 3.559 cents per kWh (off-peak) to 4.749 cents per kWh (on-peak). Thus, the same conclusion holds true: decoupling is not necessary to ensure that APS continues to recover its fixed cost from a Schedule 35 customer when a Schedule 35 customer conserves energy.

**Q. Wouldn't energy conservation also enable a Schedule 34 or 35 customer to reduce its demand charge?**

[33] APS Attachment PME-3, page 2 (Updated by APS Using 9/3/0/11 Prices)

A. It is much more difficult for a Schedule 34 or 35 customer to reduce its demand charge from conservation in the short term given the structure of APS's tariff. This is because the demand charges for Rate Schedules 34 and 35 are subject to an 80% ratchet. In APS's tariff, this ratchet means that the demand charge in any given month cannot fall below 80% of its peak level measured during the preceding six summer months. The upshot is that energy conservation for a Schedule 34 or 35 customer is much less likely to influence its demand-related charges than its energy-related charges. And as I have discussed, there is little or no fixed cost recovery in the Schedule 34 and 35 energy charges at the margin.

**Q. In his direct testimony, APS witness Snook suggested that Schedule 34 and 35 customers might merit a ratemaking alternative to decoupling. Do you wish to respond?**

A. Yes. Mr. Snook's testimony largely acknowledges the points I am making regarding Schedule 34 and 35 rate design. However, he indicates that to provide the insulation that APS is seeking, the demand ratchet for these customers might need to be increased up to 100 percent and/or the ratchet period extended from twelve to twenty-four months.

I disagree. A ratchet of 100 percent on generation demand charges is extreme. I am aware of no other utility in America with such a ratchet on generation demand. Indeed, a ratchet of 80 percent on generation demand is already extraordinarily high – and I am certain is among the highest in the country. The existing rate design for Rates 34 and 35 already insulates APS from erosion of fixed cost recovery attributable to energy conservation. There is no need to make the rate design more extreme just to satisfy APS's desire for revenue assurance.

**Q. Are there other reasons for exempting certain customer classes from decoupling if decoupling is otherwise adopted?**

A. Yes. Maintaining a constant "revenue per customer" or "fixed-cost recovery per customer" is not an appropriate rate design objective for classes of customers that have few customers, have heterogeneous populations, and/or whose class composition shows a wide range of usage levels, such as Rates 34/35 and the largest Rate 32 customers. The fixed-cost recovery per customer of these classes will be very sensitive to the *composition* of these customers; for example, the opening or closing of a copper mine would impact such a calculation without at all being representative of utility-sponsored conservation programs. In short, given the tremendous diversity among non-residential customers, attempting to attribute to utility-sponsored energy conservation projects changes in "average fixed-cost recovery per customer" of non-residential customers is meaningless. The concept of an "average" non-residential customer for this purpose is without merit as a ratemaking mechanism.

Changes in the overall economy are far more likely to influence fixed-cost recovery per customer for non-residential customers than energy conservation programs. Application of decoupling to these customers would result in undue changes in rates in response to factors that are unrelated to energy conservation. This would be particularly unfortunate since the primary objectives of decoupling can be accomplished for these customers through rate design, as discussed above.

**Q. Is revenue decoupling commonplace among electric utilities in the Western United States?**

A. No. Outside of California, I am not aware of electric decoupling regimes in place anywhere in the West except in the Portland General Electric and Idaho Power service territories. Notably, both of these utilities exclude larger customers from their decoupling mechanisms.

**Q. What is your recommendation to the Commission on this issue?**

A. I recommend that the Commission reject APS's decoupling proposal for all customers. If, however, some form of revenue decoupling is approved by the Commission, I recommend that customers with billing demands greater than 400 kW (i.e., Rates 32-L, 34, and 35) be excluded from the program. Rates 34 and 35 already have rate designs that insulate APS from loss of fixed-cost recovery from energy conservation. The design of Rate 32-L can be modified to achieve a comparable result.

**Q. If larger customers are excluded from the decoupling mechanism, would other customers be forced to bear decoupling-related costs caused by the larger customers?**

A. Absolutely not. If a customer group is excluded from the decoupling mechanism, they would neither pay the EIA *nor shift costs to the EIA for recovery*. The only decoupling costs that should be recorded by APS would be those directly attributable to the participating classes. Consequently, no costs would be shifted from non-participants to participants.

## ENVIRONMENTAL AND RELIABILITY ACCOUNT

**Q. What has APS proposed with respect to the adoption of an Environmental and Reliability Account?**

A. As discussed by Mr. Snook, APS is proposing that the Commission approve an Environmental and Reliability Account ("ERA"). The ERA would allow APS to pass through to customers the carrying costs of environmental improvement projects and generation plant capacity acquisition and additions. The carrying costs would consist of a return on ERA-qualified investments at APS's most-recently-approved weighted average cost of capital; depreciation expense; income taxes; property taxes; deferred taxes and tax credits (where appropriate); and operations and maintenance expense. The ERA would be reset each year.

**Q. Do you support adoption of the proposed ERA?**

A. No. If adopted, the ERA would be a vehicle for potentially flowing through hundreds of millions of dollars of costs to APS customers without the scrutiny of a rate case. It is an example of unwarranted single-issue ratemaking.

**Q. What is single-issue ratemaking?**

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers the standard practice is to review and consider all relevant factors, rather than just certain factors in isolation. Considering some costs or revenues in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. For example, the proposed ERA would allow APS to earn a return on its new investment and charge customers for depreciation expenses associated with that new investment without recognizing that its existing rate base would have depreciated to a lower value at the time the ERA is charged to customers. In short, it exacerbates the problems associated with APS's practice of seeking to set rates using unsynchronized test periods. In my opinion, the proposed ERA is a classic example of an application of single-issue ratemaking that is not in the public interest. The Commission should view such proposals with great wariness. I recommend that it be rejected.

**Q. Are you aware of any other utilities in the western United States that have such an adjustment mechanism in place?**

A. No. I have researched the tariffs of the major investor-owned utilities in the western United States. While California utilities have "attrition adjustments," I am not aware of any utility in the West that has in place the type of adjustment mechanism that APS is seeking.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

# APPENDIX A

**KEVIN C. HIGGINS**
**Principal, Energy Strategies, L.L.C.**
**215 South State St., Suite 200, Salt Lake City, UT 84111**

# Vitae

## PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

## EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

## SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

**EXPERT TESTIMONY**

"In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina," **North Carolina** Utilities Commission, Docket No. E-7, Sub 989. Direct testimony submitted October 31, 2011.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan," Public Utilities Commission of **Ohio**," Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, et al. Direct testimony in support of Stipulation submitted October 28, 2011.

"*Application of Nevada Power Company* d/b/a NV Energy, for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers, Begin to Recover the Costs of Constructing Harry Allen Combined Cycle, Goodsprings and Other Generating, Transmission and Distribution Plant Additions, and to Reflect Changes in Cost of Service and for Relief Properly Thereto; Application of Nevada Power Company d/b/a/ NV Energy for Approval of New and Revised Depreciation Rates for Its Electrical Operations; Application of Sierra Pacific Power Company d/b/a/ NV Energy for a Determination of the Reasonableness of the Ely Energy Center Project Development Costs and for Authority to Reclassify Those Costs from a Deferred Debit to a Regulatory Asset with an Appropriate Carrying Charge," Public Utilities Commission of **Nevada**, Docket Nos. 11-06006, 11-06007, and 11-06008. Direct testimony submitted October 12, 2011. Cross examined November 2, 2011.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service in Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-11-08. Direct testimony submitted October 7, 2011. Rebuttal testimony submitted November 16, 2011.

"In the Matter of the Application of Public Service Company of Colorado for an Order Approving Regulatory Treatment of Margins Earned from Certain Renewable Energy Credit and Energy Transactions and Petition for Declaratory Order Clarifying the Meaning of the Phrase) "Transactions Executed" as that Phrase Is Used in the Settlement Agreement Approved in Docket No. 09A-602E," **Colorado** Public Utilities Commission, Docket No. 11A-510E. Answer testimony submitted September 19, 2011. Cross examined October 20, 2011.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan," Public Utilities Commission of **Ohio**," Case Nos. 11-346-EL-SSO and Case No. 11-348-EL-SSO. "In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain

Accounting Authority," Case Nos. 11-349-EL-AAM and 11-350-EL-AAM. Direct testimony submitted July 25, 2011.

"In the Matter of the Application of Appalachian Power Company for an Adjustment of Electric Base Rates," **Virginia** Corporation Commission, Case No. PUE-2011-00037. Direct testimony submitted July 20, 2011.

"Ameren Illinois Company d/b/a Ameren Illinois, Proposed General Increase in Electric Delivery Service Rates; Ameren Illinois Company d/b/a Ameren Illinois, Proposed General Increase in Natural Gas Rates," **Illinois** Commerce Commission, Docket Nos. 11-0279 and 11-0282. Direct testimony submitted June 29, 2011. Rebuttal testimony submitted August 23, 2011.

"In the Matter of PacifiCorp, dba Pacific Power 2012 Transition Adjustment Mechanism," Public Utility Commission of **Oregon**, Docket No. UE-227. Reply testimony submitted June 24, 2011. Rebuttal testimony submitted August 16, 2011.

"In the Matter of the Application of Rocky Mountain Power to Implement a Permanent Avoided Cost Methodology for Customers That Do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from Qualifying Facilities," **Wyoming** Public Service Commission, Docket No. 20000-388-EA-11. Direct testimony submitted May 26, 2011. Cross examined August 2, 2011.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of Its Retail Electric Rates Pursuant to Advice Notice Nos. 397 and 32 (Former TNMP Services), Public Service Company of New Mexico, Applicant," **New Mexico** Public Regulation Commission, Case No. 10-00086-UT. Direct testimony in Opposition to Stipulation submitted April 14, 2011. Cross examined May 12, 2011.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $97.9 Million Per Year or 17.3 Percent," **Wyoming** Public Service Commission, Docket No. 20000-384-ER-10. Direct testimony submitted April 11, 2011. Cross answer testimony submitted May 6, 2011. Stipulation testimony submitted June 9, 2011. Cross examined June 20, 2011.

"In the Matter of the Application of Rocky Mountain Power for Approval of an Adjustment to the Demand-Side Management Program and Suspend Schedule 191 Rate Surcharges," **Wyoming** Public Service Commission, Docket No. 20000-383-ER-10. Direct testimony submitted March 30, 2011. Cross examined May 11, 2011.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 10-035-124. Direct testimony submitted March 9, 2011 (test period); May 26, 2011 (revenue requirement); and June 2, 2011 (cost of service). Rebuttal testimony submitted March 17, 2011 (test period) and June 30, 2011 (revenue requirement). Surrebuttal testimony submitted July 19, 2011 (revenue requirement). Cross examined March 24, 2011 (test period); August 3, 2011 (revenue requirement stipulation); and August 8, 2011 (cost of service stipulation).

"Application of Nevada Power Company d/b/a NV Energy to Establish Interim Base Energy Efficiency Program Rates and Base Energy Efficiency Implementation Rates Pursuant To NRS 704.785 and the Order Issued in Docket No. 09-07016; Application of Sierra Pacific Power Company d/b/a NV Energy to Establish Interim Base Energy Efficiency Program Rates and Base Energy Efficiency Implementation Rates Pursuant to NRS704.785 and the Order Issued in Docket No. 09-07016," Public Utilities Commission of **Nevada,** Docket Nos. 10-10024 and 10-10025. Direct testimony submitted March 8, 2011. Cross examined March 29, 2011.

"2010 Puget Sound Energy Tariff Filing," **Washington** Utilities and Transportation Commission, Docket No. UG-101644. Joint testimony in support of stipulation filed February 11, 2011. Oral testimony in support of stipulation presented March 1, 2011.

"Petition of Duke Energy Indiana, Inc. for Approval to Offer Additional Energy Efficiency Programs; For Approval of Program Cost Recovery, Lost Revenues and Incentives Pursuant to 170 IAC 4-8-5, 170 IAC 4-8-6, and 170 IAC 4-8-7; Authority to Defer Costs Pending Approval and for Authority to Implement Annual Tracking Mechanism," **Indiana** Utility Regulatory Commission, Cause No. 43955. Direct testimony submitted February 9, 2011.

"In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service," Public Utilities Commission of **Ohio**, Case No. 10-2586-EL-SSO. Direct testimony submitted December 21, 2010. Deposed December 22, 2010. Cross examined January 18, 2011.

"In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating To Its DSM Plan, Including Long-Term Electric Energy Savings Goals and Incentives," **Colorado** Public Utilities Commission, Docket No. 10A-554EG. Answer testimony submitted December 17, 2010. Cross answer testimony submitted February 4, 2011. Cross examined March 2, 2011.

"In the Matter of Appalachian Power Company and Wheeling Power Company," Public Service Commission of **West Virginia**, Case No. 10-0699-E-42T. Direct testimony submitted November 10, 2010. Rebuttal testimony submitted November 23, 2010.

"In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Populus to Ben Lomond Transmission Line and Dunlap I Wind Project," **Utah** Public Service Commission, Docket No. 10-035-89. Confidential direct testimony submitted October 26, 2010. Oral testimony in support of stipulation presented December 6, 2010.

"In the Matter of Georgia Power Company's 2010 Rate Case," **Georgia** Public Service Commission, Docket No. 31958. Direct testimony submitted October 22, 2010. Cross examined November 8, 2010.

"In the Matter of the Application of Rocky Mountain Power for Authority to Implement an Energy Cost Adjustment Mechanism," **Wyoming** Public Service Commission, Docket No. 20000-368-EA-10. Direct testimony submitted September 10, 2010. Cross examined November 9, 2010.

"Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs," Public Utility Commission of **Texas**, Docket No. 37744. Direct testimony submitted June 9, 2010.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon**, Docket No. UE-215. Opening testimony submitted June 4, 2010. Joint testimony in support of stipulation submitted August 2, 2010.

"In the Matter of the Application of Duke Energy Ohio, Inc. to Establish and Adjust the Initial Level of its Distribution Reliability Rider," Public Utilities Commission of **Ohio**, Case No. 09-1946-EL-RDR. Direct testimony submitted May 18, 2010.

"In the Matter of PacifiCorp, dba Pacific Power, 2011 Transition Adjustment Mechanism," Public Utility Commission of **Oregon**, Docket No. UE-216. Reply testimony submitted May 12, 2010. Joint testimony in support of stipulation submitted July 26, 2010.

"In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and the Dave Johnston Generation Unit 3 Emissions Control Measure," **Utah** Public Service Commission, Docket No. 10-035-13. Direct testimony submitted April 26, 2010.

"In the Matter of a Notice of Inquiry into Energy Efficiency," **Arkansas** Public Service Commission, Docket No. 10-010-U. Direct testimony submitted March 23, 2010. Cross examined October 18, 2010.

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission," Docket No. 09-084-U. Direct testimony submitted February 26, 2010.

"In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate

Increase of Approximately $70.9 Million per Year or 13.7 Percent," **Wyoming** Public Service Commission, Docket No. 20000-352-ER-09. Direct testimony submitted February 16, 2010. Cross answer testimony submitted March 15, 2010. Direct settlement testimony submitted March 31, 2010. Cross examined April 23, 2010.

"Amended Petition of Puget Sound Energy, Inc., for an Order Authorizing the Use of the Proceeds from the Sale of Renewable Energy Credits and Carbon Financial Instruments," **Washington** Utilities and Transportation Commission, Docket No. UE-070725. Response testimony submitted January 28, 2010.

"Application of Appalachian Power Company for a 2009 Statutory Review of Rates Pursuant to § 56.585.1 A of the Code of Virginia," **Virginia** Corporation Commission, Case No. PUE-2009-00030. Direct testimony submitted December 28, 2009. Additional direct testimony submitted March 8, 2010. Cross examined April 1, 2010.

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications with Reconciliation Mechanism and Tariffs for Generation Service," Public Utilities Commission of **Ohio**, Case No. 09-906-EL-SSO. Direct testimony submitted December 4, 2009. Deposed December 10, 2009.

"2009 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-090704 and UG-090705. Response testimony submitted November 17, 2009. Joint testimony in support of stipulation submitted January 8, 2010.

"In the Matter of the Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism," **Utah** Public Service Commission, Docket No. 09-035-15. Direct Phase I testimony submitted November 16, 2009. Direct Phase II testimony submitted August 4, 2010. Rebuttal Phase II testimony submitted September 15, 2010. Surrebuttal Phase I testimony submitted January 5, 2010. Surrebuttal Phase II testimony submitted October 13, 2010. Cross examined January 12, 2010 (Phase I) and November 2, 2010 (Phase II).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 09-035-23. Direct testimony submitted October 8, 2009. Rebuttal testimony submitted November 12, 2009. Surrebuttal testimony submitted November 30, 2009. Cross examined December 15-16, 2009.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric," **Colorado** Public Utilities Commission, Docket No. 09AL-299E. Answer testimony submitted October 2, 2009. Surrebuttal testimony submitted December 18, 2009.

"In the Matter of the Applications of Westar Energy, Inc., and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service," **Kansas** Corporation Commission, Docket No. 09-WSEE-925-RTS. Direct testimony submitted September 30, 2009. Cross answer testimony submitted October 16, 2009.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates; Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates; Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates; Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Gas Delivery Service Rates; Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates; Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 09-0306, 09-0307, 09-0308, 09-0309, 09-0310, and 09-0311. Direct testimony submitted September 28, 2009. Rebuttal testimony submitted November 20, 2009.

"In the Matter of the Complaint of Nucor Steel-Indiana, a Division of Nucor Corporation against Duke Energy Indiana, Inc. for Determination of Reasonable and Just Charges and Conditions for Electric Service and Request for Expedited Adjudication," **Indiana** Utility Regulatory Commission, Cause No. 43754. Direct testimony submitted September18, 2009. Rebuttal testimony submitted December 3, 2009. Testimony withdrawn pursuant to settlement agreement.

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon," Public Utility Commission of **Oregon,** Docket No. UE-210. Reply testimony submitted July 24, 2009. Joint testimony in support of stipulation submitted September 25, 2009.

"In The Matter of the Application of Rocky Mountain Power to Establish an Avoided Cost Methodology for Customers That Do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from Qualifying Facilities," **Wyoming** Public Service Commission, Docket No. 20000-342-EA-09. Direct testimony submitted July 21, 2009. Cross examined September 1, 2009.

"In the Matter of PacifiCorp, dba Pacific Power, 2010 Transition Adjustment Mechanism," Public Utility Commission of **Oregon,** Docket No. UE-207. Reply testimony submitted July 14, 2009. Joint testimony in support of stipulation submitted September 25, 2009.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy,"

**Michigan** Public Service Commission, Case No. U-15768. Direct testimony submitted July 9, 2009. Rebuttal testimony submitted July 30, 2009.

"In the Matter of the Investigation of Westar Energy, Inc., and Kansas Gas and Electric Company to Consider the Issue of Rate Consolidation and Resulting Rate Design," **Kansas** Corporation Commission," Docket No. 09-WSEE-641-GIE. Direct testimony submitted June 26, 2009. Cross examined August 17, 2009.

"Illinois Commerce Commission on Its Own Motion vs Commonwealth Edison Company, Investigation of Rate Design Pursuant to Section 9-250 of the Public Utilities Act," **Illinois** Commerce Commission, Docket No. 08-0532. Direct testimony submitted May 22, 2009.

"In the Matter of the Application of Duke Energy Kentucky, Inc. for Approval of Energy Efficiency Plan, Including an Energy Efficiency Rider and Portfolio of Energy Efficiency Programs," **Kentucky** Public Service Commission, Case No. 2008-00495. Direct testimony submitted May 11, 2009.

"In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed Pursuant to NRS§704.110(3) and NRS §704.110(4) for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers, Begin to Recover the Costs of Acquiring the Bighorn Power Plant, Constructing the Clark Peakers, Environmental Retrofits and Other Generating, Transmission and Distribution Plant Additions, to Reflect Changes in Cost of Service and for Relief Properly Related Thereto, Public Utilities Commission of **Nevada**, Docket No. 08-12002. Direct testimony submitted April 14, 2009 (revenue requirement) and April 21, 2009 (cost of service/rate design). Cross examined May 6, 2009.

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, *Et Seq.*, for the Implementation of an Electric Distribution System "SmartGrid" and Advanced Metering Infrastructure, Distribution Automation Investments, and a Distribution Renewable Generation Demonstration Project and Associated Accounting and Rate Recovery Mechanisms, Including a Ratemaking Proposal to Update Distribution Rates Annually and a "Lost Revenue" Recovery Mechanism, in Accordance with Ind. Code 8-1-2-42(a) and 8-1-2.5-1 *Et Seq.* and Preliminary Approval of the Estimated Costs and Scheduled Deployment of the Company's SmartGrid Initiative," **Indiana** Utility Regulatory Commission, Cause No. 43501. Direct testimony submitted February 27, 2009.

"In The Matter of the Application of Duke Energy Ohio for an Increase in Electric Distribution Rates," Public Utilities Commission of **Ohio**, Case No. 08-709-EL-AIR; "In the Matter of the Application of Duke Energy Ohio for Tariff Approval," Case No. 08-710-EL-ATA; "In the Matter of the Application of Duke Energy Ohio for Approval to Change Accounting Methods," Case No. 08-711-EL-AAM. Direct testimony submitted February 26, 2009.

"In The Matter of the Amended Application of Rocky Mountain Power for Approval of a General Rate Increase of Approximately $28.8 Million per Year (6.1 Percent Overall Average Increase)", **Wyoming** Public Service Commission, Docket No. 20000-333-ER-08. Direct testimony submitted January 30, 2009. Summary of cross answer testimony submitted February 27, 2009. Settlement testimony submitted March 13, 2009. Cross examined March 24, 2009.

"In the Matter of the Application of Dayton Power and Light Company for Approval of Its Electric Security Plan," Public Utilities Commission of **Ohio**, Case No. 08-1094-EL-SSO; "In the Matter of the Application of Dayton Power and Light Company for Approval of Revised Tariffs, Case No. 08-1095-EL-ATA; "In the Matter of the Application of Dayton Power and Light Company for Approval of Certain Accounting Authority Pursuant to Ohio Rev. Code §4905.13," Case No. 08-1096-EL-AAM; In the Matter of the Application of Dayton Power and Light Company for Approval of Its Amended Corporate Separation Plan, Case No. 08-1097-EL-UNC. Direct testimony submitted January 26, 2009. Deposed February 6, 2009. Testimony withdrawn pursuant to stipulation filed February 24, 2009.

"Application of Oncor Electric Delivery Company LLC for Authority to Change Rates," Public Utility Commission of **Texas**, SOAH Docket No. 473-08-3681, PUC Docket No. 35717. Direct testimony submitted November 26, 2008. Cross examined February 3, 2009.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Its Electric Security Plan; An Amendment to Its Corporate Separation Plan; and the Sale of Certain Generating Assets", Public Utilities Commission of **Ohio**, Case No. 08-917-EL-SSO; "In the Matter of the Application of Ohio Power Company for Approval of Its Electric Security Plan; and an Amendment to Its Corporate Separation Plan," Case No. 08-918-EL-SSO. Direct testimony submitted October 31, 2008. Cross examined November 25, 2008.

"Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00252. Direct testimony submitted October 28, 2008.

"Application of Kentucky Utilities Company for an Adjustment of Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00251. Direct testimony submitted October 28, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-08-10. Direct testimony submitted October 24, 2008. Rebuttal testimony submitted December 3, 2008. Cross examined December 19, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service

Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 08-035-38. Direct testimony submitted October 7, 2008 (test period) and February 12, 2009 (revenue requirement). Cross examined October 28, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan," Public Utility Commission of **Ohio**, Case No. 08-935-EL-SSO. Direct testimony submitted September 29, 2008. Deposed October 13, 2008. Cross examined October 21, 2008.

"In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes In Their Charges for Electric Service," State Corporation Commission of **Kansas**, Docket No. 08-WSEE-1041-RTS. Direct testimony submitted September 29, 2008. Cross Answer testimony submitted October 8, 2008.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2008-00046. Direct testimony submitted September 26, 2008.

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications with Reconciliation Mechanism and Tariffs for Generation Service," Public Utility Commission of **Ohio**, Case No. 08-936-EL-SSO. Direct testimony submitted September 9, 2008. Deposed September 16, 2008.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return," **Arizona** Corporation Commission, Docket No. E-01345A-08-0172. Direct testimony submitted August 29, 2008 (interim rates), December 19, 2008 (revenue requirement), January 9, 2009 (cost of service, rate design), and July 1, 2009 (settlement agreement). Reply testimony submitted August 6, 2009 (settlement agreement). Cross examined September 16, 2008 (interim rates) and August 20, 2009 (settlement agreement).

"Verified Joint Petition of Duke Energy Indiana, Inc., Indianapolis Power & Light Company, Northern Indiana Public Service Company and Vectren Energy Delivery of Indiana, Inc. for Approval, if and to the Extent Required, of Certain Changes in Operations That Are Likely To Result from the Midwest Independent System Operator, Inc.'s Implementation of Revisions to Its Open Access Transmission and Energy Markets Tariff to Establish a Co-Optimized, Competitive Market for Energy and Ancillary Services Market; and for Timely Recovery of Costs Associated with Joint Petitioners' Participation in Such Ancillary Services Market," **Indiana** Utility

Regulatory Commission, Cause No. 43426. Confidential direct testimony submitted August 6, 2008. Confidential direct testimony in opposition to Settlement Agreement submitted November 12, 2008.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority," **Michigan** Public Service Commission, Case No. U-15244. Direct testimony submitted July 15, 2008. Rebuttal testimony submitted August 8, 2008.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-197. Direct testimony submitted July 9, 2008. Surrebuttal testimony submitted September 15, 2008.

"In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200, Cost-Based Supply Service," Public Utility Commission of **Oregon,** Docket No. UE-199. Reply testimony submitted June 23, 2008. Joint testimony in support of stipulation submitted September 4, 2008.

"2008 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-072300 and UG-072301. Response testimony submitted May 30, 2008. Cross-Answer testimony submitted July 3, 2008. Joint testimony in support of partial stipulations submitted July 3, 2008 (gas rate spread/rate design), August 12, 2008 (electric rate spread/rate design), and August 28, 2008 (revenue requirements). Cross examined September 3, 2008.

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, Et Seq., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code 8-1-2.5-1 Et Seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with Its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs in Its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests," **Indiana** Utility Regulatory Commission, Cause No. 43374. Confidential direct testimony submitted May 21, 2008 and October 27, 2008. Testimony withdrawn pursuant to stipulation, but re-submitted June 1, 2010. Confidential supplemental direct testimony submitted June 10, 2010. Application withdrawn by Duke Energy Indiana, June 2010.

"Cinergy Corp., Duke Energy Ohio, Inc., Cinergy Power Investments, Inc., Generating Facilities LLCs," **Federal Energy Regulatory Commission**, Docket No. EC-08-78-000. Affidavit filed May 14, 2008.

"Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs, Public Utility Commission of **Texas**, Docket No. 34800 [SOAH Docket No. 473-08-0334]. Direct testimony submitted April 11, 2008. Testimony withdrawn pursuant to stipulation.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates, Central Illinois Light Company d/b/a AmerenCILCO, Proposed General Increase in Gas Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589, 07-0590. Direct testimony submitted March 14, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Public Service Company of Colorado for Authority to Implement an Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Recovery and Incentives," **Colorado** Public Utilities Commission, Docket No. 07A-420E. Answer testimony submitted March 10, 2008. Cross examined April 25, 2008.

"An Investigation of the Energy and Regulatory Issues in Section 50 of Kentucky's 2007 Energy Act," **Kentucky** Public Service Commission, Administrative Case No. 2007-00477. Direct testimony submitted February 29, 2008. Supplemental direct testimony submitted April 1, 2008. Cross examined April 30, 2008.

"In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. E-01933A-07-0402. Direct testimony submitted February 29, 2008 (revenue requirement), March 14, 2008 (rate design), and June 12, 2008 (settlement agreement). Cross examined July 14, 2008.

"Commonwealth Edison Company Proposed General Increase in Electric Rates," **Illinois** Commerce Commission, Docket No. 07-0566. Direct testimony submitted February 11, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Questar Gas Company to File a General Rate Case," **Utah** Public Service Commission, Docket No. 07-057-13. Direct testimony submitted January 28, 2008 (test period), March 31, 2008 (rate of return), April 21, 2008 (revenue requirement), and August 18, 2008 (cost of service, rate spread, rate design). Rebuttal testimony submitted September 22, 2008 (cost of service, rate spread, rate design). Surrebuttal testimony submitted May 12, 2008 (rate of return) and October 7, 2008 (cost of service, rate spread, rate design). Cross examined February 8, 2008 (test period), May 21, 2008 (rate of return), and October 15, 2008 (cost of service, rate spread, rate design).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," **Utah** Public Service Commission, Docket No. 07-035-93. Direct testimony submitted January 25, 2008 (test period), April 7, 2008 (revenue requirement), and July 21, 2008 (cost of service, rate design). Rebuttal testimony submitted September 3, 2008 (cost of service, rate design). Surrebuttal testimony submitted May 23, 2008 (revenue requirement) and September 24, 2008 (cost of service, rate design). Cross examined February 7, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals," Public Utilities Commission of **Ohio**, Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, and 07-554-EL-UNC. Direct testimony submitted January 10, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately $36.1 Million per Year, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff," **Wyoming** Public Service Commission, Docket No. 20000-277-ER-07. Direct testimony submitted January 7, 2008. Cross examined March 6, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service to Electric Customers in the State of Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-07-8. Direct testimony submitted December 10, 2007. Cross examined January 23, 2008.

"In The Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution Of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-15245. Direct testimony submitted November 6, 2007. Rebuttal testimony submitted November 20, 2007.

"In the Matter of Montana-Dakota Utilities Co., Application for Authority to Establish Increased Rates for Electric Service," **Montana** Public Service Commission, Docket No. D2007.7.79. Direct testimony submitted October 24, 2007.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 334," **New Mexico** Public Regulation Commission, Case No. 07-0077-UT. Direct testimony submitted October 22, 2007. Rebuttal testimony submitted November 19, 2007. Cross examined December 12, 2007.

"In The Matter of Georgia Power Company's 2007 Rate Case," **Georgia** Public Service Commission, Docket No. 25060-U. Direct testimony submitted October 22, 2007. Cross examined November 7, 2007.

"In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the MidAmerican Energy Holdings Company Transaction," **Utah** Public Service Commission, Docket No. 07-035-04; "In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order To Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization," Docket No. 06-035-163; "In the Matter of the Application of Rocky Mountain Power for an Accounting Order for Costs related to the Flooding of the Powerdale Hydro Facility," Docket No. 07-035-14. Direct testimony submitted September 10, 2007. Surrebuttal testimony submitted October 22, 2007. Cross examined October 30, 2007.

"In the Matter of General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.," **Kentucky** Public Service Commission, Case No. 2006-00472. Direct testimony submitted July 6, 2007. Supplemental direct testimony submitted March 18, 2008.

"In the Matter of the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Service," **Arizona** Corporation Commission, Docket No. E-03964A-06-0168. Direct testimony submitted July 3, 2007. Rebuttal testimony submitted January 17, 2008 and February 7, 2007.

"Application of Public Service Company of Oklahoma for a Determination that Additional Electric Generating Capacity Will Be Used and Useful," **Oklahoma** Corporation Commission, Cause No. PUD 200500516; "Application of Public Service Company of Oklahoma for a Determination that Additional Baseload Electric Generating Capacity Will Be Used and Useful," Cause No. PUD 200600030; "In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Granting Pre-Approval to Construct Red Rock Generating Facility and Authorizing a Recovery Rider," Cause No. PUD200700012. Responsive testimony submitted May 21, 2007. Cross examined July 26, 2007.

"Application of Nevada Power Company for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto," Public Utilities Commission of **Nevada**, Docket No. 06-11022. Direct testimony submitted March 14, 2007 (Phase III – revenue requirements) and March 19, 2007 (Phase IV – rate design). Cross examined April 10, 2007 (Phase III – revenue requirements) and April 16, 2007 (Phase IV – rate design).

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission, Docket No. 06-101-U. Direct testimony submitted February 5, 2007. Surrebuttal testimony submitted March 26, 2007.

"Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Rule 42T Application to Increase Electric Rates and Charges," Public Service Commission of **West Virginia**, Case No. 06-0960-E-42T; "Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Information Required for Change of Depreciation Rates Pursuant to Rule 20," Case No. 06-1426-E-D. Direct and rebuttal testimony submitted January 22, 2007.

"In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Missouri Service Areas," **Missouri** Public Service Commission, Case No. ER-2007-0004. Direct testimony submitted January 18, 2007 (revenue requirements) and January 25, 2007 (revenue apportionment). Supplemental direct testimony submitted February 27, 2007.

"In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103, **Arizona** Corporation Commission, Docket No. E-01933A-05-0650. Direct testimony submitted January 8, 2007. Surrebuttal testimony filed February 8, 2007. Cross examined March 8, 2007.

"In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area," **Missouri** Public Service Commission, Case No. ER-2007-0002. Direct testimony submitted December 15, 2006 (revenue requirements) and December 29, 2006 (fuel adjustment clause/cost-of-service/rate design). Rebuttal testimony submitted February 5, 2007 (cost-of-service). Surrebuttal testimony submitted February 27, 2007. Cross examined March 21, 2007.

"In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates," **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission," Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (revenue requirements) and September 1, 2006 (cost-of-service/rate design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric," **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon,** Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006. Rebuttal testimony submitted August 8, 2007. Cross examined September 19, 2007.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct and rebuttal testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska,** Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted

September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission,** EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service

Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01; "In the Matter of the Application of Rocky Mountain Power for an Order Approving an Amendment to Its Power Purchase Agreement with Sunnyside Cogeneration Associates," Docket Nos. 05-035-46, and 07-035-99. Direct testimony submitted July 8, 1996. Oral testimony provided March 18, 2008.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 20000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

**OTHER RELATED ACTIVITY**

Participant, Wyoming Load Growth Collaborative, March 2008 to January 2009.

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to December 1999. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

KCH-1

**Comparison of APS and AECC**
**Computation of Increase in Gross Revenue Requirements**
**For the Adjusted Test Year Ending December 31, 2010**
**(Thousands of Dollars)**

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | | ACC Jurisdiction | | |
| Line No. | Description | APS Original Cost[1] | AECC Adjustments | AECC Original Cost |
| 1 | Adjusted Rate Base - Original Cost | $ 5,720,277 | $ (305,254) | $ 5,415,023 |
| 2 | Adjusted Operating Income | 474,356 | 25,852 | 500,208 |
| 3 | Current Rate of Return | 8.29% | 0.95% | 9.24% |
| 4 | Required Operating Income | 507,389 | (27,076) | 480,313 |
| 5 | Requested Rate of Return | 8.87% | 0.00% | 8.87% |
| 6 | Adjusted Operating Income Deficiency | 33,033 | (52,928) | (19,895) |
| 7 | Gross Revenue Conversion Factor | 1.6532 | | 1.6532 |
| 8 | Adjusted Increase in Base Revenue Requirement | $ 54,610 | $ (87,501) | $ (32,891) |
| Line No. | Description | APS FV Cost[1] | AECC Adjustments | AECC FV Cost |
| 9 | Adjusted Rate Base - RCND | 10,728,532 | (305,254) | 10,423,278 |
| 10 | Adjusted Rate Base - Fair Value (FV) | 8,224,405 | (305,254) | 7,919,150 |
| 11 | Requested Rate of Return with 1% FV Increment | 6.47% | 0.00% | 6.47% |
| 12 | Required Operating Income | 532,119 | (19,751) | 512,368 |
| 13 | Incremental Fair Value Required Operating Income | 24,730 | 7,325 | 32,055 |
| 14 | Gross Revenue Conversion Factor | 1.6532 | | 1.6532 |
| 15 | Fair Value Increment | 40,884 | 12,109 | 52,993 |
| 16 | Requested Increase in Base Revenue Requirement | $ 95,494 | $ (75,392) | $ 20,102 |
| 17 | Total Present Sales Revenue to Ultimate Retail Customers | $ 2,868,858 | $ - | $ 2,868,858 |
| 18 | Adjusted Percentage Increase | 3.33% | -2.63% | 0.70% |

Data Sources:
1. APS Schedule A-1.

## AECC Original Cost Rate Base
### For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|---|---|
| | | APS Application[1] Adjusted Test Year Ended 12/31/2010 | | APS - Identified Updates[2] for the Test Year Ended 12/31/2010 | | AECC Post Test Period Plant Additions Adjustment | |
| Line No. | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| 1 | Gross Utility Plant in Service | $ 14,629,039 | $ 12,467,614 | $ (37,241) | $ (36,108) | $ (487,308) | $ (473,580) |
| 2 | Less: Accumulated Depreciation and Amortization | 5,719,580 | 5,015,939 | (206) | (199) | (253,320) | (246,463) |
| 3 | Net Utility Plant in Service | 8,909,459 | 7,451,675 | (37,035) | (35,909) | (233,988) | (227,117) |
| 4 | Less: Total Deductions | 3,720,403 | 3,274,062 | (648) | (626) | (25,407) | (24,572) |
| 5 | Plus: Total Additions | 1,654,793 | 1,542,664 | 738 | 502 | 1,504 | 1,043 |
| 6 | Total Rate Base | $ 6,843,849 | $ 5,720,277 | $ (35,649) | $ (34,781) | $ (207,077) | $ (201,503) |

Data Source:
1. APS SFR Schedule B-1, p. 1 of 2.
2. APS Technical Conference, October 27, 2011.

## AECC RCND Rate Base
### For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

| | | APS Adjusted[1] Test Year Ended 12/31/2010 | | APS - Adjusted (Update) Test Year Ended 12/31/2010[2] | | AECC Post Test Period Plant Additions Adjustment | |
|---|---|---|---|---|---|---|---|
| Line No. | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| 7 | Gross Utility Plant in Service | $ 27,351,712 | $ 23,201,276 | $ (37,241) | $ (36,108) | $ (487,308) | $ (473,580) |
| 8 | Less: Accumulated Depreciation and Amortization | 10,327,557 | 9,014,923 | (206) | (199) | (253,320) | (246,463) |
| 9 | Net Utility Plant in Service | 17,024,155 | 14,186,353 | (37,035) | (35,909) | (233,988) | (227,117) |
| 10 | Less: Total Deductions | 5,846,890 | 5,000,485 | (648) | (626) | (25,407) | (24,572) |
| 11 | Plus: Total Additions | 1,654,793 | 1,542,664 | 738 | 502 | 1,504 | 1,043 |
| 12 | Total Rate Base | $ 12,832,058 | $ 10,728,532 | $ (35,649) | $ (34,781) | $ (207,077) | $ (201,503) |

Data Source:
1. APS SFR Schedule B-1, p. 2 of 2.
2. APS Technical Conference, October 27, 2011.

AECC Original Cost Rate Base
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| | | AECC Renewable Generation Cost Above Market Adj. | | AECC Adjusted Test Year Ended 12/31/2010 | |
| Line No. | Description | Total Co. | ACC | Total Co. | ACC |
| 1 | Gross Utility Plant in Service | $ (73,032) | $ (70,549) | $ 14,031,458 | $ 11,887,377 |
| 2 | Less: Accumulated Depreciation and Amortization | (943) | (911) | 5,465,111 | 4,768,367 |
| 3 | Net Utility Plant in Service | (72,089) | (69,638) | 8,566,347 | 7,119,011 |
| 4 | Less: Total Deductions | (691) | (668) | 3,693,657 | 3,248,197 |
| 5 | Plus: Total Additions | 0 | 0 | 1,657,035 | 1,544,209 |
| 6 | **Total Rate Base** | $ (71,398) | $ (68,970) | $ 6,529,725 | $ 5,415,023 |

AECC RCND Rate Base
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

| | | | | | |
|---|---|---|---|---|---|
| | | AECC Renewable Generation Cost Above Market Adj. | | AECC Adjusted Test Year Ended 12/31/2010 | |
| Line No. | Description | Total Co. | ACC | Total Co. | ACC |
| 1 | Gross Utility Plant in Service | $ (73,032) | $ (70,549) | $ 26,754,131 | $ 22,621,039 |
| 2 | Less: Accumulated Depreciation and Amortization | (943) | (911) | 10,073,088 | 8,767,351 |
| 3 | Net Utility Plant in Service | (72,089) | (69,638) | 16,681,043 | 13,853,689 |
| 4 | Less: Total Deductions | (691) | (668) | 5,820,144 | 4,974,620 |
| 5 | Plus: Total Additions | 0 | 0 | 1,657,035 | 1,544,209 |
| 6 | Total Rate Base | $ (71,398) | $ (68,970) | $ 12,517,934 | $ 10,423,278 |

AECC Income Statement
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

| Line No. | (a) Description | (b) APS Application[1] Adjusted Total Company | (c) APS Application[1] Adjusted ACC Jurisdiction | (d) APS - Identified Updates[2] for the Total Company | (e) APS - Identified Updates[2] for the ACC Jurisdiction | (f) AECC Post Test Period Plant Additions Adjustment Total Company | (g) AECC Post Test Period Plant Additions Adjustment ACC Jurisdiction | (h) AECC Mar. 2012 Pro Forma Sales Growth Adjustment Total Company | (i) AECC Mar. 2012 Pro Forma Sales Growth Adjustment ACC Jurisdiction |
|---|---|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | | | |
| 1 | Revenues from Base Rates | $ 2,952,324 | $ 2,868,858 | $ 0 | $ 0 | $ 0 | $ 0 | $ 34,852 | $ 34,852 |
| 2 | Revenues from Surcharges | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Other Eelctric Revenues | 136,849 | 121,013 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | Total | 3,089,173 | 2,989,871 | 0 | 0 | 0 | 0 | 34,852 | 34,852 |
| | Operating Expenses: | | | | | | | | |
| 5 | Electric Fuel and Purchased Power | 1,040,884 | 1,015,598 | (9,575) | (9,575) | 0 | 0 | 10,966 | 10,966 |
| 6 | Operations and Maintenance Excluding Fuel Expense | 707,084 | 808,018 | 4,940 | 4,574 | 0 | 0 | 0 | 0 |
| 7 | Depreciation and Amortization | 405,150 | 352,026 | (1,700) | (1,650) | (11,154) | (10,826) | 0 | 0 |
| 8 | Income Taxes | 226,358 | 200,456 | 3,311 | 3,381 | 7,819 | 7,598 | 9,437 | 9,437 |
| 9 | Other Taxes | 162,770 | 139,417 | (1,000) | (881) | (2,548) | (2,481) | 0 | 0 |
| 10 | Total | 2,542,246 | 2,515,515 | (4,024) | (4,151) | (5,883) | (5,709) | 20,403 | 20,403 |
| 11 | Operating Income | 546,927 | 474,356 | 4,024 | 4,151 | 5,883 | 5,709 | 14,449 | 14,449 |
| | Other Income (Deductions) | | | | | | | | |
| 12 | Income Taxes | 4,975 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Allowance for Funds Used During Construction | 22,066 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Other Income (Deductions) | 8,956 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Other Expenses | (15,859) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | Total | 20,138 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Income Before Interest Deductions | 567,065 | 474,356 | 4,024 | 4,151 | 5,883 | 5,709 | 14,449 | 14,449 |
| | Interest Deductions: | | | | | | | | |
| 18 | Interest on Long -Term Debt | 205,209 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | Interest on Short Term Borrowings | 8,267 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | Debt Discount, Premium and Expense | 4,559 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | Allowance for Borrowed Funds Used During Construction | (16,479) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | Total | 201,556 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | Net Income | $ 365,509 | $ 474,356 | $ 4,024 | $ 4,151 | $ 5,883 | $ 5,709 | $ 14,449 | $ 14,449 |

Data Source:
1. APS SFR Schedule C-1.
2. APS Technical Conference, October 27, 2011.

# AECC Income Statement
## For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| | | AECC Renewable Generation Cost Above Market Cost of Conventional Generation | | AECC Proforma | |
| Line No. | Description | Total Company | ACC Jurisdiction | Total Company | ACC Jurisdiction |
| | Electric Operating Revenues | | | | |
| 1 | Revenues from Base Rates | $ 0 | $ 0 | $ 2,987,176 | $ 2,903,710 |
| 2 | Revenues from Surcharges | 0 | 0 | 0 | 0 |
| 3 | Other Eelctric Revenues | 0 | 0 | 136,849 | 121,013 |
| 4 | Total | | | 3,124,025 | 3,024,723 |
| | Operating Expenses: | | | | |
| 5 | Electric Fuel and Purchased Power | 0 | 0 | 1,042,275 | 1,016,989 |
| 6 | Operations and Maintenance Excluding Fuel Expense | (1,232) | (1,190) | 710,792 | 811,402 |
| 7 | Depreciation and Amortization | (2,426) | (2,343) | 389,870 | 337,206 |
| 8 | Income Taxes | 2,414 | 2,332 | 249,339 | 223,204 |
| 9 | Other Taxes | (354) | (342) | 158,868 | 135,713 |
| 10 | Total | (1,598) | (1,543) | 2,551,144 | 2,524,515 |
| 11 | Operating Income | 1,598 | 1,543 | 572,880 | 500,208 |
| | Other Income (Deductions) | | | | |
| 12 | Income Taxes | 0 | 0 | 4,975 | 0 |
| 13 | Allowance for Funds Used During Construction | 0 | 0 | 22,066 | 0 |
| 14 | Other Income (Deductions) | 0 | 0 | 8,956 | 0 |
| 15 | Other Expenses | 0 | 0 | (15,859) | 0 |
| 16 | Total | 0 | 0 | 20,138 | 0 |
| 17 | Income Before Interest Deductions | 1,598 | 1,543 | 593,018 | 500,208 |
| | Interest Deductions: | | | | |
| 18 | Interest on Long -Term Debt | 0 | 0 | 205,209 | 0 |
| 19 | Interest on Short Term Borrowings | 0 | 0 | 8,267 | 0 |
| 20 | Debt Discount, Premium and Expense | 0 | 0 | 4,559 | 0 |
| 21 | Allowance for Borrowed Funds Used During Construction | 0 | 0 | (16,479) | 0 |
| 22 | Total | 0 | 0 | 201,556 | 0 |
| 23 | Net Income | $ 1,598 | $ 1,543 | $ 391,462 | $ 500,208 |

KCH-2

## AECC RECOMMENDED RATE BASE ADJUSTMENT TO POST TEST YEAR PLANT ADDITIONS TO REFLECT 18-MONTH AVERAGE OF POST TEST PERIOD ADDITIONS

**ACC JURISDICTION**
**(Thousands of Dollars)**

| Line No. | Description | AECC Solar Original Cost | Adjustment Solar Original Cost | AECC Solar @ 36% Original Cost | Line No. |
|---|---|---|---|---|---|
| *1.* | Adjusted Rate Base | $ 375,001 | $ (201,503) | $ 173,498 | *1.* |
| *2.* | Adjusted Operating Income | (18,882) | 5,709 | (13,173) | *2.* |
| *3.* | Current Rate of Return | -5.04% | -2.83% | -7.59% | *3.* |
| *4.* | Required Operating Income | 33,263 | (17,874) | 15,389 | *4.* |
| *5.* | Required Rate of Return | 8.87% | 8.87% | 8.87% | *5.* |
| *6.* | Adjusted Operating Income Deficiency | 52,145 | (23,583) | 28,562 | *6.* |
| *7.* | Gross Revenue Conversion Factor | 1.6532 | 1.6532 | 1.6532 | *7.* |
| *8.* | Requested Increase in Base Revenue Requirements | $ 86,206 | $ (38,988) | $ 47,218 | *8.* |
| | Fair Value Impact | | | | |
| *9.* | Estimated Fair Value Increment Revenue Requirement Impact [See Attachment KCH-4, p. 2 of 4] | | 7,996 | | *9.* |
| *10.* | Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16] | | $ (30,992) | | *10.* |

# AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions

**Rate Base Impact Summary**

**(Includes Renewable, Fossil, Nuclear, Distribution, General, and Intangible Plant Additions)**

| Line No. | Description | Updated 9-20-2011 Post-Test Year Plant Additions | | 18-Month Average Post-Test Year Plant Additions | | Increase/(Decrease) From As Filed Pro Forma | | Line No. |
|---|---|---|---|---|---|---|---|---|
| | | Total Co. (A) | ACC (B) | Total Co. (C) | ACC (D) | Total Co. (E) | ACC (F) | |
| 1. | Gross Utility Plant in Service | $ 949,526 | $ 922,756 | $ 462,218 | $ 449,176 | $ (487,308) | $ (473,580) | 1. |
| 2. | Less: Accumulated Depreciation & Amort. | 504,009 | 490,384 | 250,689 | 243,921 | (253,320) | (246,463) | 2. |
| 3 | Net Utility Plant in Service | 445,517 | 432,372 | 211,529 | 205,255 | (233,988) | (227,117) | 3 |
| 4. | Less: Total Deductions | 49,655 | 48,024 | 24,248 | 23,452 | (25,407) | (24,572) | 4. |
| 5. | Total Additions | (13,482) | (9,347) | (11,978) | (8,305) | 1,504 | 1,043 | 5. |
| 6. | Total Rate Base | $ 382,380 | $ 375,001 | $ 175,303 | $ 173,498 | $ (207,077) | $ (201,503) | 6. |
| | Original Cost Impact | | | | | | | |
| 7. | APS Requested Rate of Return | | | | | | 8.87% | 7. |
| 8. | Required Operating Income [= Ln. 6 x Ln. 7] | | | | | | (17,874) | 8. |
| 9. | Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5) | | | | | | 1.6532 | 9. |
| 10. | Estimated Revenue Requirement Impact [= Ln. 8 x Ln. 9] | | | | | | $ (29,549) | 10. |
| | Fair Value Impact | | | | | | | |
| 11. | Adjusted Rate Base - Fair Value (FV) | | | | | | $ (201,503) | 11. |
| 12. | Requested Rate of Return with 1% FV Increment | | | | | | 6.47% | 12. |
| 13. | Required Operating Income [= Ln. 11 x Ln. 12] | | | | | | (13,037) | 13. |
| 14. | Incremental Fair Value Required Operating Income [= Ln. 13 - Ln. 8] | | | | | | 4,837 | 14. |
| 15. | Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5) | | | | | | 1.6532 | 15. |
| 16. | Estimated Fair Value Increment Revenue Requirement Impact [= Ln. 14 x Ln. 15] | | | | | | $ 7,996 | 16. |
| 17. | Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16] | | | | | | $ (21,553) | 17. |

# AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions - Summary

**Income Statement Impact Summary**

**(Includes Renewable, Fossil, Nuclear, Distribution, General, and Intangible Plant Additions)**

| Line No. | Description | Updated 9-20-2011 Post-Test Year Plant Additions | | 18-Month Average Post-Test Year Plant Additions | | Increase/(Decrease) From Updated as Filed Pro Forma | | Line No. |
|---|---|---|---|---|---|---|---|---|
| | | Total Co. (K) | ACC (L) | Total Co. (M) | ACC (N) | Total Co. (O) | ACC (P) | |
| | Electric Operating Revenues | | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - | 1. |
| 2. | Revenues from Surcharges | - | - | - | - | - | - | 2. |
| 3. | Other Electric Revenues | - | - | - | - | - | - | 3. |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - | 4. |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - | 5. |
| 6. | **Oper Rev Less Fuel & Purch Pwr Costs** | - | - | - | - | - | - | 6. |
| | Other Operating Expenses: | | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - | 7. |
| 8. | Maintenance | 1,935 | 1,869 | 1,935 | 1,869 | - | - | 8. |
| 9. | Subtotal | 1,935 | 1,869 | 1,935 | 1,869 | - | - | 9. |
| 10. | Depreciation and Amortization | 27,526 | 26,763 | 16,372 | 15,936 | (11,154) | (10,826) | 10. |
| 11. | Amortization of Gain | - | - | - | - | - | - | 11. |
| 12. | Administrative and General | - | - | - | - | - | - | 12. |
| 13. | Other Taxes | 10,027 | 9,784 | 7,479 | 7,303 | (2,548) | (2,481) | 13. |
| 14. | Total | 39,488 | 38,416 | 25,786 | 25,109 | (13,702) | (13,307) | 14. |
| 15. | Operating Income Before Income Tax | (39,488) | (38,416) | (25,786) | (25,109) | 13,702 | 13,307 | 15. |
| 16. | Interest Expense | 11,242 | 11,024 | 5,155 | 5,101 | (6,087) | (5,923) | 16. |
| 17. | Taxable Income | (50,730) | (49,440) | (30,941) | (30,210) | 19,789 | 19,230 | 17. |
| 18. | Current Income Tax Rate - 39.51% | (20,043) | (19,534) | (12,225) | (11,936) | 7,819 | 7,598 | 18. |
| 19. | Operating Income (line 15 minus line 18) | $ (19,445) | $ (18,882) | $ (13,561) | $ (13,173) | $ 5,883 | $ 5,709 | 19. |
| 20. | Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5) | | | | | | 1.6532 | 20. |
| 21. | Estimated Revenue Requirement Impact [= -Ln 19 x Ln. 20] | | | | | | $ (9,438) | 21. |

## AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions
**Rate Base Impact Summary**
**(Renewable Energy Resources)**

| | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| | | Updated 9-20-2011 Renewable Energy Resources Post-Test Year Plant Additions | | 18-Month Average Renewable Energy Resources Post-Test Year Plant Additions | | Increase/(Decrease) From As Filed Pro Forma | |
| *Line No.* | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| *1.* | Gross Utility Plant in Service | $ 260,765 | $ 251,899 | $ 114,730 | $ 110,829 | $ (146,035) | $ (141,070) |
| *2.* | Less: Accumulated Depreciation & Amort. | 5,593 | 5,403 | 1,481 | 1,431 | (4,112) | (3,972) |
| *3* | Net Utility Plant in Service | 255,172 | 246,496 | 113,249 | 109,399 | (141,923) | (137,098) |
| *4.* | Less: Total Deductions | 3,331 | 3,218 | 1,086 | 1,049 | (2,245) | (2,169) |
| *5.* | Total Additions | - | - | - | - | - | - |
| *6.* | Total Rate Base | $ 251,841 | $ 243,278 | $ 112,163 | $ 108,349 | $ (139,678) | $ (134,929) |

Data Source: APS Response to AECC Data Request No. 2.1.

## AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions
**Rate Base Impact Summary**
**(Fossil Generation Resources)**

| | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| | | Updated 9-20-2011 Fossil Generation Post-Test Year Plant Additions | | 18-Month Average Fossil Generation Post-Test Year Plant Additions | | Increase/(Decrease) From As Filed Pro Forma | |
| *Line No.* | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| *1.* | Gross Utility Plant in Service | $ 154,606 | $ 149,350 | $ 90,788 | $ 87,701 | $ (63,818) | $ (61,649) |
| *2.* | Less: Accumulated Depreciation & Amort. | 133,240 | 128,710 | 66,620 | 64,355 | (66,620) | (64,355) |
| *3* | Net Utility Plant in Service | 21,366 | 20,640 | 24,168 | 23,346 | 2,802 | 2,706 |
| *4.* | Less: Total Deductions | 12,583 | 12,155 | 6,292 | 6,078 | (6,292) | (6,078) |
| *5.* | **Total Additions** | - | - | - | - | - | - |
| *6.* | **Total Rate Base** | $ 8,783 | $ 8,485 | $ 17,877 | $ 17,269 | $ 9,094 | $ 8,784 |

Data Source: APS Response to AECC Data Request No. 2.2.

# AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions
## Rate Base Impact Summary
## (Nuclear Generation Resources)

| | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| | | Updated 9-20-2011 Nuclear Generation Post-Test Year Plant Additions | | 18-Month Average Nuclear Generation Post-Test Year Plant Additions | | Increase/(Decrease) From As Filed Pro Forma | |
| *Line No.* | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| *1.* | Gross Utility Plant in Service | $ 111,397 | $ 107,609 | $ 52,518 | $ 50,733 | $ (58,879) | $ (56,876) |
| *2.* | Less: Accumulated Depreciation & Amort. | 95,937 | 92,675 | 47,969 | 46,338 | (47,969) | (46,338) |
| *3* | Net Utility Plant in Service | 15,460 | 14,934 | 4,550 | 4,396 | (10,911) | (10,539) |
| *4.* | Less: Total Deductions | 29,329 | 28,331 | 14,665 | 14,166 | (14,665) | (14,166) |
| *5.* | **Total Additions** | - | - | - | - | - | - |
| *6.* | **Total Rate Base** | $ (13,869) | $ (13,397) | $ (10,115) | $ (9,770) | $ 3,754 | $ 3,627 |

Data Source: APS Response to AECC Data Request No. 2.3.

## AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions

**Rate Base Impact Summary**

**(Distribution, General and Intangible Plant)**

| | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| | | Updated 9-2011 Distribution and General and Intangible Post-Test Year Plant Additions | | 18-Month Average Distribution and General and Intangible Post-Test Year Plant Additions | | Increase/(Decrease) From As Filed Pro Forma | |
| *Line No.* | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| *1.* | Gross Utility Plant in Service | $ 422,758 | $ 413,898 | $ 204,182 | $ 199,913 | $ (218,576) | $ (213,985) |
| *2.* | Less: Accumulated Depreciation & Amort. | 269,239 | 263,596 | 134,620 | 131,798 | (134,620) | (131,798) |
| *3* | Net Utility Plant in Service | 153,519 | 150,302 | 69,563 | 68,115 | (83,957) | (82,187) |
| *4.* | Less: Total Deductions | 4,412 | 4,320 | 2,206 | 2,160 | (2,206) | (2,160) |
| *5.* | Total Additions | - | - | - | - | - | - |
| *6.* | Total Rate Base | $ 149,107 | $ 145,982 | $ 67,357 | $ 65,955 | $ (81,751) | $ (80,027) |

Data Source: APS Response to AECC Data Request No. 2.4.

# AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions
**Rate Base Impact Summary**
**(Cash Working Capital)**

| | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| | | Updated 9-20-2011 Cash Working Capital for Cost of Service Pro Formas[1] | | 18-Month Average Post-Test Year Plant Additions Cash Working Capital for Cost of Service Pro Formas[2] | | Increase/(Decrease) From As Filed Pro Forma | |
| *Line No.* | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| *1.* | Gross Utility Plant in Service | $ - | $ - | $ - | $ - | $ - | $ - |
| *2.* | Less: Accumulated Depreciation & Amort. | - | - | - | - | - | - |
| *3* | Net Utility Plant in Service | - | - | - | - | - | - |
| *4.* | Less: Total Deductions | - | - | - | - | - | - |
| *5.* | Total Additions | (13,482) | (9,347) | (11,978) | (8,305) | 1,504 | 1,043 |
| *6.* | Total Rate Base | $ (13,482) | $ (9,347) | $ (11,978) | $ (8,305) | $ 1,504 | $ 1,043 |

Data Sources: 1. APS Technical Conference, October 27, 2011 Workpapers.
2. APS Response to AECC Data Request No. 2.5.

# AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions
**Income Statement Impact Summary**
**(Renewable Energy Resources)**

| Line No. | Description | (A) Updated 9-20-2011 Renewable Energy Resources Post-Test Year Plant Additions: Total Co. | (B) ACC | (C) 18-Month Average Renewable Energy Resources Post-Test Year Plant Additions: Total Co. | (D) ACC | (E) Increase/(Decrease) From Updated as Filed Pro Forma: Total Co. | (F) ACC |
|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | | - | | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 8. | Maintenance | 1,935 | 1,869 | 1,935 | 1,869 | - | - |
| 9. | Subtotal | 1,935 | 1,869 | 1,935 | 1,869 | - | - |
| 10. | Depreciation and Amortization | 8,449 | 8,162 | 3,811 | 3,681 | (4,638) | (4,480) |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | 915 | 884 | 556 | 537 | (359) | (347) |
| 14. | Total | 11,299 | 10,915 | 6,302 | 6,088 | (4,997) | (4,827) |
| 15. | Operating Income Before Income Tax | (11,299) | (10,915) | (6,302) | (6,088) | 4,997 | 4,827 |
| 16. | Interest Expense | 7,404 | 7,152 | 3,298 | 3,186 | (4,106) | (3,966) |
| 17. | Taxable Income | (18,703) | (18,067) | (9,600) | (9,274) | 9,103 | 8,793 |
| 18. | Current Income Tax Rate - 39.51% | (7,390) | (7,138) | (3,793) | (3,664) | 3,597 | 3,474 |
| 19. | Operating Income (line 15 minus line 18) | $ (3,909) | $ (3,777) | $ (2,509) | $ (2,424) | $ 1,400 | $ 1,353 |

Data Source: APS Response to AECC Data Request No. 2.1.

# AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions

**Income Statement Impact Summary**
**(Fossil Generation Resources)**

| | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| | | Updated 9-20-2011 Fossil Generation Post-Test Year Plant Additions | | 18-Month Average Fossil Generation Post-Test Year Plant Additions | | Increase/(Decrease) From As Filed Pro Forma | |
| Line No. | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | | - | | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | - | - | - | - |
| 10. | Depreciation and Amortization | 4,201 | 4,058 | 2,467 | 2,383 | (1,734) | (1,675) |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | 940 | 908 | 552 | 533 | (388) | (375) |
| 14. | Total | 5,141 | 4,966 | 3,019 | 2,916 | (2,122) | (2,050) |
| 15. | Operating Income Before Income Tax | (5,141) | (4,966) | (3,019) | (2,916) | 2,122 | 2,050 |
| 16. | Interest Expense | 258 | 249 | 526 | 508 | 268 | 259 |
| 17. | Taxable Income | (5,399) | (5,215) | (3,545) | (3,424) | 1,854 | 1,791 |
| 18. | Current Income Tax Rate - 39.51% | (2,133) | (2,060) | (1,401) | (1,353) | 733 | 708 |
| 19. | Operating Income (line 15 minus line 18) | $ (3,008) | $ (2,906) | $ (1,618) | $ (1,563) | $ 1,389 | $ 1,342 |

Data Source: APS Response to AECC Data Request No. 2.2.

# AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions

**Income Statement Impact Summary**
**(Nuclear Generation Resources)**

| | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| | | Updated 9-20-2011 Nuclear Generation Post-Test Year Plant Additions | | 18-Month Average Nuclear Generation Post-Test Year Plant Additions | | Increase/(Decrease) From As Filed Pro Forma | |
| Line No. | Description | Total Co. | ACC | Total Co. | ACC | Total Co. | ACC |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | - | - | - | - |
| 10. | Depreciation and Amortization | 1,604 | 1,549 | 756 | 730 | (848) | (819) |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | 682 | 659 | 321 | 310 | (361) | (349) |
| 14. | Total | 2,286 | 2,208 | 1,077 | 1,040 | (1,209) | (1,168) |
| 15. | Operating Income Before Income Tax | (2,286) | (2,208) | (1,077) | (1,040) | 1,209 | 1,168 |
| 16. | Interest Expense | (408) | (394) | (297) | (287) | 111 | 107 |
| 17. | Taxable Income | (1,878) | (1,814) | (780) | (753) | 1,098 | 1,061 |
| 18. | Current Income Tax Rate - 39.51% | (742) | (717) | (308) | (298) | 434 | 419 |
| 19. | Operating Income (line 15 minus line 18) | $ (1,544) | $ (1,491) | $ (769) | $ (742) | $ 775 | $ 749 |

Data Source: APS Response to AECC Data Request No. 2.3.

# AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions
**Income Statement Impact Summary**
**(Distribution, General and Intangible Plant)**

| Line No. | Description | (A) Updated 9-20-2011 Distribution-General-Intangible Post-Test Year Plant Additions: Total Co. | (B) ACC | (C) 18-Month Average Distribution and General and Intangible Post-Test Year Plant Additions: Total Co. | (D) ACC | (E) Increase/(Decrease) From As Filed Pro Forma: Total Co. | (F) ACC |
|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | | - | | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | - | - | - | - |
| 10. | Depreciation and Amortization | 13,272 | 12,994 | 9,338 | 9,142 | (3,934) | (3,852) |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | 7,490 | 7,333 | 6,050 | 5,923 | (1,440) | (1,410) |
| 14. | Total | 20,762 | 20,327 | 15,388 | 15,065 | (5,374) | (5,262) |
| 15. | Operating Income Before Income Tax | (20,762) | (20,327) | (15,388) | (15,065) | 5,374 | 5,262 |
| 16. | Interest Expense | 4,384 | 4,292 | 1,980 | 1,939 | (2,404) | (2,353) |
| 17. | Taxable Income | (25,146) | (24,619) | (17,368) | (17,004) | 7,778 | 7,615 |
| 18. | Current Income Tax Rate - 39.51% | (9,935) | (9,727) | (6,862) | (6,718) | 3,073 | 3,009 |
| 19. | Operating Income (line 15 minus line 18) | $ (10,827) | $ (10,600) | $ (8,526) | $ (8,347) | $ 2,301 | $ 2,253 |

Data Source: APS Response to AECC Data Request No. 2.4.

# AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions
**Income Statement Impact Summary**
**(Cash Working Capital)**

| Line No. | Description | (A) Updated 9-20-2011 Cash Working Capital for Cost of Service Pro Formas[1] Total Co. | (B) ACC | (C) 18-Month Average Post-Test Year Plant Additions Cash Working Capital for Cost of Service Pro Formas[2] Total Co. | (D) ACC | (E) Increase/(Decrease) From As Filed Pro Forma Total Co. | (F) ACC |
|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | | - | | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | - | - | - | - |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | - | - | - | - | - | - |
| 15. | Operating Income Before Income Tax | - | - | - | - | - | - |
| 16. | Interest Expense | (396) | (275) | (352) | (244) | 44 | 30 |
| 17. | Taxable Income | 396 | 275 | 352 | 244 | (44) | (30) |
| 18. | Current Income Tax Rate - 39.51% | 156 | 109 | 139 | 97 | (17) | (12) |
| 19. | Operating Income (line 15 minus line 18) | $ (156) | $ (109) | $ (139) | $ (97) | $ 17 | $ 12 |

Data Sources: 1. APS Technical Conference, October 27, 2011 Workpapers.
2. APS Response to AECC Data Request No. 2.5.

KCH-3

# AECC Sales Growth Adjustment
**Income Statement Impact**
**(Thousands of Dollars)**

**Pro Forma Adjustment: Mar. 2012 Sales Growth**
AECC Adjustment to APS Test Year Operations to Adjust Revenue and Fuel and Purchased Power Costs to March, 2012 Consumption.

| Line No. | Description | AECC | Amount | Source |
|---|---|---|---|---|
| 1. | **REVENUES** | | | |
| 2. | Operating Revenue | | 34,852 | See Page 2 |
| 3. | Pro Forma Additional Mar. 2012 Retail Consumption (MWh) | 341,921 | | = Ln. 9 |
| 4. | **ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)** | | | |
| 5. | Normalized Fuel and Purchased Power Costs (¢/kWh) | 3.2071 | | APS Technical Conference, October 27, 2011 Workpapers. |
| 6. | **ADJUSTED TEST YEAR RETAIL SALES (MWh)** | | | |
| 7. | Adjusted Test Year Retail Sales (MWh) | 27,833,756 | | APS Technical Conference, October 27, 2011 Workpapers. |
| 8. | Pro Forma Adjustments to Adjusted Test Year Retail Sales | | | |
| 9. | To Adjust to Mar. 2012 Consumption (MWh) | 341,921 | | = Ln. 10 - Ln. 7 |
| 10. | Mar. 2012 Retail Sales (MWh) | 28,175,677 | | APS Response to Staff Data Request No. 3.11 |
| 11. | Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 7 x Line 11) | | $ 10,966 | = [Ln. 5 x Ln. 9] ÷ 1,000 |
| 12. | **Operating Income (before income tax)** | | $ 23,886 | = Ln. 2 - Ln. 11 |
| 13. | Current Income Tax Rate - 39.51% | | 9,437 | =39.51% x Ln. 12 |
| 14. | **Operating Income After Tax** | | $ 14,449 | = Ln. 12 - Ln. 13 |
| 15. | **Gross Revenue Conversion Factor** | | 1.6532 | APS SFR Schedule C-3, Ln. 5 |
| 16. | **Estimated Revenue Requirement Impact** | | $ (23,887) | = -Ln 14 x Ln. 17 |

## Derivation of Additional Revenue from March 2012 Sales Growth

| Line No. | (a) | (b) 2010 Test Year Retail Sales[1] (MWh) | (c) 2010 Normal Weather Retail Sales Adjustment[2] (MWh) | (d) 2010 Customer Annualization Retail Sales Adjustment[2] (MWh) | (e) = (a) + (b) + (c) 2010 Adjusted Test Year Retail Sales (MWh) | (f) Twelve Months Ending Mar. 2012 Retail Sales[3] (MWh) | (g) = (f) - (e) Twelve Months Ending Mar. 2012 Sales Growth (MWh) | (h) Sch. H-2 Avg Present Revenue[4] ($/kWh) | (i) = (g) x (h) Mar. 2012 Sales Growth Revenue ($000) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential | 13,035,500 | 39,327 | 25,458 | 13,100,285 | 13,234,660 | 134,375 | $ 0.11224 | $ 15,082 |
| 2 | Commercial | 12,361,364 | 77,422 | (13,594) | 12,425,192 | | | | |
| 3 | Industrial | 2,149,128 | 0 | 0 | 2,149,128 | | | | |
| 4 | C&I Total | 14,510,492 | 77,422 | (13,594) | 14,574,320 | 14,777,016 | 202,696 | $ 0.09514 | $ 19,285 |
| 5 | Irrigation | 20,955 | 0 | (3,379) | 17,576 | 21,639 | 4,063 | $ 0.08512 | $ 346 |
| 6 | Hwy lighting & other pub. authority | 142,516 | 0 | (941) | 141,575 | 142,362 | 787 | $ 0.17717 | $ 139 |
| 7 | Total Retail Sales | 27,709,463 | 116,749 | 7,544 | 27,833,756 | 28,175,677 | 341,921 | | $\boxed{\$\ 34{,}852}$ |

Data Sources:
1. APS Direct Filing Workpaper PME-WP04 2010 TY Native Load Sales
2. APS Direct Filing Workpaper CAM_WP08 Revenue Proforma Summary
3. APS Response to Staff Data Request No. 3.11 [Forecast Data 2011-2015]
4. Average present unit revenue derived from APS SFR Schedule H-2

KCH-4

# AECC ADJUSTMENT TO SOLAR GENERATION POST-TEST YEAR PLANT ADDITIONS TO REMOVE COST ABOVE MARKET COST OF COMPARABLE CONVENTIONAL GENERATION FROM BASE RATES

**ACC JURISDICTION**

**(Thousands of Dollars)**

| Line No. | Description | AECC Solar Original Cost | Adjustment Solar Original Cost | AECC Solar @ 36% Original Cost | Line No. |
|---|---|---|---|---|---|
| *1.* | Adjusted Rate Base | $ 108,349 | $ (68,970) | $ 39,379 | *1.* |
| *2.* | Adjusted Operating Income | (2,424) | 1,543 | (881) | *2.* |
| *3.* | Current Rate of Return | -2.24% | -2.24% | -2.24% | *3.* |
| *4.* | Required Operating Income | 9,611 | (6,118) | 3,493 | *4.* |
| *5.* | Required Rate of Return | 8.87% | 8.87% | 8.87% | *5.* |
| *6.* | Adjusted Operating Income Deficiency | 12,035 | (7,661) | 4,374 | *6.* |
| *7.* | Gross Revenue Conversion Factor | 1.6532 | 1.6532 | 1.6532 | *7.* |
| *8.* | Requested Increase in Base Revenue Requirements | $ 19,896 | $ (12,665) | $ 7,230 | *8.* |
| | Fair Value Impact | | | | |
| *9.* | Estimated Fair Value Increment Revenue Requirement Impact [See Attachment KCH-4, p. 2 of 4] | | 2,737 | | *9.* |
| *10.* | Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16] | | $ (9,928) | | *10.* |

**AECC ADJUSTMENT TO SOLAR GENERATION POST-TEST YEAR PLANT ADDITIONS TO REMOVE COST ABOVE MARKET COST OF COMPARABLE CONVENTIONAL GENERATION FROM BASE RATES**

**Rate Base Impact**
**(Thousands of Dollars)**

| | | AECC18-Month Average Renewable Energy Resources Post-Test Year Plant Additions | | Allowable Portion of 18-Month Average Renewable Energy Resources Post-Test Year Plant Additions Below Market Cost of Comparable Conventional Generation | | AECC Recommended Adjustment for Renewable Generation Costs Above the Market Cost oF Comparable Conventional Generation | | |
|---|---|---|---|---|---|---|---|---|
| *Line No.* | Description (A) | Total Co. (E) | ACC (I) | Total Co. (E) | ACC (I) | Total Co. (E) | ACC (I) | *Line No.* |
| *1.* | Gross Utility Plant in Service | $ 114,730 | $ 110,829 | $ 41,698 | $ 40,281 | $ (73,032) | $ (70,549) | *1.* |
| *2.* | Less: Accumulated Depreciation & Amort. | 1,481 | 1,431 | 538 | 520 | (943) | (911) | *2.* |
| *3* | Net Utility Plant in Service | 113,249 | 109,399 | 41,160 | 39,761 | (72,089) | (69,638) | *3* |
| *4.* | Less: Total Deductions | 1,086 | 1,049 | 395 | 381 | (691) | (668) | *4.* |
| *5.* | Total Additions | - | - | - | - | - | - | *5.* |
| *6.* | Total Rate Base | $ 112,163 | $ 108,349 | $ 40,765 | $ 39,379 | $ (71,398) | $ (68,970) | *6.* |
| | Original Cost Impact | | | | | | | |
| *7.* | APS Requested Rate of Return | | | | | | 8.87% | *7.* |
| *8.* | Required Operating Income [= Ln. 6 x Ln. 7] | | | | | | (6,118) | *8.* |
| *9.* | Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5) | | | | | | 1.6532 | *9.* |
| *10.* | Estimated Revenue Requirement Impact [= Ln. 8 x Ln. 9] | | | | | | $ (10,114) | *10.* |
| | Fair Value Impact | | | | | | | |
| *11.* | Adjusted Rate Base - Fair Value (FV) | | | | | | $ (68,970) | *11.* |
| *12.* | Requested Rate of Return with 1% FV Increment | | | | | | 6.47% | *12.* |
| *13.* | Required Operating Income [= Ln. 11 x Ln. 12] | | | | | | (4,462) | *13.* |
| *14.* | Incremental Fair Value Required Operating Income [= Ln. 13 - Ln. 8] | | | | | | 1,655 | *14.* |
| *15.* | Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5) | | | | | | 1.6532 | *15.* |
| *16.* | Estimated Fair Value Increment Revenue Requirement Impact [= Ln. 14 x Ln. 15] | | | | | | $ 2,737 | *16.* |
| *17.* | Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16] | | | | | | $ (7,377) | *17.* |

# AECC ADJUSTMENT TO SOLAR GENERATION POST-TEST YEAR PLANT ADDITIONS TO REMOVE COST ABOVE MARKET COST OF COMPARABLE CONVENTIONAL GENERATION FROM BASE RATES

**Income Statement Impact**
**(Thousands of Dollars)**

| Line No. | Description | AECC18-Month Average Renewable Energy Resources Post-Test Year Plant Additions | | Allowable Portion of 18-Month Average Renewable Energy Resources Post-Test Year Plant Additions Below Market Cost of Comparable Conventional Generation | | AECC Recommended Adjustment for Renewable Generation Costs Above the Market Cost of Comparable Conventional Generation | | Line No. |
|---|---|---|---|---|---|---|---|---|
| | | Total Co. (E) | ACC (I) | Total Co. (E) | ACC (I) | Total Co. (E) | ACC (I) | |
| | Electric Operating Revenues | | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - | 1. |
| 2. | Revenues from Surcharges | - | - | - | - | - | - | 2. |
| 3. | Other Electric Revenues | - | - | - | - | - | - | 3. |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - | 4. |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - | 5. |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - | 6. |
| | Other Operating Expenses: | | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - | 7. |
| 8. | Maintenance | 1,935 | 1,869 | 703 | 679 | (1,232) | (1,190) | 8. |
| 9. | Subtotal | 1,935 | 1,869 | 703 | 679 | (1,232) | (1,190) | 9. |
| 10. | Depreciation and Amortization | 3,811 | 3,681 | 1,385 | 1,338 | (2,426) | (2,343) | 10. |
| 11. | Amortization of Gain | - | - | - | - | - | - | 11. |
| 12. | Administrative and General | - | - | - | - | - | - | 12. |
| 13. | Other Taxes | 556 | 537 | 202 | 195 | (354) | (342) | 13. |
| 14. | Total | 6,302 | 6,088 | 2,290 | 2,213 | (4,012) | (3,875) | 14. |
| 15. | Operating Income Before Income Tax | (6,302) | (6,088) | (2,290) | (2,213) | 4,012 | 3,875 | 15. |
| 16. | Interest Expense | 3,298 | 3,186 | 1,199 | 1,158 | (2,099) | (2,028) | 16. |
| 17. | Taxable Income | (9,600) | (9,274) | (3,489) | (3,370) | 6,111 | 5,903 | 17. |
| 18. | Current Income Tax Rate - 39.51% | (3,793) | (3,664) | (1,379) | (1,332) | 2,414 | 2,332 | 18. |
| 19. | Operating Income (line 15 minus line 18) | $ (2,509) | $ (2,424) | $ (911) | $ (881) | $ 1,598 | $ 1,543 | 19. |
| 20. | Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5) | | | | | | 1.6532 | 20. |
| 21. | Estimated Revenue Requirement Impact [= -Ln 19 x Ln. 20] | | | | | | $ (2,551) | 21. |

## Derivation of AECC's Recommended Percentage of Renewable Generation Allowed to be Transferred from the RES to Base Rates

| | (a) | (b) | (c) | (d) = (b) ÷ (c) | |
|---|---|---|---|---|---|
| Line No. | Description | NPV $M | NPV GWh | NPV $/MWh | Source |
| 1 | Combined 35 Year (Bid Term) NPV of AZ Sun Solar Projects @ 8.01% | [redacted] | [redacted] | [redacted] | APS CONFIDENTIAL Response to AECC DR No. 4.1-2(a) |
| | | Nominal $M | Nominal GWh | Nominal $/MWh | |
| 2 | APS Avoided Cost for Calendar Year 2012 | [redacted] | [redacted] | [redacted] | APS CONFIDENTIAL Response to AECC DR No. 4.1-2(a) |
| 3 | Percent AZ Sun Projects Bid Above APS Avoided Cost | | | [redacted] | = Ln 1 ÷ Ln. 2 |
| 4 | Percent of AZ Sun Projects below AC | | | 36% | = Ln 2 ÷ Ln. 1 |
| 5 | Percent of AZ Sun Projects Above AC | | | 64% | = 100% - Ln. 4 |

**KCH-5**

AECC ADJUSTMENT TO SYSTEM BENEFIT CHARGE EXPENSE
TEST YEAR ENDING 12/31/2010

| *Line No.* | Description | Total Company | ACC Jurisdiction | Allocator |
|---|---|---|---|---|
| *1.* | Operating Expenses (Actual Test Year 2010) | | | |
| *2.* | DSM | 10,000,000 | 10,000,000 | 1.0000 |
| *3.* | Four Corners & Navajo Coal Reclamation | 1,722,817 | 1,680,982 | 0.9757 |
| *4.* | ISFSI | 5,233,000 | 5,105,928 | 0.9757 |
| *5.* | Palo Verde Decommissioning | 19,198,000 | 18,731,817 | 0.9757 |
| *6.* | E-3 & E-4 Discounts | 10,674,321 | 10,674,321 | 1.0000 |
| *7.* | Total Operating Expenses | 46,828,138 | 46,193,047 | |
| *8.* | Operating Expenses (APS Proforma) | | | |
| *9.* | ISFSI Expense Update - APS Adjustment # 10 (Sch C-2, p. 4, line 5) | (4,236,000) | (4,133,138) | 0.9757 |
| *10.* | Palo Verde Decommissioning - APS Adjustment #10 (Sch. C-2, p. 4, line 10) | (2,947,000) | (2,875,438) | 0.9757 |
| *11.* | Coal Reclamation - APS Adjustment #20 (Sch C-2, p. 7, line 5) | 6,216,000 | 6,065,057 | 0.9757 |
| *12.* | Total Operating Expenses | (967,000) | (943,518) | |
| *13.* | APS Proposed Total System Benefits Expenses | 45,861,138 | 45,249,529 | |
| *14.* | AECC Adjustment to APS Proforma System Benefit Operating Expense: | (8,920,975) | (8,704,348) | 0.9757 |
| *15.* | AECC Recommended Total System Benefits Expenses | 36,940,163 | 36,545,181 | |

Data Sources: APS Response to Staff Inf. 2.1, Attachment APS14996 and JCL_WP22 IS

AECC SYSTEM BENEFITS CHARGE CALCULATION
TEST YEAR ENDING 12/31/2010

| *Line No.* | Description | | |
|---|---|---|---|
| *1.* | APS Proposed System Benefits Revenue Requirement | $ | 45,249,529 |
| *2.* | Energy Consumption @ Customer Level (kWh) | | 27,448,414,000 |
| *3.* | APS Proposed System Benefits Unit Cost ($/kWh) | | $0.00165 |
| | | | |
| *4.* | AECC Recommended System Benefits Revenue Requirement | $ | 36,545,181 |
| *5.* | Energy Consumption @ Customer Level (kWh) | | 27,448,414,000 |
| *6.* | AECC Recommended System Benefits Unit Cost ($/kWh) | | $0.00133 |
| *7.* | AECC Adjustment to APS Proposed System Benefit Unit Cost ($/kWh) | | ($0.00032) |

Data Source: APS Response to Staff 24.7, Attachment APS14933

# BEFORE THE ARIZONA CORPORATION COMMISSION

| | |
|---|---|
| In the Matter of the Application of Arizona )<br>Public Service Company for a Hearing to )<br>Determine the Fair Value of the Utility )<br>Property of the Company for Ratemaking )<br>Purposes, to Fix a Just and Reasonable )<br>Rate of Return Thereon, to Approve Rate )<br>Schedules Designed to Develop Such Return) | Docket No. E-01345A-11-0224 |

## Direct Testimony of Kevin C. Higgins

**on behalf of**

**Freeport-McMoRan Copper & Gold Inc. and**

**Arizonans for Electric Choice & Competition**

**Cost of Service / Rate Design**

**December 2, 2011**

## DIRECT TESTIMONY OF KEVIN C. HIGGINS

## TABLE OF CONTENTS

## DIRECT TESTIMONY OF KEVIN C. HIGGINS

**INTRODUCTION**

**Q. Please state your name and business address.**

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

**Q. Are you the same Kevin C. Higgins who previously filed testimony on the subject of revenue requirements in this proceeding on behalf of Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC")?[1]**

A. Yes, I am. My qualifications are presented in Appendix A attached to that direct testimony.

**OVERVIEW AND CONCLUSIONS**

**Q. What is the purpose of your testimony in this cost-of-service and rate design phase of the proceeding?**

A. My testimony addresses APS's proposed rate spread, rate design, and cost of service analysis.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

**Q. What are the primary conclusions and recommendations presented in your testimony?**

A. (1) I recommend that APS's cost of service study be adopted by the Commission. The Average and Excess Demand method employed by APS to allocate production plant costs fully meets the Commission's stated objectives in Decision No. 69663. Further, APS's allocation of energy costs based on customer class hourly load shapes and their relationship to hourly energy prices is fundamentally reasonable. This approach properly aligns cost responsibility with cost causation, and therefore is inherently equitable.

(2) APS's proposed spread of its rate increase focuses exclusively on base rates. This is not the proper basis for rate spread determination because the sizable credit in the Power Supply Adjustor ("PSA") is being reset to near zero when new rates take effect. By itself, this PSA Reset has the effect of increasing rates (on average) over 5 percent. The impact of the PSA Reset is even greater on industrial customers – around 8 percent. This impact must be added to the base rate increase and taken into account in determining the equitable spread of rates across customer classes.

(3) APS's proposed rate spread largely ignores cost of service ratemaking principles, while greatly expanding the very sizable subsidy that General Service customers pay to Residential customers to $124 million per year. I recommend that the Company's rate spread be rejected in favor of an approach that balances the ratemaking objectives of adherence to cost-of-service principles and gradualism. Specifically, I recommend a five-step approach that: (a) moves

Residential rates halfway to cost-of-service; (b) caps the rate impact on all classes to no more than 5 percentage points above the average percentage increase (taking account of the PSA Reset); (c) sets rates for Rate Schedules E-34 and E-35 equal to cost-of-service; (d) funds the residential subsidy through an equal percentage increase on the subsidy-paying classes; and (e) smoothes out the rate impact within the E-32 customer group.

(4) I recommend that APS's proposed Interruptible Rate Rider be approved with two modifications: (a) changing the basis of the proposed credit paid to participating customers from "50% demand / 50% energy" as proposed by APS to "100% demand," and (b) including in the Rider a multiyear schedule of capacity rates, rather than a single rate that will stand until the next general rate case.

(5) I recommend that Experimental Rate Rider AG-1 be approved by the Commission, but the requirement to pay a Reserve Capacity Charge should be removed. I also recommend that Experimental Rate Rider AG-1 should not be viewed as a substitute for reinstating full direct access service in Arizona.

(6) I recommend approval of APS's proposal to change the rate design of Rate Schedule 32-L by removing the first tier energy charge for this rate schedule, modifying the remaining energy charge to reflect the average energy cost per kWh, and revising the demand charge to include the implicit demand-related costs that are currently recovered through the first tier energy charge.

(7) APS's proposed rate design for Rate Schedules E-34 and E-35 should be rejected, as it fails to properly take account of the implications of the PSA Reset, and would unduly increase the net energy charge in these rate schedules to

the detriment of the higher-load-factor customers served on them. Instead, I recommend that the energy charge for these two rate schedules be set equal to the current base energy rate *minus* the amount of the current credit in the Forward Component of the PSA. As fuel costs are declining, the energy charges for E-34 and E-35 customers should not be increased above this level. The revenues to support this rate design would not come from customers on other rate schedules, but from increasing the E-34 and E-35 demand charges to the level sufficient to recover the targeted revenue requirement for these two rate schedules.

## COST OF SERVICE

**Q. What is the purpose of cost-of-service analysis?**

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

**Q. What is the role of cost-of-service analysis in setting rates?**

A. Each of the three steps above has an important role in the ratemaking process. If rates are unbundled by function, as they are in Arizona, then separating the utility's costs by function is important in determining which costs are generation-related, transmission-related, and distribution-related.

The classification of costs is critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes is important for determining revenue apportionment across customer classes, also called "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. For these reasons, the results of the class cost-of-service analysis should be given very strong weighting in guiding the proper revenue apportionment.

**Q. What approach has APS used for allocating generation plant costs between APS retail customers and FERC-jurisdictional customers?**

A. As explained in the direct testimony of APS witness Zachary J. Fryer, APS uses the 4-Coincident Peaks ("4-CP") method for allocating generation plant costs between its state and federal jurisdictional loads. The 4-CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when APS's production capacity requirements are determined.

**Q. In your opinion, is the 4-CP method appropriate for allocating APS's jurisdictional generation plant costs?**

A. Yes, it is. APS's maximum system demands are driven by summer usage. Given the characteristics of APS's system, the 4-CP method properly aligns the allocation of the Company's fixed costs with cost causation. As noted by Mr. Fryer, the 4-CP method is used by APS in its cases before FERC.

**Q. Does APS also use the 4-CP method for allocating generation plant costs across its retail customer classes in this case?**

A. No. APS uses the Average and Excess Demand method for that purpose. This method was used in APS's previous rate case and was adopted in response to the directives and guidance from the Commission in Decision No. 69633 in Docket No. E-01345A-05-0816. [Decision at 70-71]

**Q. Do you agree with APS's use of the Average and Excess Demand method for allocating the cost of production plant cost among customer classes?**

A. Yes, I do. The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods" and fully meets the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[2]

**Q. How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?**

---

[2] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's excess demand, where excess demand is measured as the difference between each class's individual peak demand[3] and its average demand. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

**Q. Is the Average and Excess Demand method used in any neighboring jurisdictions?**

A. Yes. This method is utilized by the Salt River Project, Public Service Company of Colorado, and El Paso Electric Company in Texas.

**Q. How does APS allocate energy costs across customer classes?**

A. Consistent with its filing in its previous general rate case, APS allocates energy costs based on customer class hourly load shapes and their relationship to hourly energy prices, which produces a weighted energy cost for each class. This approach is a great improvement over the method that had been used for allocating energy costs prior to the last APS rate case; prior to that case, each kilowatt-hour was assigned exactly the same average cost irrespective of whether it occurred during the high-cost, summer on-peak periods, or a lower-cost, off-peak periods.

**Q. Do you support APS's use of a weighted energy cost for each customer class based on the class's hourly load shape?**

[3] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

A. Yes. This approach properly aligns cost responsibility with cost causation, and therefore is inherently equitable.

**Q. What is your overall recommendation concerning APS's cost-of-service methodology in this proceeding?**

A. For the reasons discussed above, I recommend that the method used by APS for production cost-of-service be approved by the Commission.

**Q. Did you conduct any cost-of-service analysis in addition to what APS has presented?**

A. Yes. APS's cost-of-service analysis presents the revenue deficiency for each customer class at an equalized rate of return for <u>base</u> rates. While this is a useful piece of information, it only tells part of the story: APS's sole focus on base rates ignores the implications of resetting the Forward Component of the PSA, which is currently a credit, to zero. The PSA Reset will occur when new base rates go into effect. To understand more fully the implications of APS's cost-of-service study results, it is also necessary to indentify each customer class's revenue deficiency and rate impacts *after* taking account of the PSA credits in current rates and the knowledge that the PSA will be reset. Such an analysis does not undo the APS study, but simply provides more information to present a more complete picture.

In Attachment KCH-6, page 1, I present class returns and revenue deficiencies based on APS's cost-of-service study for base rates only. On page 2 of this attachment, I present the class revenue deficiencies after taking account of the PSA Credit Reset that will accompany rate implementation. The results of this analysis are summarized in Table KCH-2, below.[4]

**Table KCH-2**

**APS Cost-of-Service Results**
Percentage rate change required to bring each class to cost-of-service at APS's proposed revenue requirement

| Class | Required Base Rate Change | Rate Change Inc. Reset of PSA Credit |
|---|---|---|
| Residential | 12.40% | 17.66% |
| General Service | (6.80)% | (1.27)% |
| E-20 | 24.60% | 31.18% |
| E-32 (total) | (8.13)% | (3.03)% |
| E-32 TOU | (11.13)% | (5.07)% |
| E-30, E-32XS, S | (11.35)% | (7.35)% |
| E-32M | (6.69)% | (1.25)% |
| E-32L | (4.09)% | 2.46% |
| E-34 | (0.25)% | 7.47% |
| E-35 | 0.95% | 9.69% |
| Water Pumping | 9.18% | 16.47% |
| Street Lighting | 11.19% | 15.33% |
| Dusk-to-Dawn | (2.52)% | (0.98)% |
| Total | 3.33% | 8.77% |

**Q. Please explain the "Required Base Rate Change" column in Table KCH-2.**

A. This column shows the percentage change in base rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding. The percentages in this column focus exclusively on changes in base rates; thus, the rate impact in this column ignores the fact that customers currently receive a substantial credit through the PSA Adjustor, the forward-looking component of

[4] This table is enumerated KCH-2 as Table KCH-1 is incorporated in my revenue requirement testimony.

which will be reset to zero. In other words, the change in base rates being shown does not reflect the impact experienced by customers from the loss of the PSA credit.

**Q. Please explain the "Rate Change Inclusive of Reset of PSA Credit" column in Table KCH-2.**

A. This column shows the percentage change in rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding – after taking into consideration that customers are currently receiving a PSA credit equal to $0.005658/kWh – and that the forward-looking component of the PSA will be reset to zero when the new Base Fuel Rate takes effect.[5] The loss of this credit means that the net rate impact on customers from APS's proposed revenue requirement is significantly larger than the base rate increase viewed in isolation.

**Q. After taking account of the PSA credit being reset to zero, what is the net retail rate impact on APS customers from APS's proposed base rate increase?**

A. As shown in Attachment KCH-6, page 2, column (h) the net retail rate increase from APS's proposed base rate increase (as filed) and the resetting of the PSA credit to zero is $239 million, or 8.77% on an overall basis.

**Q. But isn't part of APS's proposed base rate increase comprised of $44.9 million in solar generation plant additions costs that would be recovered**

[5] The current PSA credit of $0.005658/kWh is comprised of a Forward Component of $0.002642/kWh and an Historical Component of $0.003016/kWh. In its rate impact analysis, APS uses going-forward estimates of the PSA credit equal to $0.000014 for the Forward Component (effectively zero) and 0.000461/kWh for the Historical Component. Source: APS response to Staff 3.065, Attachment CAM-14, p. 3.

**from customers anyway through the RES Tariff if they were not shifted into base rates as proposed by APS?**

A. Yes. But in ascertaining the rate impact faced by customers from bringing (all or part of) the solar plant additions costs into base rates, it is important to distinguish between those solar plant additions costs that are eligible (or approved) for *future* recovery through the RES Tariff and the recovery of these solar generation costs actually in current RES rates. Most of the solar plant additions costs at issue in this case are not yet being recovered through the RES Tariff – indeed only about $14.6 million of the $44.9 million in solar generation plant additions costs that APS is proposing for inclusion in base rates is being recovered through the 2011 RES Adjustor.[6] Thus, the recovery of the remaining $30.3 million in solar plant addition costs represents a net rate increase for customers – irrespective of whether these costs are recovered through the RES Tariff or recovered in base rates (or some combination of the two, as proposed in my direct testimony addressing revenue requirements).

**Q. After taking account of the PSA credit being reset, and also taking account of the solar generation plant additions costs that are currently being recovered through the 2011 RES Adjustor, what is the net retail rate impact on APS customers from APS's proposed base rate increase relative to retail rates in effect at the end of 2011?**

A. After taking into account that the 2011 RES Adjustor is currently recovering about $14.6 million of the $44.9 million in solar generation plant additions costs, the net retail rate increase from APS's proposed base rate increase

[6] Source: APS Response to AECC Data Request No. 3.1(f).

(as filed) and the resetting of the PSA credit to zero is $224.4 million, or 8.19%[7] on an overall basis, relative to retail rates in effect at the end of 2011. This number is derived from subtracting the $14.6 million current RES recovery from the $239 million rate impact identified just above.

**Q. But will a greater proportion of solar generation plant additions costs be recovered in the 2012 RES Adjustor?**

A. That is possible. APS has requested approval from the Commission to increase the 2012 RES Adjustor and part of that increase would be used to fund solar generation plant additions costs projected to be incurred in 2012. As of the date of this testimony, the Commission had not acted on this request.

To the extent that the Commission approves recovery of incremental solar plant additions costs through the 2012 RES Adjustor, then those costs would start to be recovered prior to the rate-effective period in this general rate case. As such, those costs would be removed from RES Adjustor if (and to the extent) that solar plant additions costs were approved for recovery in base rates as part of this case.

**Q. Given that the net impact on customers from moving RES-eligible costs into base rates is uncertain and something of a moving target, what revenue requirement increase did you utilize as a baseline in developing a rate spread proposal?**

A. In my rate spread proposal presented below, I use a baseline revenue requirement increase of $239 million, comprised of the sum of APS's proposed

[7] % Increase = Net Retail Increase ÷ [Present Base Rev. + PSA Reset Rev. + RES Solar Rev.]
% Increase = $224.4 ÷ [$2,868.9 + ($143.5) + $14.6] = 8.19%

base rate increase and PSA Reset, as discussed above. From a customer perspective, this baseline represents the "worst case scenario." Of course, the final rate increase in this case should be less than this: a number of parties, including AECC, have recommended significant reductions to APS's rate increase proposal. In addition, as I noted above, to the extent that rates are increased to recover incremental solar generation costs *prior* to the rate-effective period in this case, then some portion of any base rate increase associated with solar generation plant additions can be offset through a reduction in the RES Adjustor.

As discussed below, although the principles in my rate spread proposal are illustrated using the $239 million increase, these principles can be applied to any smaller revenue requirement increase that is adopted.

## RATE SPREAD

**Q. What general guidelines should be employed in spreading any change in rates?**

A. In determining rate spread, or revenue apportionment, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

**Q. What has APS proposed with respect to rate spread?**

A. APS's proposed rate spread is discussed by APS witness Charles A. Miessner and is presented in APS Schedule H-2 and is restated in Table KCH-3, below, along with APS's cost-of-service results. The rate changes shown in Table KCH-3 are for *base rates only*, consistent with APS's presentation in Schedule H-2. I also present in Table KCH-4 the combined rate impacts of APS's proposed base rate change and the PSA Rest, which, as I have stated, provides greater insight than viewing base rate changes in isolation, and therefore is a better tool for determining a reasonable rate spread.

**Table KCH-3**

**Comparison of APS Cost-of-Service Results to APS Proposed Rate Change**
**Base Rates Only**

| Class | Base Rate Change per APS COS | APS Proposed Base Rate Change | Difference Between Proposed Rate & Cost |
|---|---|---|---|
| Residential | 12.40% | 3.95% | (8.45)% |
| General Service | (6.80)% | 2.64% | 9.44% |
| E-20 | 24.60% | 3.89% | (20.72)% |
| E-32 (total) | (8.13)% | 2.53% | 10.66% |
| E-32 TOU | (11.13)% | 2.60% | 13.73% |
| E-30, E-32XS, S | (11.35)% | 2.22% | 13.57% |
| E-32M | (6.69)% | 2.77% | 9.46% |
| E-32L | (4.09)% | 2.77% | 6.87% |
| E-34 | (0.25)% | 3.07% | 3.32% |
| E-35 | 0.95% | 3.37% | 2.42% |
| Water Pumping | 9.18% | 3.62% | (5.56)% |
| Outdoor Lighting | 11.19% | 3.62% | (7.57)% |
| Dusk-to-Dawn | (2.52)% | 2.94% | 5.46% |
| Total | 3.33% | 3.33% | 0.00% |

**Table KCH-4**

**Comparison of APS Cost-of-Service Results to APS Proposed Rate Change**
**Combined Impact of Base Rates and PSA Reset**

| Class | Rate Change per APS COS | APS Proposed Rate Change | Difference Between Proposed Rate & Cost |
|---|---|---|---|
| Residential | 17.66% | 8.82% | (8.84)% |
| General Service | (1.27)% | 8.73% | 10.00% |
| E-20 | 31.18% | 9.37% | (21.81)% |
| E-32 (total) | (3.03)% | 8.23% | 11.25% |
| GS TOU | (5.07)% | 9.60% | 14.67% |
| E-30, E-32XS, S | (7.35)% | 6.84% | 14.19% |
| E-32M | (1.25)% | 8.76% | 10.01% |
| E-32L | 2.46% | 9.80% | 7.33% |
| E-34 | 7.47% | 11.05% | 3.58% |
| E-35 | 9.69% | 12.31% | 2.63% |
| Water Pumping | 16.47% | 10.54% | (5.93)% |
| Outdoor Lighting | 15.33% | 7.48% | (7.85)% |
| Dusk-to-Dawn | (0.98)% | 4.56% | 5.55% |
| Total | 8.77% | 8.77% | 0.00% |

As shown in Table KCH-3, APS's cost-of-service analysis shows the Residential class as warranting a base rate increase of 12.40 percent (at the Company's proposed revenue requirement), but receiving a base rate increase of just 3.95 percent. (As shown in Table KCH-4, when the effect of the PSA Reset is taken into account, the cost-based rate increase warranted by the Residential class at APS's proposed revenue requirement is 17.76 percent, and the proposed effective increase is 8.82 percent.)

At the same time, General Service customers are shown as warranting a base rate <u>decrease</u> of 6.80 percent (at the Company's proposed revenue requirement), but receiving a base rate <u>increase</u> of 2.64 percent. (When the effect of the PSA Reset is taken into account, the rate change warranted by the General

Service class is a reduction of 1.27 percent, and the proposed effective increase is 8.73 percent.) The upshot is that the cost-based rate change warranted by these two major groupings of customers is separated by more than 19 percentage points, but the base rate increase proposed by APS for these two groups is within 1.5 percentage points – and the effective rate increase (taking into account the PSA Reset) is virtually identical.

**Q. What is your assessment of APS's rate spread proposal?**

A. APS's proposed rate spread largely ignores cost of service ratemaking principles, while greatly expanding the very sizable subsidy that General Service customers pay to Residential customers. I calculate the proposed subsidy to be nearly $124 million per year.[8]

In my opinion, the Company's proposed rate spread does not reasonably reflect cost of service and should be rejected by the Commission. While the current economic climate is difficult for all customer classes, the magnitude of the inter-class subsidization in APS's proposal is an especially unreasonable burden to place upon the customers in the General Service class.

**Q. Do you have an alternative rate spread recommendation?**

A. Yes. I propose an approach that moves further in the direction of cost-of-service, while adhering to the principle of gradualism and providing continued rate mitigation for the Residential class. My proposal is summarized in the following five steps:

(1) Set Residential rates midway between system average percentage rate increase and the percentage increase necessary to bring Residential base rates to

[8] See Attachment KCH-6.

cost-of-service (taking into account the effect of the PSA Reset). This results in an overall rate increase for Residential customers that is within 5 percentage points of the system average rate increase.

(2) Cap the rate increase for other classes at 5 percentage points above the system average rate increase (taking into account the effect of the PSA Reset).

(3) Set Rate Schedules E-34 and E-35 (collectively) equal to cost-of-service, with both rate schedules receiving equal percentage increases (inclusive of the effect of the PSA Reset).

(4) Set the percentage increase for all remaining rate schedules (e.g., E-32, Dusk-to-Dawn) equal to the respective cost-of-service for each, plus the same percentage point increase necessary to fund the mitigation for Residential customers and the customer classes subject to the 5 percent cap.

(5) Within the E-32 grouping, apply the same percentage rate change to Rate Schedules E-32-M and E-32-L, as proposed by APS, in order to retain the same rate relationship between these two subgroups; at the same time, constrain the small commercial customer group (consisting of Rate Schedules E-30, E-32-XS, and E-32-S) such that its overall rate increase (inclusive of the effect of the PSA Reset) does not fall below zero, with any resulting revenues distributed among the remaining E-32 rate schedules on a pro-rata basis.

**Q. What is the rate spread that is obtained from your recommended approach at APS's proposed revenue requirement?**

A. These results are presented in Attachment KCH-7, and summarized in Tables KCH-5 and KCH-6, below.

**Table KCH-5**

**Comparison of AECC Rate Spread to APS Rate Spread**
**Base Rates Only**
At APS's Proposed Revenue Requirement

| Class | Base Rate Change per APS COS | APS Base Rate Change | AECC Base Rate Change |
|---|---|---|---|
| Residential | 12.40% | 3.95% | 8.15% |
| General Service | (6.80)% | 2.64% | (2.12)% |
| E-20 | 24.60% | 3.89% | 8.06% |
| E-32 (total) | (8.13)% | 2.53% | (2.58)% |
| GS TOU | (11.13)% | 2.60% | (5.65)% |
| E-30, E-32XS, S | (11.35)% | 2.22% | (4.32)% |
| E-32M | (6.69)% | 2.77% | (1.04)% |
| E-32L | (4.09)% | 2.77% | (1.04)% |
| E-34 | (0.25)% | 3.07% | 0.94% |
| E-35 | 0.95% | 3.37% | 0.09% |
| Water Pumping | 9.18% | 3.62% | 6.65% |
| Street Lighting | 11.19% | 3.62% | 9.68% |
| Dusk-to-Dawn | (2.52)% | 2.94% | 3.24% |
| | | | |
| Total | 3.33% | 3.33% | 3.33% |

**Table KCH-6**

**Comparison of AECC Rate Spread to APS Rate Spread**
**Combined Impact of Base Rates and PSA Reset**
At APS's Proposed Revenue Requirement

| Class | Combined Rate Change per APS COS | APS Combined Rate Change | AECC Combined Rate Change |
|---|---|---|---|
| Residential | 17.66% | 8.82% | 13.21% |
| General Service | (1.27)% | 8.73% | 3.69% |
| E-20 | 31.18% | 9.37% | 13.77% |
| E-32 (total) | (3.03)% | 8.23% | 2.83% |
| GS TOU | (5.07)% | 9.60% | 0.78% |
| E-30, E-32XS, S | (7.35)% | 6.84% | 0.00% |
| E-32M | (1.25)% | 8.76% | 5.21% |
| E-32L | (2.46)% | 9.80% | 5.21% |
| E-34 | 7.47% | 11.05% | 8.75% |
| E-35 | 9.69% | 12.31% | 8.75% |
| Water Pumping | 16.47% | 10.54% | 13.77% |
| Street Lighting | 15.33% | 7.48% | 13.77% |
| Dusk-to-Dawn | (0.98)% | 4.56% | 4.87% |
| | | | |
| Total | 8.77% | 8.77% | 8.77% |

**Q. Please explain the basis for your proposal to move Residential rates halfway to cost of service.**

A. In my opinion, moving Residential rates halfway to cost of service strikes a reasonable balance between setting rates based on cost while taking into consideration the principle of gradualism. This rate spread results in an overall rate increase for Residential customers that is less than 5 percentage points above the system average rate increase, which is the rate impact cap I am recommending for all other customers.

**Q. Please explain the basis for your proposed 5 percent cap for other rate schedules.**

A. The rates for the capped classes are significantly below cost of service. I recommend that rates for these classes be moved closer to cost, while, at the same time, in the interest of gradualism, I am recommending capping the overall rate increase for these two classes at five percentage points above the system average base rate increase. So, for example, at APS's proposed rate increase of 8.77 percent (inclusive of PSA Reset), the maximum overall rate increase for any rate schedule would be capped at 13.77 percent.

**Q. Please explain the basis for your proposed treatment of Rate Schedules 34 and 35.**

A. Rate Schedules 34 and 35 serve customers with demands greater than 3,000 kilowatts. The difference between the two rate schedules is that the charges for Rate 35 are differentiated on a time-of-use ("TOU") basis, whereas the charges for Rate 34 are not. Because these two rate schedules serve the same set of eligible customers, it is important to maintain a rational relationship between their respective designs. For example, it would make no sense to reduce Rate 34 significantly relative to Rate 35, so as to force Rate 35 customers to abandon TOU pricing and migrate to the flat energy charges of Rate 34. For this reason, I recommend treating the two rate schedules on a collective basis for rate spread purposes. Specifically, I am recommending that rates for these two rate schedules be set, collectively, equal to their cost of service, such that there is no subsidy in or out of this group. Further, in order to maintain the pricing relationship between these two rate schedules, I am recommending that each receives the same percentage increase (taking into account the effect of the PSA Reset).

**Q. Please explain the basis for your proposed treatment within the E-32 grouping in your fifth step.**

A. E-32 customers migrate between E-32-M and E-32-L as their demand usage falls above or below 400 kW. The relationship between the current rates of these rate schedules and their respective costs of service is similar. APS had proposed an identical base rate percentage change for these two rate schedules. In my proposal, I adopt the same concept, but apply it to the rate change inclusive of the PSA Reset. With respect to my recommendation for the small customer grouping, I note that after completing the first four steps of my recommended rate spread, this group would receive an overall rate reduction of $7 million at APS's proposed overall revenue requirement – even after taking into account the effect of the PSA Reset. In light of the substantial overall rate increase proposed by APS in this case, it is reasonable to constrain the overall rate change to this group to zero. I recommend that the monies resulting from this constraint be used within the E-32 group to offset part of the large subsidy paid by E-32 customers to other classes.

**Q. What approach to rate spread should be adopted if the Company's requested revenue requirement is reduced by the Commission?**

A. If the Company's requested rate increase is reduced by the Commission, I recommend that the same five steps I described above be applied to the reduced revenue requirement.

**Q. Steps 1 and 3 of your recommended rate spread approach are tied to the cost-of-service results at the approved revenue requirement. How should**

**your rate spread approach be applied if APS's cost-of-service study is not updated to reflect a reduced revenue requirement?**

A. In such a case, my recommended rate spread approach can be reasonably approximated by using the revenue apportionment produced by the rate spread shown in Table KCH-6 (which is applied to APS's proposed revenue requirement) as the basis for spreading the smaller revenue change.

**Q. Please explain this point further.**

A. When I refer to the "revenue apportionment produced by the rate spread shown in Table KCH-6" I am referring to each class's percentage share of total base revenue requirement that results from that spread. For example, under my proposed spread, Residential customers would pay 53.64 percent of the total base revenue requirement (see Attachment KCH-8). If the Commission agrees that this proposed rate spread is reasonable, then by extension, the corresponding revenue apportionment is reasonable as well.

The rate spread at a reduced revenue requirement would be determined by retaining the percentage revenue apportionment that results from my recommended rate spread at APS's proposed revenue requirement (Table KCH-6) and applying this revenue apportionment to the final revenue requirement approved by the Commission.

**Q. Do you have an example to illustrate how your approach would work?**

A. Yes. An example is presented in Attachment KCH-8. In this example, the revenue apportionment associated with my proposed rate spread at APS's proposed revenue requirement is first determined. Next, we assume that the Commission reduces APS's proposed revenue increase by $75 million. The resulting rate spread is then calculated by holding the revenue apportionment constant. The results are summarized in Table KCH-7, below. [9]

**Table KCH-7**

**Illustration of AECC Recommended Rate Spread Approach**
Example Illustrating $75 Million Revenue Reduction to APS's Revenue Proposal

| Class | Base Rate Change | Rate Change Inc. PSA Reset |
|---|---|---|
| Residential | 5.42% | 10.35% |
| General Service | (4.59)% | 1.07% |
| E-20 | 5.33% | 10.89% |
| E-32 (total) | (5.05)% | 0.23% |
| GS TOU | (8.04)% | (1.77)% |
| E-30, E-32XS, S | (6.74)% | (2.53)% |
| E-32M | (3.10)% | 2.55% |
| E-32L | (4.01)% | 2.55% |
| E-34 | (1.61)% | 6.00% |
| E-35 | (2.44)% | 6.00% |
| Water Pumping | 3.95% | 10.89% |
| Street Lighting | 6.91% | 10.89% |
| Dusk-to-Dawn | 0.63% | 2.22% |
| Total | 0.71% | 6.02% |

As shown in Table KCH-7, using a revenue apportionment approach results in each rate schedule retaining its basic relationship to the system average increase as occurs in the initial spread at APS's proposed revenue requirement; that is, the Residential class remains within 5 percentage points of the system average increase; capped classes remain approximately 5 percentage points above

[9] Note that the rate spread in Table KCH-7 shows some rate schedules receiving a rate decrease after taking account of the PSA Reset even though my proposal places a floor of 0% on the minimum rate increase – at APS's proposed revenue requirement. As APS's proposed revenue requirement is reduced, this constraint can either be retained – or relaxed – based on the Commission's assessment of whether a net rate decrease for some customers is reasonable in light of the size of the overall increase ultimately allowed (inclusive of the PSA Reset).

the system average increase; and the subsidy-paying classes retain approximately the same percentage differential below the system average increase as occurs in the initial spread at APS's proposed revenue requirement.

This consistency makes the revenue apportionment approach a useful tool for adjusting rate spread when a Commission reduces the revenue requirement from the utility's proposal, but the class cost-of-service study is not also simultaneously updated to reflect this reduction.

## INTERRUPTIBLE RATE RIDER

**Q. What is APS proposing with respect to an Interruptible Rate Rider?**

A. As discussed by Mr. Miessner, APS is proposing the adoption of Rate Rider Schedule IRR, which would offer interruptible service to extra-large general service customers that can interrupt at least 500 kW of load when requested by APS. Rate Rider Schedule IRR would offer the customer a combination of options for participation.

**Q. What is your assessment of APS's proposal to adopt Rate Rider Schedule IRR?**

A. I support the adoption of Rate Rider Schedule IRR, but with modifications. If structured properly, interruptible rates can be a cost-effective means for utilities to obtain reliable capacity. In my opinion, it is important for interruptible service to be included in APS's resource mix, as it can provide benefits for both the Company as well as the customers with the operational flexibility to perform under an interruptible rider. Indeed, the inclusion of an APS interruptible rider was approved in concept as part of Decision 71448 approving the Settlement Agreement in APS's previous rate case. APS's proposal in this docket simply represents the implementation of this conceptual approval.

**Q. What modifications do you recommend to Rate Rider Schedule IRR?**

A. I recommend changing the basis of the credit paid to participating customers from "50% demand / 50% energy" as proposed by APS to "100% demand." I also recommend that the Rider include a multiyear schedule of capacity rates, rather than a single rate that will stand until the next general rate case.

**Q. Please explain your first recommended modification.**

A. APS's approach understates the value of the capacity being provided by participating customers by half. APS indicates that the gross value of the capacity that would be provided by interruptible customers in 2012 is $21.07 per kW-year (including losses).[10] (To put this in perspective, APS proposes to *charge* E-34 customers more than $126 per kW-year for generation capacity in 2012.) The gross value of this avoided capacity cost is then reduced to a factor of 56.9% or 76.7% (depending on the interruption option selected by the customer) to account for the more limited availability of interruptions relative to generation capacity.

I do not object to the reasonableness of these factors. However, APS then goes on to propose that only 50 percent of the credit paid to participating customers be recognized as a credit against the customer's demand charge and 50 percent paid out as an energy credit for actual interruptions. This approach understates the value of the capacity provided by participants (which is already being assigned a relatively low gross valuation to start with). The product that

[10] Source: APS Data Response to Staff 3.066.

interruptible customers are offering is capacity: indeed the value of their payment is derived strictly from the value of avoided capacity. Therefore, it is appropriate that 100 percent of the credit paid to participating customers be in the form of a demand credit, rather than just 50 percent. This problem can be corrected by eliminating the proposed energy credit and doubling the proposed demand credit.

**Q. Please explain your proposed modification regarding a multiyear credit schedule.**

A. The one-year credit proposed by APS is based on 2012 estimates of avoided capacity cost. However, APS's projected value of avoided capacity increases each year. While these increasing avoided capacity values are reflected in the five-year option proposed by APS, there is no provision for them to be reflected in the one-year option. As APS typically does not file a rate case each year, the one-year capacity credit will become stale. It makes sense to be sending the right price signal for this capacity; if it is expected to become more valuable going forward, that should be reflected in the Rider through a multiyear pricing provision – until superseded in a subsequent rate case.

**Q. What is your recommendation to the Commission with respect to proposed Rate Rider Schedule IRR?**

A. I recommend that the Commission approve Rate Rider Schedule IRR, but with the two modifications I recommended above.

## EXPERIMENTAL RATE RIDER AG-1

**Q. What is APS's proposal for Experimental Rate Rider AG-1?**

A. As presented by Mr. Miessner, Experimental Rate Rider AG-1 would allow an E-34 or E-35 customer with an average monthly demand of 10 MW or more to obtain an alternative source of generation to serve its full power requirements. APS will purchase and manage the generation on behalf of the customer for a management fee of $0.0006 per kWh. APS will also provide scheduling, and if necessary, load following service.

**Q. What is your assessment of the Company's proposal for Experimental Rate Rider AG-1?**

A. The new product offering described by APS is sometimes called a "buy-through." This product has a similarity to direct access service, but the utility (in this case APS) acts as the middleman between customer and the market, rather than an Electric Service Provider ("ESP") playing this role.

In general, I support APS's proposal to make this option available to customers.

**Q. Do you believe that Experimental Rate Rider AG-1 can be a good substitute for a policy of reinstating direct access service in Arizona?**

A. No. AECC continues to advocate for a reactivation of direct access service in Arizona. I see the Experimental Rate Rider AG-1 proposed by APS as complementary to direct access service in that it would provide a means through which certain qualifying customers can gain access to market generation. This is a potentially valuable option that is not available to APS customers today due to the de facto suspension on Electric Service Provider ("ESP") certification approvals. While I support approval of this proposed rider, this limited buy-through approach still falls short of providing the potential benefits to customers that can occur from reinstating direct access service, which would be available to a broader range of customers and market participants.

**Q. What benefits would accrue to customers from reinstating direct access service in Arizona?**

A. Broadly speaking, customers would be able to avail themselves of market-priced power, which can be shaped by an ESP to fit the customer's time horizon and risk tolerance. It would also open the playing field to new market participants, who would bring their own competitive attributes. Direct access would also allow interested customers to acquire a wider range of renewable energy products to further their corporate or organizational objectives.

**Q. Are there any specific terms in Experimental Rate Rider AG-1 that you propose to change?**

A. Yes. The proposed Rider includes a provision for a "Reserve Capacity Charge" equal to 15 percent of the customer's monthly peak load. However, the Rider also requires that the product provided by the Generation Service provider be firm service. Firm service must be backed by reserves. Thus, the customer is already paying for reserves and it appears that the Reserve Capacity Charge would force the customer to pay twice for them. This double-charge is unwarranted. Moreover, the rate for the proposed Reserve Capacity Charge is not specified in the Rider, which is problematic.

**Q. What is your recommendation to the Commission regarding the Experimental Rate Rider AG-1?**

A. I recommend that it be approved by the Commission, but the requirement to pay a Reserve Capacity Charge should be removed. I also recommend that Experimental Rate Rider AG-1 should not be viewed as a substitute for reinstating full direct access service in Arizona.

## <u>RATE DESIGN FOR RATE SCHEDULE E-32-L</u>

**Q. What change APS proposed with respect to rate design for Rate Schedule E-32-L?**

A. As discussed by Mr. Miessner, APS is proposing to remove the first tier energy charge for this rate schedule, modify the remaining energy charge to reflect the average energy cost per kWh, and to revise the demand charge to include the implicit demand-related costs that are currently recovered through the first tier energy charge.

**Q. Do you support this rate design change?**

A. Yes, I do. A demand charge is the preferred vehicle for recovery of demand-related costs for customers of this size. This change will make the structure of the E-32-L rate more closely aligned with that of Rate Schedule E-34.

**Q. Does this restructuring of the design for Rate Schedule E-32-L lend support to your argument in your revenue-requirements testimony that customers on this rate schedule should be exempt from decoupling (if decoupling is adopted)?**

A. Yes, it does. This rate redesign effectively removes fixed cost recovery from the E-32-L energy charge, which means that if E-32-L customers reduce their energy usage due to improved efficiency, it should not significantly impact APS's fixed cost recovery. Consequently, the premise for including these customers in any decoupling scheme is further weakened.

**RATE DESIGN FOR RATE SCHEDULES E-34 AND E-35**

**Q. Do you have any concerns regarding the rate design for Rate Schedules E-34 and E-35?**

A. Yes, I do. As I discussed above regarding rate spread, APS has focused its case on changes in base rates, without a great deal of consideration given to the fact that customers will be impacted through the elimination (or substantial reduction) of the PSA credit that will accompany the establishment of new rates. This issue has implications for rate design.

Specifically, in the case of E-34 and E-35 customers, APS is proposing what appears to be a small increase in the *base* energy charge, i.e., around 1%. However, this proposal ignores the fact that *real* energy charge paid by these customers today is some 15 percent lower than the base energy charge – due to the credit of $0.005658/kWh in the PSA. Thus, the 1% increase in the base energy charge proposed by APS is actually a **16% increase** in the overall energy rates paid by these customers. Such an increase is unreasonable; indeed, APS's fuel costs in base rates are going down, not up. The E-34 and E-35 energy charge should reflect this fact.

**Q. If, as part of your rate design proposal, the E-34 and E-35 energy charges are reduced relative to what APS has proposed, does this cause costs to be passed to customers in other rate schedules?**

A. No, not at all. If, as part of rate design, the E-34 and E-35 energy charge is reduced, the revenue is made up by increasing the E-34 and E-35 demand charges sufficiently to recover the revenue requirement assigned to these respective rate schedules.

**Q. From a customer's perspective, why should it matter if the utility proposes a rate design that overprices the energy charge and understates the demand charge?**

A. For a given rate schedule, when the energy charge is set above energy cost, and consequently demand-related charges are set below demand-related cost, those customers with relatively-higher load factors are required to subsidize the costs of the lower-load-factor customers within the rate class. In the case at hand, APS's proposed rate design would cause a greater rate overall rate increase (inclusive of the PSA Reset) on its higher-load-factor customers within E-34 and E-35 than on the lower-load-factor customers on those rate schedules. Since fuel costs are coming down, this disparate impact on higher-load-factor customers is unreasonable.

**Q. What is your rate design recommendation for Rate Schedules E-34 and E-35?**

A. I recommend that the energy charge for these two rate schedules be set equal to the current base energy rate *minus* the amount of the current credit in the

Forward Component of the PSA.[11] This price represents the current effective energy charges for these rate schedules, setting aside the Historical Component in the PSA. As fuel costs are declining, the energy charges for E-34 and E-35 customers should not be increased above this level.

**Q. Have you prepared an alternative rate design based on your recommendation?**

A. Yes. I have prepared an alternative rate design that implements my recommendation using APS's proposed revenue requirement for these two rate schedules. This is presented in Attachment KCH-9. If APS's revenue requirement for Rate Schedules E-34 and E-35 is reduced by the Commission, this same rate design approach can be applied to the lower revenue requirement; that is, the energy charge would be established as I describe above, and the demand charge would be set at a rate sufficient to recover the remaining revenue requirement.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

[11] The PSA Forward Component is currently $0.003016/kWh.

# APS Proposed Rate Spread at APS's Requested Revenue Increase

(Base Rates Only)

## APS Proposed Revenue Increase for each Customer Class

| | (a) | (b) | (c) | (d) | (e) = (d) ÷ (c) | (f) = (e) ÷ (e) Total | (g) | (h) = (b) Total x Class Share of RB - Col. (c) | (i) = (g) + (h) | (j) = (i) ÷ (b) | (k) | (l) = (k) ÷ (b) | (m) = (i) - (k) | (n) = (m) ÷ (b) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Current Retail Base Revenues[1] | Rate Base[1] | Return Req'd Return @ Equal ROR[1] | Equalized Rate of Return | Equalized Relative Rate of Return | Required COS Revenue Increase[1] | Fair Value Revenue Increase[1] | Req'd COS + Fair Value Revenue Increase | Req'd Percent Change | APS Proposed Base Revenue Increase[2] | APS Base Percent Change | APS Proposed Subsidy | APS Proposed Subsidy Percent | Line No. |
| 1 | Residential | $1,470,133,000 | $3,419,731,000 | $303,330,000 | 8.87% | 1.00 | $157,824,000 | $24,441,000 | $182,265,000 | 12.40% | $58,104,000 | 3.95% | $124,161,000 | 8.45% | 1 |
| 2 | General Service | | | | | | | | | | | | | | 2 |
| 3 | E-20 | $3,886,000 | $10,797,000 | $958,000 | 8.87% | 1.00 | $879,000 | $77,000 | $956,000 | 24.60% | $151,000 | 3.89% | $805,000 | 20.72% | 3 |
| 4 | E-32 TOU (Combined) | $34,389,000 | $44,976,000 | $3,989,000 | 8.87% | 1.00 | ($4,149,000) | $321,000 | ($3,828,000) | -11.13% | $894,000 | 2.60% | ($4,722,000) | -13.73% | 4 |
| 5<br>6 | E-30, E-32 (0 - 20 kW)<br>E-32 (21 - 100 kW) | $490,605,000 | $852,781,000 | $75,642,000 | 8.87% | 1.00 | ($61,783,000) | $6,095,000 | ($55,688,000) | -11.35% | $10,911,000 | 2.22% | ($66,599,000) | -13.57% | 5<br>6 |
| 7 | E-32 (101 - 400 kW) | $317,315,000 | $521,011,000 | $46,214,000 | 8.87% | 1.00 | ($24,944,000) | $3,724,000 | ($21,220,000) | -6.69% | $8,791,000 | 2.77% | ($30,011,000) | -9.46% | 7 |
| 8 | E-32 (401+ kW) | $303,798,000 | $471,198,000 | $41,795,000 | 8.87% | 1.00 | ($15,807,000) | $3,368,000 | ($12,439,000) | -4.09% | $8,418,000 | 2.77% | ($20,857,000) | -6.87% | 8 |
| 9 | E-30, E-32 Subtotal | $1,146,107,000 | $1,889,966,000 | $167,640,000 | 8.87% | 1.00 | ($106,683,000) | $13,508,000 | ($93,175,000) | -8.13% | $29,014,000 | 2.53% | ($122,189,000) | -10.66% | 9 |
| 10 | E-34 | $80,597,000 | $117,735,000 | $10,443,000 | 8.87% | 1.00 | ($1,043,000) | $841,000 | ($202,000) | -0.25% | $2,476,000 | 3.07% | ($2,678,000) | -3.32% | 10 |
| 11 | E-35 | $112,009,000 | $140,920,000 | $12,500,000 | 8.87% | 1.00 | $57,000 | $1,007,000 | $1,064,000 | 0.95% | $3,772,000 | 3.37% | ($2,708,000) | -2.42% | 11 |
| 12 | General Service Total | $1,342,599,000 | $2,159,418,000 | $191,541,000 | 8.87% | 1.00 | ($106,790,000) | $15,433,000 | ($91,357,000) | -6.80% | $35,413,000 | 2.64% | ($126,770,000) | -9.44% | 12 |
| 13 | Water Pumping (E-38, E-221) | $26,669,000 | $45,658,000 | $4,050,000 | 8.87% | 1.00 | $2,122,000 | $326,000 | $2,448,000 | 9.18% | $966,000 | 3.62% | $1,482,000 | 5.56% | 13 |
| 14 | Outdoor/Street Lighting | $20,999,000 | $67,341,000 | $5,973,000 | 8.87% | 1.00 | $1,869,000 | $481,000 | $2,350,000 | 11.19% | $761,000 | 3.62% | $1,589,000 | 7.57% | 14 |
| 15 | Dusk to Dawn | $8,457,000 | $28,130,000 | $2,495,000 | 8.87% | 1.00 | ($414,000) | $201,000 | ($213,000) | -2.52% | $249,000 | 2.94% | ($462,000) | -5.46% | 15 |
| 16 | ACC Total | $2,868,857,000 | $5,720,278,000 | $507,389,000 | 8.87% | 1.00 | $54,611,000 | $40,883,000 | $95,493,000 | 3.33% | $95,493,000 | 3.33% | $0 | 0.00% | 16 |

1. Data Source: ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010
2. Data Source: APS SFR Schedule H-2

# APS Proposed Rate Spread at APS's Requested Revenue Increase

(Combined Impact of Base Rates and PSA Credit Reset)

## APS Proposed Revenue Increase for each Customer Class

| | (a) | (b) | (c) Attach. KCH-6, p. 1, Col. (i) | (d) | (e) = (c) + (d) | (f) = (e) ÷ [(b) - (d)] | (g) Attach. KCH-6, p. 1, Col. (k) + (d) | (h) = (g) ÷ [(b) - (d)] | (i) = (e) - (g) | (j) = (i) ÷ (b) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Current Retail Base Revenues[1] | Required COS + Fair Value Revenue Increase | Reset of PSA Credit Increase[2] | Total COS + Fair Value with Reset of PSA Credit Increase | Req'd Percent Change | APS Proposed Revenue Increase with Reset of PSA Credit | APS Base Percent Change | APS Proposed Subsidy | APS Proposed Subsidy Percent | Line No. |
| 1 | Residential | $1,470,133,000 | $182,265,000 | $65,722,000 | $247,987,000 | 17.66% | $123,826,000 | 8.82% | $124,161,000 | 8.45% | 1 |
| 2 | General Service | | | | | | | | | | 2 |
| 3 | E-20 | $3,886,000 | $956,000 | $195,000 | $1,151,000 | 31.18% | $346,000 | 9.37% | $805,000 | 20.72% | 3 |
| 4 | E-32 TOU (Combined) | $34,389,000 | ($3,828,000) | $2,196,000 | ($1,632,000) | -5.07% | $3,090,000 | 9.60% | ($4,722,000) | -13.73% | 4 |
| 5 | E-30, E-32 (0 - 20 kW) | $490,605,000 | ($55,688,000) | $21,204,000 | ($34,484,000) | -7.35% | $32,115,000 | 6.84% | ($66,599,000) | -13.57% | 5 |
| 6 | E-32 (21 - 100 kW) | | | | | | | | | | 6 |
| 7 | E-32 (101 - 400 kW) | $317,315,000 | ($21,220,000) | $17,484,000 | ($3,736,000) | -1.25% | $26,275,000 | 8.76% | ($30,011,000) | -9.46% | 7 |
| 8 | E-32 (401+ kW) | $303,798,000 | ($12,439,000) | $19,444,000 | $7,005,000 | 2.46% | $27,862,000 | 9.80% | ($20,857,000) | -6.87% | 8 |
| 9 | E-30, E-32 Subtotal | $1,146,107,000 | ($93,175,000) | $60,328,000 | ($32,847,000) | -3.03% | $89,342,000 | 8.23% | ($122,189,000) | -10.66% | 9 |
| 10 | E-34 | $80,597,000 | ($202,000) | $5,790,000 | $5,588,000 | 7.47% | $8,266,000 | 11.05% | ($2,678,000) | -3.32% | 10 |
| 11 | E-35 | $112,009,000 | $1,064,000 | $8,921,000 | $9,985,000 | 9.69% | $12,693,000 | 12.31% | ($2,708,000) | -2.42% | 11 |
| 12 | General Service Total | $1,342,599,000 | ($91,357,000) | $75,234,000 | ($16,123,000) | -1.27% | $110,647,000 | 8.73% | ($126,770,000) | -9.44% | 12 |
| 13 | Water Pumping (E-38, E-221) | $26,669,000 | $2,448,000 | $1,670,000 | $4,118,000 | 16.47% | $2,636,000 | 10.54% | $1,482,000 | 5.56% | 13 |
| 14 | Outdoor/Street Lighting | $20,999,000 | $2,350,000 | $754,000 | $3,104,000 | 15.33% | $1,515,000 | 7.48% | $1,589,000 | 7.57% | 14 |
| 15 | Dusk to Dawn | $8,457,000 | ($213,000) | $131,000 | ($82,000) | -0.98% | $380,000 | 4.56% | ($462,000) | -5.46% | 15 |
| 16 | ACC Total | $2,868,857,000 | $95,493,000 | $143,511,000 | $239,004,000 | 8.77% | $239,004,000 | 8.77% | $0 | 0.00% | 16 |

1. Data Source: ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010
2. Data Source: APS Response to AECC Data Request No. 1.1

# AECC Recommended Rate Spread at APS's Requested Revenue Increase

AECC Recommended Revenue Increase for each Customer Class based on APS's Cost of Service Study

E-20, Water Pumping & Outdoor/Streetlighting Adder above System Average Increase = 5.00%

Gen. Serv. TOU, E-30, E-32, Dusk to Dawn Adder Above Cost = 5.85%

| Line No. | Rate Class | Current Retail Base Revenues[1] | Rate Base[1] | Return Req'd Return @ Equal ROR[1] | Req'd COS + Fair Value Revenue Increase[1] | Req'd Percent Change | Reset of PSA Credit Increase[2] | Req'd "COS" Base Revenue Increase | Req'd "COS" Base Percent Change | First Pass AECC Recommended Base Revenue Including Reset of PSA Credit Revenue | First Try AECC Base Percent Change Including Reset of PSA Credit | Second Pass AECC Recommended Base Revenue Including Reset of PSA Credit Revenue | Second Try AECC Base Percent Change Including Reset of PSA Credit | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (g) | (h) = (g) ÷ (b) | (i) | (j) = (g) + (i) | (k) = (j) ÷ [(b) - (i)] | (l) = (m) x [(b) - (i)] | (m) = Input | (n) = (o) x [(b) - (i)] | (o) = Input | |
| 1 | Residential | $1,470,133,000 | $3,419,731,000 | $303,330,000 | $182,265,000 | 12.40% | $65,722,000 | $247,987,000 | 17.66% | $185,574,644 | 13.21% | $185,574,644 | 13.21% | 1 |
| 2 | General Service | | | | | | | | | | | | | 2 |
| 3 | E-20 | $3,886,000 | $10,797,000 | $958,000 | $956,000 | 24.60% | $195,000 | $1,151,000 | 31.18% | $508,239 | 13.77% | $508,239 | 13.77% | 3 |
| 4 | E-32 TOU (Combined) | $34,389,000 | $44,976,000 | $3,989,000 | ($3,828,000) | -11.13% | $2,196,000 | ($1,632,000) | -5.07% | $252,527 | 0.78% | $252,527 | 0.78% | 4 |
| 5 | E-30, E-32 (0 - 20 kW) | $490,605,000 | $852,781,000 | $75,642,000 | ($55,688,000) | -11.35% | $21,204,000 | ($34,484,000) | -7.35% | ($7,806,012) | -1.49% | $0 | 0.00% | 5 |
| 6 | E-32 (21 - 100 kW) | | | | | | | | | | | | | 6 |
| 7 | E-32 (101 - 400 kW) | $317,315,000 | $521,011,000 | $46,214,000 | ($21,220,000) | -6.69% | $17,484,000 | ($3,736,000) | -1.25% | $13,815,630 | 4.61% | $30,460,248 | 5.21% | 7 |
| 8 | E-32 (401+ kW) | $303,798,000 | $471,198,000 | $41,795,000 | ($12,439,000) | -4.09% | $19,444,000 | $7,005,000 | 2.46% | $23,650,631 | 8.32% | | | 8 |
| 9 | E-30, E-32 Subtotal | $1,146,107,000 | $1,889,966,000 | $167,640,000 | ($93,175,000) | -8.13% | $60,328,000 | ($32,847,000) | -3.03% | $30,712,775 | 2.83% | $30,712,775 | 2.83% | 9 |
| 10 | E-34 | $80,597,000 | $117,735,000 | $10,443,000 | ($202,000) | -0.25% | $5,790,000 | $5,588,000 | 7.47% | $6,548,635 | 8.75% | $6,548,635 | 8.75% | 10 |
| 11 | E-35 | $112,009,000 | $140,920,000 | $12,500,000 | $1,064,000 | 0.95% | $8,921,000 | $9,985,000 | 9.69% | $9,024,365 | 8.75% | $9,024,365 | 8.75% | 11 |
| 12 | General Service Total | $1,342,599,000 | $2,159,418,000 | $191,541,000 | ($91,357,000) | -6.80% | $75,234,000 | ($16,123,000) | -1.27% | $46,794,014 | 3.69% | $46,794,014 | 3.69% | 12 |
| 13 | Water Pumping (E-38, E-221) | $26,669,000 | $45,658,000 | $4,050,000 | $2,448,000 | 9.18% | $1,670,000 | $4,118,000 | 16.47% | $3,442,281 | 13.77% | $3,442,281 | 13.77% | 13 |
| 14 | Outdoor/Street Lighting | $20,999,000 | $67,341,000 | $5,973,000 | $2,350,000 | 11.19% | $754,000 | $3,104,000 | 15.33% | $2,787,671 | 13.77% | $2,787,671 | 13.77% | 14 |
| 15 | Dusk to Dawn | $8,457,000 | $28,130,000 | $2,495,000 | ($213,000) | -2.52% | $131,000 | ($82,000) | -0.98% | $405,391 | 4.87% | $405,391 | 4.87% | 15 |
| 16 | ACC Total | $2,868,857,000 | $5,720,278,000 | $507,389,000 | $95,493,000 | 3.33% | $143,511,000 | $239,004,000 | 8.77% | $239,004,000 | 8.77% | $239,004,000 | 8.77% | 16 |

1. Data Source: ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010
2. Data Source: APS Response to AECC Data Request No. 1.1

# AECC Recommended Rate Spread Approach
## Example Illustrating a $75 Million Revenue Reduction to APS's Requested Increase
## Including Reset of PSA Credit

Revenue Spread at Assumed $164 Million Increase

| | (a) | (b) | (c) | (d) = (b) + (c) | (e) Attachment KCH-6 Column (n) | (f) = (d) + (e) | (i) = (f) ÷ (f) Total | (j) = (i) x (j) Total | (k) = (j) - (d) | (l) = (k) ÷ (d) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Current Retail Base Revenues[1] | PSA Credit Revenue | Current Revenue Inclusive of PSA Credit | AECC Recommended Base Revenue Increase Including Reset of PSA Credit Revenue | AECC Recommended Retail Base Revenue at APS' Requested Increase | Revenue Apportionment Percentage | AECC Recommended Retail Base Revenue | AECC Recommended Base Revenue Increase | AECC Base Percent Change | Line No. |
| 1 | Residential | $1,470,133,000 | ($65,722,000) | $1,404,411,000 | $185,574,644 | $1,589,985,644 | 53.64% | $1,549,757,964 | $145,346,964 | 10.35% | 1 |
| 2 | General Service | | | | | | | | | | 2 |
| 3 | E-20 | $3,886,000 | ($195,000) | $3,691,000 | $508,239 | $4,199,239 | 0.14% | $4,092,995 | $401,995 | 10.89% | 3 |
| 4 | E-32 TOU (Combined) | $34,389,000 | ($2,196,000) | $32,193,000 | $252,527 | $32,445,527 | 1.09% | $31,624,634 | ($568,366) | -1.77% | 4 |
| 5 | E-30, E-32 (0 - 20 kW) | $490,605,000 | ($21,204,000) | $469,401,000 | $0 | $469,401,000 | 15.83% | $457,524,847 | ($11,876,153) | -2.53% | 5 |
| 6 | E-32 (21 - 100 kW) | | | | | | | | | | 6 |
| 7 | E-32 (101 - 400 kW) | $317,315,000 | ($17,484,000) | $299,831,000 | $30,460,248 | $614,645,248 | 20.73% | $307,482,687 | $7,651,687 | 2.55% | 7 |
| 8 | E-32 (401+ kW) | $303,798,000 | ($19,444,000) | $284,354,000 | | | | $291,611,633 | $7,257,633 | 2.55% | 8 |
| 9 | E-30, E-32 Subtotal | $1,146,107,000 | ($60,328,000) | $1,085,779,000 | $30,712,775 | $1,116,491,775 | 37.66% | $1,088,243,800 | $2,464,800 | 0.23% | 9 |
| 10 | E-34 | $80,597,000 | ($5,790,000) | $74,807,000 | $6,548,635 | $81,355,635 | 6.53% | $79,296,916 | $4,489,916 | 6.00% | 10 |
| 11 | E-35 | $112,009,000 | ($8,921,000) | $103,088,000 | $9,024,365 | $112,112,365 | | $109,276,217 | $6,188,217 | 6.00% | 11 |
| 12 | General Service Total | $1,342,599,000 | ($75,234,000) | $1,267,365,000 | $46,794,014 | $1,314,159,014 | 44.33% | $1,280,909,928 | $13,544,928 | 1.07% | 12 |
| 13 | Water Pumping (E-38, E-221) | $26,669,000 | ($1,670,000) | $24,999,000 | $3,442,281 | $28,441,281 | 0.96% | $27,721,698 | $2,722,698 | 10.89% | 13 |
| 14 | Outdoor/Street Lighting | $20,999,000 | ($754,000) | $20,245,000 | $2,787,671 | $23,032,671 | 0.78% | $22,449,929 | $2,204,929 | 10.89% | 14 |
| 15 | Dusk to Dawn | $8,457,000 | ($131,000) | $8,326,000 | $405,391 | $8,731,391 | 0.29% | $8,510,481 | $184,481 | 2.22% | 15 |
| 16 | ACC Total | $2,868,857,000 | ($143,511,000) | $2,725,346,000 | $239,004,000 | $2,964,350,000 | 100.00% | $2,889,350,000 | $164,004,000 | 6.02% | 16 |

# AECC Recommended Rate Design at APS's Requested Revenue Increase
## General Service E-34 Rates
## Test Year Ending Dec 31, 2010

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|---|---|
| | | APS (As Filed)[1] | | | AECC Proposed | | |
| Line No. | Bundled Rates | Present | Proposed | % Change | Present | Proposed | % Change |
| 1 | *Basic Service Charge* | | | | | | |
| 2 | Self-Contained | $ 1.135 | $ 0.658 | -42.0% | $ 1.135 | $ 0.658 | -42.0% |
| 3 | Instrument-Rated | $ 1.776 | $ 1.328 | -25.2% | $ 1.776 | $ 1.328 | -25.2% |
| 4 | Primary Voltage | $ 3.828 | $ 3.477 | -9.2% | $ 3.828 | $ 3.477 | -9.2% |
| 5 | Transmission Voltage | $ 26.161 | $ 26.855 | 2.7% | $ 26.161 | $ 26.855 | 2.7% |
| 6 | *Demand Charges:* | | | | | | |
| 7 | Secondary Service | $ 17.377 | $ 16.646 | -4.2% | $ 17.377 | $ 18.588 | 7.0% |
| 8 | Primary Service | $ 16.478 | $ 15.687 | -4.8% | $ 16.478 | $ 17.629 | 7.0% |
| 9 | Transmission Service | $ 12.005 | $ 10.914 | -9.1% | $ 12.005 | $ 12.856 | 7.1% |
| 10 | Primary substation - Military Base | $ 12.787 | $ 11.749 | 0 | $ 12.787 | $ 13.691 | |
| 11 | *Energy Charge* | $ 0.04220 | $ 0.04258 | 0.9% | $ 0.04220 | $ 0.03873 | -8.2% |
| | **Unbundled Rates** | | | | | | |
| 12 | *Basic Service Charge* | | | | | | |
| 13 | *per day* | $ 0.601 | $ 0.129 | -78.5% | $ 0.601 | $ 0.129 | -78.5% |
| 14 | *Metering per day* | | | | | | |
| 15 | Self-Contained | $ 0.395 | $ 0.414 | 4.8% | $ 0.395 | $ 0.4140 | 4.8% |
| 16 | Instrument-Rated | $ 1.036 | $ 1.084 | 4.6% | $ 1.036 | $ 1.0840 | 4.6% |
| 17 | Primary Voltage | $ 3.088 | $ 3.233 | 4.7% | $ 3.088 | $ 3.2330 | 4.7% |
| 18 | Transmission Voltage | $ 25.421 | $ 26.611 | 4.7% | $ 25.421 | $ 26.6110 | 4.7% |
| 19 | Meter Reading per day | $ 0.066 | $ 0.038 | -42.4% | $ 0.066 | $ 0.0380 | -42.4% |
| 20 | Billing per day | $ 0.073 | $ 0.077 | 5.5% | $ 0.073 | $ 0.0770 | 5.5% |
| 21 | Systems Benefit per kWh | $ 0.00210 | 0.00165 | -21.4% | $ 0.00210 | $ 0.00165 | -21.4% |
| 22 | Transmission Charge | | | | | | |
| 23 | Per kWh | | | | | | |
| 24 | Per kW | $ 1.776 | $ - | -100.0% | $ 1.776 | $ - | -100.0% |
| 25 | Delivery Charge per kW; | | | | | | |
| 26 | Secondary Service | $ 5.635 | $ 6.012 | 6.7% | $ 5.635 | $ 6.012 | 6.7% |
| 27 | Primary Service | $ 4.736 | $ 5.053 | 6.7% | $ 4.736 | $ 5.053 | 6.7% |
| 28 | Transmission Service | $ 0.263 | $ 0.280 | 6.5% | $ 0.263 | $ 0.280 | 6.5% |
| 29 | Primary substation - Military Base | $ 1.045 | $ 1.115 | 6.7% | $ 1.045 | $ 1.115 | 6.7% |
| 30 | Generation Charge | | | | | | |
| 31 | Per kW | $ 9.966 | $ 10.634 | 6.7% | $ 9.966 | $ 12.576 | 26.2% |
| 32 | Per kWh | $ 0.04010 | $ 0.04093 | 2.1% | $ 0.04010 | $ 0.037083 | -7.5% |
| 33 | | | | | | | |
| 34 | Delivery Discounts from Secondary Service ($/kW) | | | | | | |
| 35 | Primary Service | $ 0.899 | $ 0.959 | 0 | $ 0.899 | $ 0.959 | |
| 36 | Transmission Service | $ 5.372 | $ 5.732 | 0 | $ 5.372 | $ 5.732 | |
| 37 | Primary substation - Military Base | $ 4.590 | $ 4.897 | 0 | $ 4.590 | $ 4.897 | |

1. Data Source: APS Witness Miessner CAM_WP 13, Proof of Revenue

# AECC Recommended Rate Design at APS's Requested Revenue Increase
# General Service E-35 Rates
# Test Year Ending Dec 31, 2010

| | (a) | (b) | | (c) | | (d) | (e) | | (f) | | (g) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | APS (As Filed)[1] | | | | | AECC Proposed | | | | |
| Line No. | Bundled Rates | Present | | Proposed | | % Change | Present | | Proposed | | % Change |
| 1 | *Basic Service Charge* | | | | | | | | | | |
| 2 | Self-Contained | $ | 1.183 | $ | 0.658 | -44.4% | $ | 1.183 | $ | 0.658 | -44.4% |
| 3 | Instrument-Rated | $ | 1.795 | $ | 1.328 | -26.0% | $ | 1.795 | $ | 1.328 | -26.0% |
| 4 | Primary Voltage | $ | 3.881 | $ | 3.477 | -10.4% | $ | 3.881 | $ | 3.477 | -10.4% |
| 5 | Transmission Voltage | $ | 26.574 | $ | 26.855 | 1.1% | $ | 26.574 | $ | 26.855 | 1.1% |
| 6 | *Demand Charges:* | | | | | | | | | | |
| 7 | Secondary Service | | | | | | | | | | |
| 8 | On-Peak | $ | 15.091 | $ | 14.351 | -4.9% | $ | 15.091 | $ | 16.606 | 10.0% |
| 9 | Off-Peak | $ | 2.734 | $ | 2.945 | 7.7% | $ | 2.734 | $ | 2.945 | 7.7% |
| 10 | Primary Service | | | | | | | | | | |
| 11 | On-Peak | $ | 14.343 | $ | 13.545 | -5.6% | $ | 14.343 | $ | 15.800 | 10.2% |
| 12 | Off-Peak | $ | 2.659 | $ | 2.864 | 7.7% | $ | 2.659 | $ | 2.864 | 7.7% |
| 13 | Transmission Service | | | | | | | | | | |
| 14 | On-Peak | $ | 10.483 | $ | 9.385 | -10.5% | $ | 10.483 | $ | 11.640 | 11.0% |
| 15 | Off-Peak | $ | 2.273 | $ | 2.448 | 7.7% | $ | 2.273 | $ | 2.448 | 7.7% |
| 16 | Primary Substation - Military Base | | | | | | | | | | |
| 17 | On-Peak | $ | 11.520 | $ | 10.502 | -8.8% | $ | 11.520 | $ | 12.757 | 10.7% |
| 18 | Off-Peak | $ | 2.376 | $ | 2.559 | 7.7% | $ | 2.376 | $ | 2.559 | 7.7% |
| 19 | *Energy Charge* | | | | | | | | | | |
| 20 | On-Peak | $ | 0.04694 | $ | 0.04749 | 1.2% | $ | 0.04694 | $ | 0.04347 | -7.4% |
| 21 | Off-Peak | $ | 0.03530 | $ | 0.03559 | 0.8% | $ | 0.03530 | $ | 0.03183 | -9.8% |
| | Unbundled Rates | | | | | | | | | | |
| 22 | Basic Service Charge | $ | 0.601 | $ | 0.129 | -78.5% | $ | 0.601 | $ | 0.129 | -78.5% |
| 23 | Revenue Cycle Service Charges | | | | | | | | | | |
| 24 | Self Contained | $ | 0.440 | $ | 0.414 | -5.9% | $ | 0.440 | $ | 0.414 | -5.9% |
| 25 | Instrument-Rated | $ | 1.052 | $ | 1.084 | 3.0% | $ | 1.052 | $ | 1.084 | 3.0% |
| 26 | Primary Voltage | $ | 3.138 | $ | 3.233 | 3.0% | $ | 3.138 | $ | 3.233 | 3.0% |
| 27 | Transmission Voltage | $ | 25.831 | $ | 26.611 | 3.0% | $ | 25.831 | $ | 26.611 | 3.0% |
| 28 | Meter Reading | $ | 0.068 | $ | 0.038 | -44.1% | $ | 0.068 | $ | 0.038 | -44.1% |
| 29 | Billing | $ | 0.074 | $ | 0.077 | 4.1% | $ | 0.074 | $ | 0.077 | 4.1% |
| 30 | System Benefits Charge | $ | 0.00210 | $ | 0.00165 | -21.4% | $ | 0.00210 | $ | 0.00165 | -21.4% |
| 31 | Transmission Charge per kWh | | | | | | | | | | |
| 32 | per On-Peak kW | $ | 1.776 | $ | - | -100.0% | $ | 1.776 | $ | - | -100.0% |
| 33 | *Delivery Charge* | | | | | | | | | | |
| 34 | Secondary Service | | | | | | | | | | |
| 35 | On-Peak | $ | 4.951 | $ | 5.336 | 7.8% | $ | 4.951 | $ | 5.336 | 7.8% |
| 36 | Off-Peak | $ | 0.495 | $ | 0.534 | 7.9% | $ | 0.495 | $ | 0.534 | 7.9% |
| 37 | Primary Service | | | | | | | | | | |
| 38 | On-Peak | $ | 4.203 | $ | 4.530 | 7.8% | $ | 4.203 | $ | 4.530 | 7.8% |
| 39 | Off-Peak | $ | 0.420 | $ | 0.453 | 7.9% | $ | 0.420 | $ | 0.453 | 7.9% |
| 40 | Transmission Service | | | | | | | | | | |
| 41 | On-Peak | $ | 0.343 | $ | 0.370 | 7.9% | $ | 0.343 | $ | 0.370 | 7.9% |
| 42 | Off-Peak | $ | 0.034 | $ | 0.037 | 8.8% | $ | 0.034 | $ | 0.037 | 8.8% |
| 43 | Primary Substation - Military Base | | | | | | | | | | |
| 44 | On-Peak | | 1.38 | $ | 1.487 | 7.8% | | 1.38 | $ | 1.487 | 7.8% |
| 45 | Off-Peak | | 0.137 | $ | 0.148 | 8.0% | | 0.137 | $ | 0.148 | 8.0% |
| 46 | *Generation Charge* | | | | | | | | | | |
| 47 | On Peak kW | $ | 8.364 | $ | 9.015 | 7.8% | $ | 8.364 | $ | 11.270 | 34.7% |
| 48 | Off Peak kW | $ | 2.239 | $ | 2.411 | 7.7% | $ | 2.239 | $ | 2.411 | 7.7% |
| 49 | On Peak kWh | | 0.04484 | $ | 0.04584 | 2.2% | | 0.04484 | $ | 0.04182 | -6.7% |
| 50 | Off Peak kWh | | 0.03320 | $ | 0.03394 | 2.2% | | 0.03320 | $ | 0.03018 | -9.1% |
| 51 | | | | | | | | | | | |
| 52 | Delivery Discounts from Secondary Service ($/kW) | | | | | | | | | | |
| 53 | Primary Service | $ | 0.748 | $ | 0.806 | 7.8% | $ | 0.748 | $ | 0.806 | 7.8% |
| 54 | off peak | $ | 0.075 | $ | 0.081 | 8.0% | $ | 0.075 | $ | 0.081 | 8.0% |
| 55 | Transmission Service | $ | 4.608 | $ | 4.966 | 7.8% | $ | 4.608 | $ | 4.966 | 7.8% |
| 56 | off peak | $ | 0.461 | $ | 0.497 | 7.8% | $ | 0.461 | $ | 0.497 | 7.8% |
| 57 | Primary substation - Military Base | $ | 3.913 | $ | 4.217 | 7.8% | $ | 3.913 | $ | 4.217 | 7.8% |
| 58 | off peak | $ | 0.255 | $ | 0.275 | 7.9% | $ | 0.255 | $ | 0.275 | 7.9% |

1. Data Source: *APS Witness Miessner CAM_WP 13, Proof of Revenue*

EXHIBIT
ADMITTED
AECC-3

# BEFORE THE ARIZONA CORPORATION COMMISSION

| | | |
|---|---|---|
| In the Matter of the Application of Arizona | ) | |
| Public Service Company for a Hearing to | ) | |
| Determine the Fair Value of the Utility | ) | |
| Property of the Company for Ratemaking | ) | Docket No. E-01345A-11-0224 |
| Purposes, to Fix a Just and Reasonable | ) | |
| Rate of Return Thereon, to Approve Rate | ) | |
| Schedules Designed to Develop Such Return | ) | |

## Direct Testimony of Kevin C. Higgins

**on behalf of**

**Freeport-McMoRan Copper & Gold Inc. and**

**Arizonans for Electric Choice & Competition**

**Settlement Agreement**

**January 18, 2012**

# DIRECT TESTIMONY OF KEVIN C. HIGGINS

## SETTLEMENT AGREEMENT

## TABLE OF CONTENTS

# DIRECT TESTIMONY OF KEVIN C. HIGGINS

# SETTLEMENT AGREEMENT

## INTRODUCTION

**Q. Please state your name and business address.**

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

**Q. Are you the same Kevin C. Higgins who previously pre-filed direct testimony in this proceeding on behalf of Freeport-McMoRan Copper & Gold Inc. and AECC (collectively "AECC") on the topics of revenue requirement and cost of service/rate design?**

A. Yes, I am. I described my qualifications in my revenue requirements testimony. A more detailed description of my qualifications is contained in Appendix A, attached to that testimony.

## OVERVIEW AND CONCLUSIONS

**Q. What is the purpose of your settlement testimony?**

A. I am testifying in support of the Proposed Settlement Agreement ("Agreement") filed by the ACC Staff on behalf of the Agreement's Signatories on January 6, 2012. The proposed Agreement provides a comprehensive resolution of the issues in the Arizona Public Service Company ("APS") general rate case.

**Q. Were you personally involved in the negotiations that resulted in the Agreement?**

A. Yes, I participated in the negotiations on behalf of AECC.

**Q. What is your recommendation to the Commission with respect to the Agreement?**

A. I recommend that the Agreement as submitted by the Signatories be approved by the Commission. In my opinion, the Agreement produces just and reasonable rates and is in the public interest.

**Q. Does AECC support the entire Agreement?**

A. Yes. The Agreement is a package that was crafted after extensive negotiations among many parties over several weeks. AECC is recommending adoption of each provision in the Agreement as a package deal.

**Q. How is your testimony in support of the Agreement organized?**

A. First, I offer some comments on the overall Agreement. I follow that discussion with some specific comments on certain provisions of the Agreement that are of particular interest to AECC.

## OVERALL AGREEMENT

**Q. Please provide a general overview as to why you believe the Agreement is in the public interest and should be adopted.**

A. AECC is a customer group. Accordingly, I participated in the Settlement Agreement negotiations from the vantage point of customers in general, with a particular emphasis on the perspective of business customers. In providing a comprehensive resolution of the issues in the APS general rate case, the Agreement offers the following key benefits to customers:

- It results in an overall zero dollar base rate increase versus the $95.5 million base rate increase proposed by APS in its direct filing;
- It ensures a zero percent overall bill impact for the remainder of 2012 versus the $194.1 million overall rate increase proposed by APS in its direct filing – after taking account of the reset of the current Power Supply Adjustor ("PSA") credit to near zero that would have otherwise occurred upon the implementation of new rates by July 2012;
- It requires a four-year rate case stay out, pursuant to which APS agrees not to raise base rates as a result of any new general rate case filing until at least mid-2016, whereas APS would otherwise have been permitted to file a rate case after June 1, 2013 per the terms of the Settlement Agreement approved in Docket No. 01345A-08-0172;
- It includes a buy-through rate option for industrial and large commercial customers which will provide an opportunity for Arizona businesses to improve their economic health through energy cost savings – at no risk to other customers;
- It provides a narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism in lieu of the full revenue decoupling proposed by APS, while offering an opt-out rate design for residential customers who choose not to participate in the LFCR. For customers with billing demands of 400 kW or greater, the settlement agreement addresses through rate design APS's concerns over fixed cost recovery associated with energy efficiency investments.

- It provides a defined and equitable path forward for the recovery of costs associated with any acquisition by APS of Southern California Edison's share of Four Corners Units 4-5, if the Commission finds the Four Corners transaction to be prudent.
- It requires APS to file a request to reduce the System Benefit Charge ("SBC") to reflect a corresponding reduction of the decommissioning trust funding obligations collected through the SBC related to the full funding of Palo Verde Nuclear Generating Station ("PVNGS") Unit 2, which is expected to occur by the end of 2015. APS is required to make the filing in sufficient time for the reduction to occur by January 2016.

Taken as a whole, the Settlement Agreement provides meaningful protections and benefits to customers while providing APS the opportunity to earn a fair return.

Q. **In your direct testimony you challenged several aspects of APS's filing that have been included in the settlement package, such as APS's proposal to remove the sharing percentage in the PSA and the Company's proposal to include 100 percent of APS-owned solar generation in base rates, including costs above the Market Cost of Comparable Conventional Generation. Have you changed your testimony on these matters?**

A. I have not changed my opinion on these topics as isolated matters or when these topics are viewed in the context of APS's initial application. However, the overall settlement package contains enough benefits to customers that I have concluded that it is in the public interest to move forward with this entire package, including certain items with which I may disagree in isolation. Such is the nature of negotiation and compromise.

With respect to removing the sharing percentage in the PSA, I note that the Settlement Agreement requires APS to adhere to a four-year stay-out from general rate cases. I participate in general rate cases around the country; in many jurisdictions they have become annual events. A four-year stay-out is extraordinary in today's regulatory environment and conveys a very significant benefit to customers in terms of rate stability and rate certainty. APS's willingness to adhere to a stay-out of this length strongly influenced AECC's willingness to concede its litigation position on the PSA sharing percentage in this case.

In accepting a different ratemaking treatment of APS-owned solar generation than I had recommended in my direct testimony, AECC has given considerable weight to the overall zero dollar base rate increase, zero percent overall bill impact for the remainder of 2012, and the general service rate design that are included in the Settlement Agreement. Taken as a whole, these components, in combination with the rest of the Agreement, constitute a reasonable resolution to the overall case, including the ratemaking treatment of APS-owned solar generation.

## DISCUSSION OF SPECIFIC ISSUES

**Q. In your direct testimony you recommended that APS's revenue requirement for its base rates be reduced by at least $75.4 million prior to taking into account adjustments that may be offered by other parties with respect to**

**return on equity or other revenue requirement items not addressed in your testimony. Does the Settlement Agreement adequately address the revenue requirement issues you raised in your direct testimony?**

A. Yes. The Settlement Agreement reduces APS's proposed base rate increase by $95.5 million. The $75.4 million reduction recommended in my direct testimony is subsumed in this amount.

**Q. In your direct testimony you also recommended that APS's System Benefits Charge be reduced by $8.704 million per year to better reflect the reduction in decommissioning costs associated with the PVNGS life extension. Does the Settlement Agreement adequately address this issue?**

A. Yes, but in a different manner than I had proposed in my direct testimony. As I stated in my direct testimony, APS has been granted approval by the Nuclear Regulatory Commission to extend the life of PVNGS by twenty years. This life extension through the 2045-47 time frame causes two fundamental impacts on the funds that must be accrued for the purpose of nuclear decommissioning: (1) it increases the total amount of money projected to be required to complete the decommissioning, due, in large part, to the expectation that decommissioning costs will be more expensive in the future because of inflation; and (2) it extends the time for contributions to be made to the sinking fund required to pay for the decommissioning, and similarly, extends the time that interest can be earned on the balance in the sinking fund. *As a general proposition*, the net effect of these two impacts is that the annual contribution to the sinking fund necessary to pay for the decommissioning decreases significantly when the life of the facility is extended. However, this does not occur for PVNGS 2.

According to the terms of a sale/leaseback transaction that APS entered for PVNGS 2, all decommissioning costs must be paid in full by 2015. With the life of the PVNGS being extended, this special funding provision causes an increase in annual decommissioning expense for Unit 2, rather than an annual decrease, as occurs for PVNGS 1 and 3, which have decades longer to accrue the full funding needed for decommissioning with the life extension.

In my direct testimony, I recommended that the decommissioning expense charged to customers for PVNGS 2 be rolled back to the pre-life-extension annual expense of $6.047 million (total Company) from the post-life-extension annual expense of $14.968 million (total Company). I recommended that this level of expense in rates should remain in place until the 2015 expiration of the sale/leaseback terms, at which time it should be reset to assure full recovery from customers of the remaining decommissioning obligation, plus reimbursement of any funding provided by APS between 2012 and 2015 to cover the gap between the funds provided by customers and the decommissioning funding requirements of the sale/leaseback transaction.

In the Settlement Agreement the decommissioning expense charged to customers for PVNGS 2 is not rolled back; however, the Settlement Agreement expressly calls out that the PVNGS 2 decommissioning expense will drop precipitously to zero after 2015 and requires APS to file with the Commission to reset the SBC at a lower level to reflect these savings effective January 2016.

This alternative approach reasonably and adequately addresses the issue raised in my direct testimony.

**Q. In your direct testimony you recommended that the Commission reject APS's decoupling proposal for all customers. You also went on to testify that if some form of revenue decoupling is approved by the Commission, that customers with billing demands greater than 400 kW should be excluded from the program because rate design could be used to insulate APS from loss of fixed-cost recovery from energy conservation for customers of this size. Does the Settlement Agreement adequately address this issue?**

A. Yes. As I discussed above, the Settlement Agreement proposes a narrowly-tailored LFCR mechanism in lieu of revenue decoupling. At the same time it offers an opt-out rate design for residential customers who choose not to participate in the LFCR. For customers with billing demands of 400 kW or greater, the settlement agreement uses rate design to address APS's concerns over fixed cost recovery associated with energy efficiency investments, consistent with the recommendations in my direct testimony.

In my view, this compromise proposal, which relies on many features proposed by Staff in its direct testimony, is vastly superior to the full decoupling mechanism that had been proposed by the Company. First of all, any recovery of fixed costs through this mechanism is limited to fixed-costs associated with reductions attributable to energy efficiency and distributed generation; lost fixed costs attributable to other factors, such as weather and general economic conditions are excluded. This limitation addresses one of AECC's primary critiques of full revenue decoupling.

Secondly, the LFCR is limited to a portion of distribution and transmission costs and excludes costs recovered through the Basic Service Charge and 50 percent of the distribution and transmission costs that are recovered through non-generation/non-TCA demand charges; this limitation appropriately recognizes that revenues from such charges are not as sensitive to changes in usage attributable to energy efficiency as are energy charges.

Thirdly, Residential customers have the ability to opt-out of the LFCR through an alternative rate design. This provides greater flexibility to customers.

And fourthly, the Settlement Agreement appropriately recognizes that concerns over fixed-cost recovery can be adequately addressed for larger customers through rate design, specifically by setting Basic Service Charges and demand charges to align properly with APS's fixed costs.

**Q. In your direct testimony you opposed adoption of APS's proposed Environmental and Reliability Account. Does the Settlement Agreement adequately address this issue?**

A. Yes. Pursuant to the terms of the Settlement Agreement, the Company's proposal for an Environmental and Reliability Account is withdrawn. Moreover, the existing Environmental Improvement Surcharge will be revised and reset to zero on the effective date of new rates.

**Q. In your direct testimony you supported APS's proposal to implement Experimental Rate Rider AG-1. How does the Settlement Agreement deal with Rate Rider AG-1?**

A. The Settlement Agreement adopts Rate Rider AG-1, as refined by the Stipulating Parties in the settlement negotiations. Rate Rider AG-1 allows qualifying customers with aggregated monthly demands of 10 MW or more to obtain alternative sources of generation to serve their full power requirements.

APS will purchase and manage the generation on behalf of the customer for a management fee of $0.0006 per kWh.

The settlement discussions provided an opportunity for interested parties to fill in the details to make AG-1 workable while adhering to the original "buy-through" concept proposed by APS; in a buy-through transaction, in contrast to direct access, the utility acts as the middleman between customer and the market.

**Q. What is your assessment of Rate Rider AG-1?**

A. Rate Rider AG-1 is a very customer-friendly innovation. It has the potential to enable Arizona businesses to improve their economic health through energy cost savings – at no risk to other customers. Because it is an experimental rate rider, participation will be limited to 200 MW. Consequently, it will be necessary to develop a fair and efficient lottery process to use in the event AG-1 becomes over-subscribed.

**Q. Do you believe that Experimental Rate Rider AG-1 can be a good substitute for a policy of reinstating direct access service in Arizona?**

A. No, I do not see that as its purpose. AECC continues to advocate for reactivation of direct access service in Arizona. However, that issue is outside the purview of this proceeding. In the meantime, Experimental Rate Rider AG-1 can provide substantial benefits to customers through the buy-through option.

**Q. In your direct testimony you objected to APS's proposed spread of rates. Does the Settlement Agreement adequately address this issue?**

A. Yes. The zero base rate increase – combined with the zero percent overall bill impact for the remainder of 2012 – allays my concerns regarding the spread of rates. Moreover, the rate impacts from the eventual reset of the PSA credit in February 2013 is reasonably mitigated through the equalization of the percentage bill impact across General Service customers.

The Settlement Agreement also provides for an adjustment rider to recover the rate base and non-PSA related expenses associated with any acquisition by APS of Southern California Edison's share of Four Corners Units 4-5 on an equal percentage basis across all rate schedules. This provision offers a defined and equitable path forward for recovery of these potential costs if the Commission finds the Four Corners transaction to be prudent.

**Q. Does this conclude your settlement testimony?**

A. Yes, it does.

EXHIBIT
ADMITTED
AECC-4

# BEFORE THE ARIZONA CORPORATION COMMISSION

| | |
|---|---|
| In the Matter of the Application of Arizona )<br>Public Service Company for a Hearing to )<br>Determine the Fair Value of the Utility )<br>Property of the Company for Ratemaking )<br>Purposes, to Fix a Just and Reasonable )<br>Rate of Return Thereon, to Approve Rate )<br>Schedules Designed to Develop Such Return) | Docket No. E-01345A-11-0224 |

**Responsive Testimony of Kevin C. Higgins**

**on behalf of**

**Freeport-McMoRan Copper & Gold Inc. and**

**Arizonans for Electric Choice & Competition**

**Settlement Agreement**

**January 25, 2012**

# RESPONSIVE TESTIMONY OF KEVIN C. HIGGINS

## SETTLEMENT AGREEMENT

## TABLE OF CONTENTS

**RESPONSIVE TESTIMONY OF KEVIN C. HIGGINS**

**SETTLEMENT AGREEMENT**

## INTRODUCTION

**Q. Please state your name and business address.**

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

**Q. Are you the same Kevin C. Higgins who previously filed direct testimony in support of the Settlement Agreement in the Arizona Public Service Company ("APS") general rate case on behalf of Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition (collectively "AECC"), and also filed direct testimony on the topics of revenue requirement and cost of service/rate design in this proceeding?**

A. Yes, I am. I described my qualifications in my revenue requirements testimony. A more detailed description of my qualifications is contained in Appendix A, attached to that testimony.

## OVERVIEW AND CONCLUSIONS

**Q. What is the purpose of your responsive testimony in this phase of the proceeding?**

A. I am responding to the testimonies in partial opposition to the proposed Settlement Agreement ("Agreement") submitted by Ralph Cavanagh on behalf of the Natural Resources Defense Council and Jeff Schlegel on behalf the Southwest Energy Efficiency Project.

**Q. Please summarize your responsive testimony.**

A. I recommend that the Commission reject each of the proposed changes to the Settlement Agreement advocated by Mr. Cavanagh and Mr. Schlegel. In particular, I recommend that the Commission reject the attempt by Messrs. Cavanagh and Schlegel to impose revenue decoupling on a utility that does not need it and customers that clearly do not want it.

## LOST FIXED-COST RECOVERY VERSUS DECOUPLING

**Q. What do Mr. Cavanagh and Mr. Schlegel recommend with respect to the Lost Fixed Cost Recovery ("LFCR") mechanism proposed in the Agreement?**

A. Both Mr. Cavanagh and Mr. Schlegel recommend that the LFCR mechanism negotiated by the Stipulating Parties be rejected in favor of full revenue decoupling.

**Q. What is your response to their position?**

A. APS is required to meet a Commission-mandated energy-efficiency standard. The stated objective of revenue decoupling is to remove a utility's financial disincentive to support energy efficiency, and by extension, Commission-required energy efficiency requirements. Through its support of the Settlement Agreement, APS has concluded that the combination of LFCR mechanism and rate design improvements in the Agreement sufficiently removes the Company's financial disincentives to meet the Commission's standards.[1] By itself, this is sufficient grounds to refrain from imposing decoupling: if the entity

[1] See for example, direct settlement testimony of Leland R. Snook, pp. 3-7.

that decoupling is intended to "protect" concludes that decoupling is not necessary, there is no good reason to impose decoupling against the will of customers.

Representatives of a wide spectrum of customer interests – from small customers to large customers – RUCO, AARP, and AECC – and individual customers such as FEA, Kroger, and Wal-Mart – have each opposed the full revenue decoupling advocated by Messrs. Cavanagh and Schlegel. These customer groups have signed on in support of the LFCR/Rate Design alternative that was largely advanced by Staff in its direct testimony and more fully developed in the negotiated Agreement.

Revenue decoupling is not an end in itself. Just the opposite is true: revenue decoupling is intended to address a very specific problem – utility financial disincentives – and winds up capturing many unrelated effects, such as weather, economic conditions, and changes in customer class composition. If the specific problem that revenue decoupling is intended to address is adequately addressed through an alternative approach – and the utility, its customers, and the regulatory Staff agree on that alternative approach – then the overly-broad and widely-opposed decoupling mechanism should certainly be avoided.

Both Mr. Cavanagh and Mr. Schlegel appear to be second-guessing APS's assessment that the Company does not need the added revenue protection of full decoupling to comply with the Commission's Rules on energy efficiency. For example, Mr. Cavanagh expresses concern that the "Settlement Agreement does not make APS whole for lost fixed costs even from those sales that APS is judged to have lost as a result of its programs."[2] In my experience, APS is fully capable of assessing its own best interests. I believe it would be unwise for the Commission to override the Settlement Agreement in favor of Mr. Cavanagh's and Mr. Schlegel's insistence that APS be afforded protections it does not need and which customers do not wish to extend.

**Q. On page 7 of his testimony partially opposing the Settlement, Mr. Cavanagh indicates his opposition to addressing utility financial disincentives through rate design. How do you respond?**

A. Mr. Cavanagh is critical of the residential "opt out" proposal which would grant residential customers the freedom to choose an alternative rate design. He is also critical of utilizing rate design to exclude large General Service customers from the LFCR mechanism, complaining that "the Proposed Settlement proposes the same kind of rate design change for large customers as a rationale for excusing them from contributing to the lost fixed-cost recovery mechanism." In making this statement, Mr. Cavanagh misapprehends the role of rate design in resolving the utility's financial disincentive that is at the center of the decoupling debate: when fixed costs are removed from the volumetric energy charge through rate design, *there is no extra contribution to fixed-cost recovery that needs to be made*. Mr. Cavanagh's inference that larger customers would somehow be "excused" from making a contribution to fixed cost recovery is groundless. Rather, Mr. Cavanagh appears to have lost touch with the goal of removing the utility's financial disincentives to support energy efficiency – which the

---

[2] Testimony of Ralph Cavanagh in Partial Opposition to the Proposed Settlement Agreement, p. 8, lines 1-3.

Settlement "opt out" and rate design for larger customers accomplish – in favor of advocacy for decoupling as an end in itself.

**Q. On pages 3-4 of his testimony, Mr. Cavanagh is critical of opponents of decoupling for ignoring the Commission's Policy Statement on Decoupling. How do you respond to this criticism?**

A. In my direct testimony I not only referenced the Commission's Policy Statement on Decoupling, I quoted from it – Policy Statement 11 to be exact, which provides that:

> Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes. Utilities should address any proposed distinct treatments and justify why certain customer classes may merit different treatment.

This is a section of the Policy Statement that Mr. Cavanagh overlooks in his criticism of the Settlement Agreement's use of rate design to resolve the issue of utility financial disincentives. The Commission's Policy Statement clearly provides the flexibility to develop a rate design approach for addressing utility financial disincentives, as the Stipulating Parties have done.

<u>**RESPONSE TO ADDITIONAL ISSUES RAISED BY MR. SCHLEGEL**</u>

**Q. On pages 6 and 7 of his Settlement testimony, Mr. Schlegel recommends that the proposed four-year rate case stay out be shortened to three years. What is your response to this recommended change?**

A. I strongly oppose this proposed change. The rate case stay-out is an unequivocal benefit to customers and a major achievement of the negotiated Agreement. Shortening it is certain to bring higher rates sooner to Arizona customers and would deprive customers of the full benefit of their bargain in this Agreement.

**Q. On page 10 of his testimony, Mr. Schlegel proposes to shift $70 million in DSM funding from the DSM Adjustor to base rates. Do you support this change?**

A. Absolutely not. Not only is this change contrary to the Settlement Agreement, such a shift would reduce the visibility of the DSM program costs by burying them in base rates. Healthy public discourse on the size of the funding requirements for these programs is better assured if the cost recovery is transparent and fully disclosed in the DSM Adjustor rate.

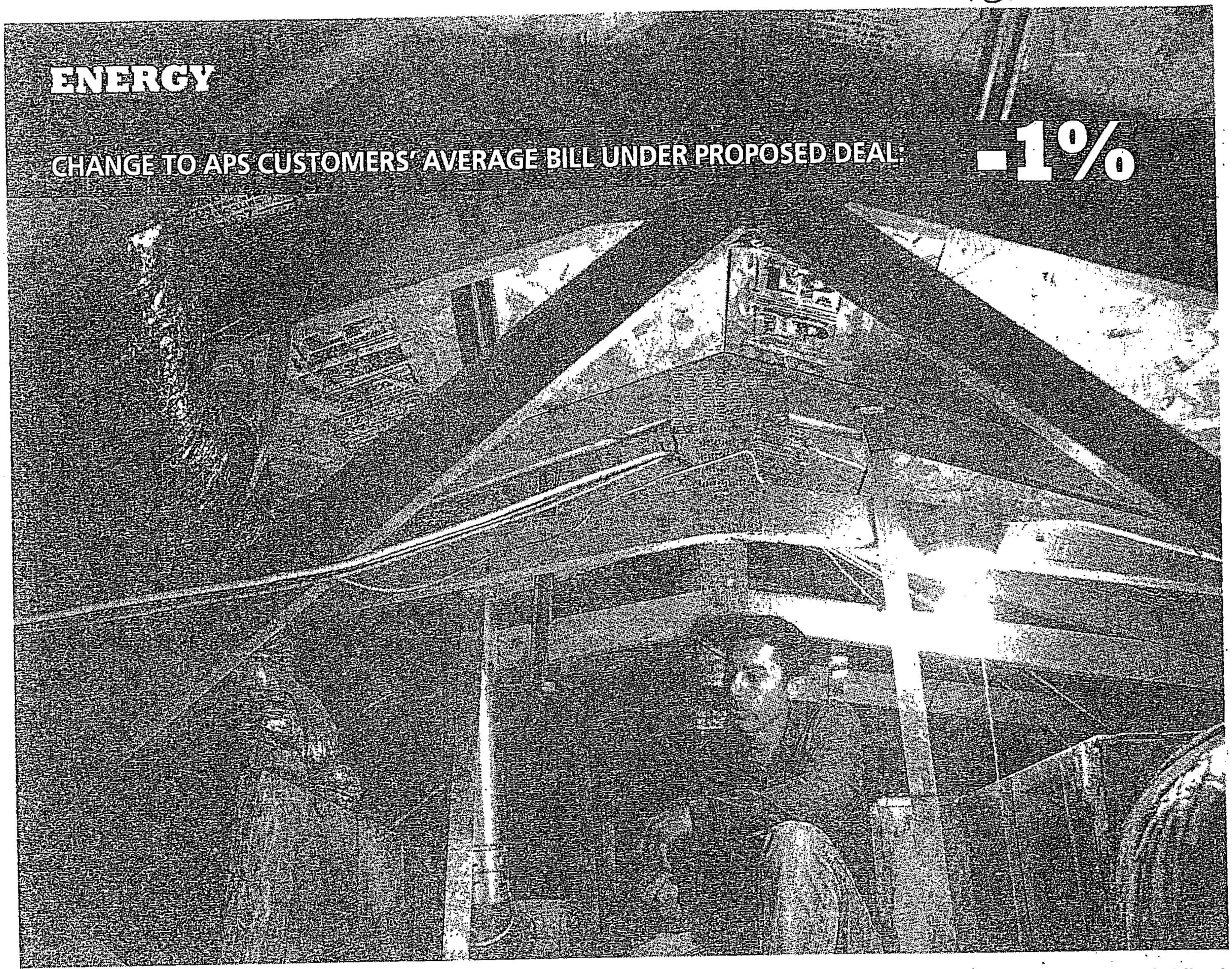
**Q. In summary, do you support any of the changes to the Settlement Agreement advocated by Mr. Schlegel and Mr. Cavanagh?**

A. No, I do not.

**Q. Does this conclude your responsive testimony?**

A. Yes, it does.

The Arizona Republic
01/12/12




Nick Mathis, a project manager with Pro Energy Consultants, checks the weatherization work in a Phoenix home, which was subsidized with a rebate from Arizona Public Service Co. The utility's customers may soon see a 1 percent drop in their bills. MARK HENLE/THE REPUBLIC

# APS customers likely to see bills decrease

## Natural-gas prices; consumer pressure reverse planned 6.6% rate hike

EXHIBIT
N-1
ADMITTED

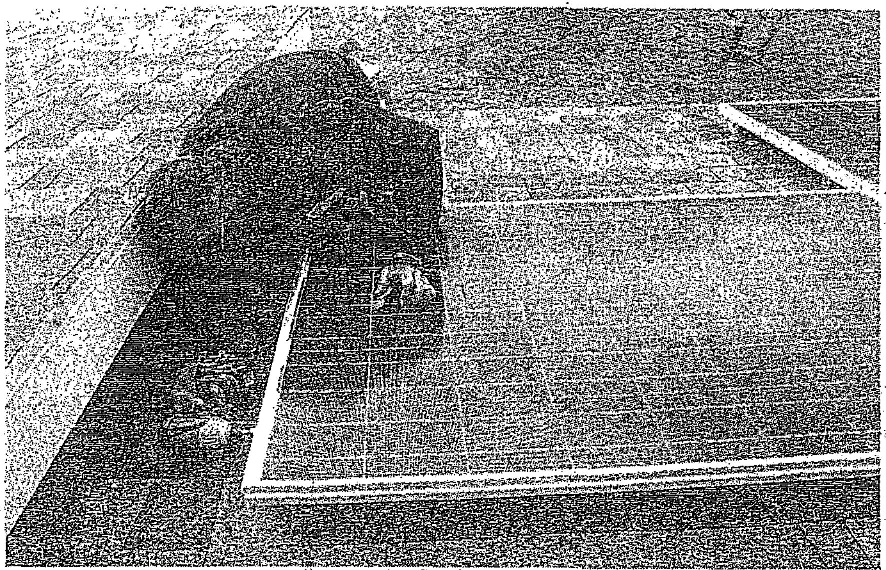
By Ryan Randazzo
The Republic | azcentral.com

If utility regulators approve, Arizona Public Service Co. customers could see a 1 percent drop in their average bill this year and no base-rate increases until 2016.

APS went to state regulators in June asking for a 6.6 percent rate increase, but pressure from consumer groups and low natural-gas prices helped seal a deal more favorable to ratepayers. The state's largest utility and 20 large customers, consumer groups and other stakeholders have signed an agreement, which must be voted on by the Arizona Corporation Commission, that would hold rates steady for at least a year.

During negotiations, APS agreed to major changes to its rate request in the face of criticism from groups such as AARP. In return, APS would receive one of its key goals: financial incentives for the company to promote

See APS, Page A6



Brian Dugan of Harmon Electric installs solar panels in Phoenix. Financial incentives are in the works to help APS foster energy efficiency. DEIRDRE HAMILL/THE REPUBLIC

## APS

Continued from Page A1

energy efficiency.

Another key ingredient in the settlement is that natural-gas prices are at their lowest levels in a decade and were low for all of 2011, according to a report from the U.S. Energy Information Administration.

A portion of utility bills is tied to natural-gas prices and is adjusted annually to reflect market prices.

"We are benefiting from (natural-gas power plant) fuel prices coming down," said Jeff Guldner, APS vice president of regulation. "This is happening all around the country."

If the commission approves the deal, residential customers will see an immediate decrease of about 1 percent in their average monthly bill.

In addition, APS cannot request another rate hike until 2015, and it cannot take effect until 2016.

But customers won't get away untouched. Several components of their bills will increase starting next year, but not in the one large increase that APS had requested.

The agreement calls for several billing tweaks during the next four years, including:

» Extending a credit that averages about $5 a month for residential customers for another year, when it will reset.

The credit compensates for money APS overcollected for natural gas in the past year, but it likely will turn to a charge with the reset.

The reset likely will result in a 2.5 percent bill increase next year, depending on natural-gas prices between now and 2013.

» Potentially asking customers to help pay for coal generators. The settlement would allow APS to proceed with a separate request to buy a larger stake in two generators at the Four Corners Power Plant and shut three of its old, heavily polluting generators there. If approved, the purchase could mean a 3 percent rate hike on customers in 2013.

» Granting authority to APS to raise bills a maximum 1 percent a year starting in 2013 to compensate for energy sales it loses by promoting energy efficiency and rooftop solar panels.

### Costs of efficiency

Utilities typically increase profits by selling more electricity. But now, regulators are asking utilities to be promote efficiency, which means they burn less fuel and generate less pollution.

The most contentious part of the APS rate request was its proposal to "decouple" its rates.

Decoupling is an industry term for a fee utilities can charge to pay for their fixed costs, such as power lines and transformers, that they must maintain even as they sell less electricity to customers when they subsidize efficient air-conditioners and attic insulation or duct sealing.

Utilities seek to decouple their revenues from the volume of electricity they sell so that they can remain profitable without increasing the kilowatt-hours they sell.

The Corporation Commission is requiring utilities to reduce their energy sales by 22 percent in 2020 through increased efficiency, which would be devastating to APS finances without a change in rates, Guldner said.

APS originally asked regulators to approve a fee that would help make up for the revenue it loses when it helps customers save energy by helping them buy more efficient appliances.

But AARP and the Residential Utility Consumers Office, a state department created by the Legislature to represent the public at utility-rate hearings, protested decoupling.

They argued that APS would insulate itself from the business risks of mild weather or blackouts that reduce the volume of electricity it sold because the company could raise its prices to make up for those losses in the name of energy efficiency.

"There was an immense amount of pushback from consumer groups," Guldner said.

Corporation commissioners approved a decoupling provision for Southwest Gas in December that could mean an additional $1.50 a month on residential bills, but that vote was split 3-2 among the elected officials.

APS, which was negotiating with its stakeholders at that point, backed off its decoupling proposal in favor of a fee.

The fee, called the "lost fixed-cost recovery" mechanism, would be a strict calculation of how much electricity APS is helping customers save when it gives them rebates for things like more efficient pool pumps or duct sealing.

When APS funds those programs, it saves the cost of building more power plants, but it still must pay to maintain the power lines, transformers and other equipment to get electricity to customers.

The fee would ensure that APS is covering those expenses even as it encourages customers to save power or to generate their own power with rooftop solar panels.

The fee is capped at 1 percent a year and would not be charged until April 2013. APS estimates the initial fee would be about a 0.2 percent increase in 2013, based on energy-use and efficiency projections.

A 1 percent cap on the increases would mean it could not be more than about $1.30 a month on the average residential customer.

## Some holdouts

Environmental groups such as the Natural Resources Defense Council wanted full decoupling and have not agreed on the settlement.

The council filed testimony in the rate case in November stating that, without decoupling, energy-conservation measures by APS "create significant disincentives for the utility with serious adverse financial impacts."

The Southwest Energy Efficiency Project, or SWEEP, did not sign the settlement because decoupling was not included as an option, but its Arizona representative, Jeff Schlegel, said the fee proposed in the settlement is better than nothing.

"Energy efficiency is the best and least-cost resource for Arizona, and this settlement didn't go far enough in terms of supporting it," Schlegel said. "We thought it was important for the commission to also consider decoupling."

Both groups can continue to present their issues to the regulators, but their consent isn't required for the deal to be approved.

But consumer groups are happy with the deal, including some of the most ardent critics of decoupling, such as AARP.

"This is not the full decoupling that Southwest Gas got," said Stephen Jennings, an AARP associate state director. "This one is much more narrow and much more directly tied to energy-efficiency efforts. (They can't just raise rates) for any reason they lose money."

He said that AARP did not get everything its leaders wanted from the negotiations but that he is happy with the outcome.

"These settlements are compromises," he said. "Nobody gets everything they wanted. We are going to let our membership know that any rate increases that occur because of this are less than they would have been if we had not been involved."

APS would be allowed to charge only for the fixed costs that it lost because of energy-efficiency programs that are approved by regulators, which means APS would have to track those programs and their savings closely.

"Now, (tracking those savings) becomes a very big issue," Guldner said.

The proposal also would allow APS to charge for the fixed costs of serving customers who generate much of their own electricity with rooftop solar panels.

APS still must serve those solar customers with power lines and other equipment to get electricity to them at night, but it earns less of its fixed costs from them because they buy fewer kilowatt-hours of electricity.

"Some of that is good," Guldner said of customers using solar.

"If we didn't have customers putting solar on their roofs, we'd be out building natural-gas plants and charging all of our customers for those (power plants) and the natural gas."

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS:
Gary Pierce, Chairman
Bob Stump
Sandra D. Kennedy
Paul Newman
Brenda Burns

EXHIBIT
FEA - 1
ADMITTED

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTLITY 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-11-0224 |

**PREFILED TESTIMONY**

**OF**

**LARRY BLANK**

**ON BEHALF OF**

**THE FEDERAL EXECUTIVE AGENCIES**

**NOVEMBER 18, 2011**

FEA Ex: 1

## I. IDENTIFICATION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Larry Blank. My business address is Tahoeconomics, LLC, 2533 North Carson St., Suite 3624, Carson City, NV 89706. My email address is LB@tahoeconomics.com.

**Q. WHERE ARE YOU EMPLOYED?**

A. I am currently an Associate Professor of Economics and the Associate Director with the Center for Public Utilities in the College of Business at New Mexico State University ("NMSU"). For the purposes of this proceeding, I am engaged through *TAHOEconomics*, LLC, ("Tahoe"), a Nevada-registered consulting firm I founded in 1999, and for which I serve as principal. Tahoe specializes in most policy and ratemaking facets of regulated utility industries. The expert opinions expressed herein are my own and nothing in this testimony necessarily reflects the opinions of NMSU.

**Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR BACKGROUND AS IT IS RELEVANT TO THIS TESTIMONY.**

A. I have served the public in various capacities for over twenty-five (25) years. I received a Ph.D. in Economics from The University of Tennessee in 1994, specializing in Industrial Organization & Public Policy (including regulatory policy), Econometrics, and Finance. I previously served as an Economist with the National Regulatory Research Institute ("NRRI") at the Ohio State University and later as the Manager of Regulatory Policy & Market Analysis at the Nevada Public Utilities Commission. My division's responsibilities at the Nevada commission included participation in several rulemaking workshops, hearings and rates analysis for all regulated utilities in that jurisdiction as well as expert witness testimony on the same. As a consultant, I have served a variety of clients including regulatory agencies, utility customers, utility companies, and the U.S. Department of Energy as the Project Director for technical assistance to the Energy Regulatory Commission in the Philippines. I have served as an expert witness and/or advisor in over 150 rate cases and rulemakings of various types and filed written testimony in the following utility regulatory commission jurisdictions: Arizona, Alaska, Arkansas, Colorado, Montana, Nevada, New Mexico, Texas, and the Federal Energy Regulatory Commission. I also teach advanced graduate utility regulation at NMSU, and I help deliver nationally-recognized rate-case training programs offered by the Center for Public Utilities at NMSU, which are attended by regulatory professionals from across the United States and are endorsed by the National Association of Regulatory Utility Commissioners ("NARUC").

## II. <u>PURPOSE AND SUMMARY</u>

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

A. I am testifying on behalf of the Federal Executive Agencies ("FEA") in response to two proposals in the revenue requirements phase of the Arizona Public Service Company ("APS" or the "Company") application to adjust retail service rates. These proposals are found in the APS testimonies of Mr. Leland Snook and Mr. Zachary Fryer.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. First, the decoupling mechanism proposed by APS, the Efficiency and Infrastructure Account ("EIA") Mechanism, should be rejected because: (1) its proposed design would result in over-correction for fixed cost recovery due to changes in kWh sales; (2) it fails to remove the large amount of fixed costs recovered through the fixed monthly basic charges and the demand charges; and, (3) it does not account for the significant differences in rate design across rate classes as well as the differences in level of energy efficiency programs across rate classes. As a result, the EIA will shift fixed cost recovery between rate classes. This shifting of fixed cost recovery between rate classes is unjust and unreasonable.

Second, the Company's proposal to move $44,911,000 out of the Renewable Energy Standard Surcharge ("RES Surcharge") into the base rates should be rejected. First, this proposal will greatly reduce the transparency on how much customers are paying for the utility to have renewable energy on the system and for the cost of the special policy mandates required by the Renewable Energy Standard ("RES"). Second, there is precedence in Arizona for monthly per customer RES Surcharge Limits (or "Caps") and those monthly limits would now be partially eliminated under the APS proposal to move almost half the annual renewable energy costs into the base rates. The levels of these Surcharge Caps have already been decided and should continue to be litigated as part of the Company's annual application for approval of its renewable energy standard and tariff implementation plans. Third, when it comes to the Federal Department of Defense ("DoD") customers (e.g., Luke Air Force Base), these customers are required to obtain 25% of their total electricity usage from renewable resources by

2025 (10 U.S.C.§ 2911) and these customers cannot take advantage of the Arizona RES mandates on APS in meeting the 25% Federal requirement.

## III. APS'S PROPOSED EFFICIENCY AND INFRASTRUCTURE ACCOUNT (EIA) MECHANISM

**Q. IN GENERAL, WHAT IS THE EIA MECHANISM?**

A. APS's proposed Efficiency and Infrastructure Account ("EIA") Mechanism is a revenue-per-customer decoupling mechanism that attempts to mitigate utility financial disincentives to develop utility-sponsored energy efficiency programs. In general, revenue decoupling mechanisms break the linkage (i.e., "decouples") revenues from kilowatt-hour (kWh) sales.

**Q. WHAT IS THE SOURCE OF THE FINANCIAL DISINCENTIVES?**

A. The objective of energy efficiency ("EE") programs is to reduce kWh sales. In between rate cases, when base rates are fixed, reductions in kWh sales may adversely impact recovery of fixed costs, which in turn will adversely impact investment returns. This adverse effect of reduced kWh sales occurs because, typically, utility rate structures place a large dependence on the energy charge ($/kWh) for fixed-cost recovery. For illustrative purposes only, suppose the energy charge is $0.0962 per kWh and that $0.0337 of this charge recovers variable (energy-related) costs while $0.0625 recovers fixed costs. For every kWh reduction in sales from adjusted test-year levels due to EE programs, the utility loses $0.0962 in revenue but costs only decrease by $0.0337. Fixed costs do not vary with kWh sales, so in this stylized example, the utility loses $0.0625 in fixed-cost recovery from the single kWh reduction in sales.

**Q. WHAT ARE FIXED COST?**

A. Fixed costs are those costs that do not vary with the amount of kWh produced and sold while variable ("energy-related") costs are those costs that do vary with kWh. Examples of fixed costs in revenue requirements are annual depreciation expense on plant in service ("return of investment"), certain taxes, most operations and maintenance expenses, administration and general expenses and return dollars on investment for interest payments and a fair profit (determined from last rate case). The best examples of variable costs are fuel expenses for generation and some variable generation operations and maintenance such as lubricants and pollution abatement scrubbing agents.

**Q. YOU SAID THAT THE SOURCE OF THE FINANCIAL DISINCENTIVE IS A DEPENDENCE ON THE ENERGY CHARGE FOR FIXED-COST RECOVERY. IS THE ENERGY CHARGE THE ONLY RATE ELEMENT USED TO RECOVER FIXED COSTS?**

A. No. The basic service charge (i.e., the "fixed customer charge") yields a fixed stream of revenue per customer, which contributes to the recovery of fixed costs. Also, revenue collected from demand charges ($/kW of monthly billing demand) contribute to the recovery of fixed costs. Because customers' monthly billing demands are not completely fixed from month to month, revenue collected per customer from demand charges – unlike revenue collected per customer from customer charges – is not completely fixed. However, revenue collected from demand charges is significantly less variable than revenue collected from energy charges. According to APS witness Leland Snook:

> "Under traditional ratemaking, the vast majority of [fixed] costs is collected through usage-based (or "volumetric") rates [i.e., energy charges]. In the 2010

Test Year, for residential customers APS collected approximately 27% of its fixed costs through a fixed charge (the basic service charge and kilowatt (kW) demand charges), while the remaining 73% was collected through kilowatt-hour ("kWh") rates. For commercial customers the percentages were 34% through fixed charges (basic service and kW charges) and 66% through kWh charges. Basic service charges alone were only approximately 16% for both residential and commercial customers." (Snook Direct Testimony, p. 3, lines 10 – 19)

**Q. IS APS'S DEPENDENCE ON THE ENERGY CHARGE FOR FIXED COST RECOVERY UNUSUAL?**

A. Not in my experience. Consumer advocates for residential and small commercial customers tend to dislike large fixed customer charges because it causes the bills of below-average usage customers to increase and, typically, these customers do not have demand meters so that a kW demand charge cannot be implemented. Therefore, the energy charge must pick up most of the load in terms of fixed-cost recovery causing the fixed costs paid by customers to closely track kWh usage.

**Q. COULD YOU ELABORATE A LITTLE MORE ON HOW APS'S PROPOSED EIA MECHANISM WORKS?**

A. From the test-year data, APS calculates the allowed total fixed cost per customer (for each rate class). These allowed total fixed costs are also expressed on a per kWh (for each rate class) from the adjusted test-year annual kWh values. For some future year, the allowed total fixed costs are calculated by multiplying that future year's actual number of customers by the test-year allowed fixed cost per customer. The actual fixed costs value for some future year are calculated by multiplying that future year's actual kWh sales by the test-year allowed fixed costs per kWh. After these calculations are summed over all rate classes, the difference between the future year's aggregate allowed fixed costs and the future year's aggregate actual fixed costs is that year's "EIA dollar adjustment." This total dollar adjustment is divided by the year's actual revenues to obtain an "EIA percent adjustment." The percent adjustment is then applied across the board to all customers in all rate classes.

**Q. IN YOUR OPINION, ARE THERE ANY FLAWS IN PROPOSED EIA MECHANISM?**

A. Yes. The proposed EIA mechanism over-corrects for the lost recovery to fixed costs because it does not properly account for the recovery of fixed costs-through rate elements other than the energy charge. In order to see this, consider the hypothetical illustrative example found in Table 1, where sales in some future year have decreased by 10% from the test-year level. For simplicity, I have assumed that the future year has the same number of customers as in the test year from the last rate case; therefore, the fixed costs per customer are the same and the "allowed fixed costs" in the EIA mechanism is the same for both years – equal to $75,000,000 in Line [3] of Table 1. Also for simplicity, I assume there is only one rate class, which only has two rate elements determined from the last rate case: an energy charge and a fixed monthly customer charge. Under the APS method, the actual fixed costs for the future year is calculated in the following two steps: (1) divide the allowed fixed costs from the last rate case ($75,000,000) by the test-year kWh from the last rate case (900,000,000); and then, (2) multiply the resulting test-year allowed fixed costs per kWh ($0.0833) by the future year's actual kWh (810,000,000), which yields the "actual fixed costs" for the future year ($67,500,000 from Line [8] in the table). Finally, the difference between the allowed fixed costs ($75,000,000) and the actual fixed costs ($67,500,000) illustrates the APS-EIA method's determination of the future year's lost recovery of fixed costs (i.e., the "EIA dollar adjustment") shown from Line [11] in the table as $7,500,000.

| Table 1: APS Method vs. Corrected Method (hypothetical example) | | | |
|---|---|---|---|
| Line | Item | From Last Rate Case | Future Year |
| [1] | Actual kWh | 900,000,000 | 810,000,000 |
| [2] | Actual Customers | 75,000 | 75,000 |
| [3] | Allowed Total Fixed Costs (TFC) | $75,000,000 | $75,000,000 |
| [4] | TFC Recovered by Fixed Customer Charge | $18,750,000 | $18,750,000 |
| [5] | TFC Recovered by Energy Charge | $56,250,000 | |
| [6] | TFC per kWh (test-year from last rate case: [3]/[1]) | $0.0833 | $0.0833 |
| [7] | TFC Recovered by Energy Charge per kWh (test-year from last rate case: [5]/[1]) | $0.0625 | $0.0625 |
| [8] | Actual TFC Recovery-APS Method ($0.0833*[1]) | $75,000,000 | $67,500,000 |
| [9] | Actual TFC Recovery by the Energy Charge ($0.0625*[1]) | | $50,625,000 |
| [10] | Actual TFC Recovery-Corrected Method ([4] + [9]) | | $69,375,000 |
| [11] | Lost Recovery of Fixed Cost-APS Method ([3] - [8]) | | $7,500,000 |
| [12] | Lost Recovery of Fixed Cost-Corrected Method ([3] - [10]) | | $5,625,000 |

The APS-EIA method, however, overestimates the lost recovery of fixed costs. The illustrative example in Table 1 shows that of the $75,000,000 in allowed annual fixed costs, $18,750,000 is recovered from the fixed monthly customer charge (determined in the last rate case) and $0.0625 per kWh is recovered from the energy charge (also determined from the last rate case). For example, if the energy charge was determined to be, say, $0.0962 per kWh – and if average variable (energy) costs are $0.0337 per kWh – then $0.0625 per kWh ($0.0962 – $0.0337) of the energy charge is used for recovering fixed costs. For every kWh reduction in sales (from adjusted test-year levels) the utility loses $0.0962 in revenue but costs only decreases by $0.0337. Fixed costs do not vary with kWh sales, so in this stylized example, the utility loses $0.0625 in fixed-cost recovery from the single kWh reduction in sales. Put another way, and as illustrated in Table 1, if the future year's actual annual kWh decreases to 810,000,000 kWh, actual fixed cost recovery is equal to ($0.0625)*(810,000,000) = $50,625,000 from the energy charge (Line [9]) PLUS the $18,750,000 from the fixed monthly customer charge (Line [4]). Therefore, in total, the future year's actual fixed cost recovery is $69,375,000 from Line [10] in Table 1. As a result, the "Corrected Method" yields lost fixed cost recovery of $5,626,000 from Line [12] (as compared to the APS-EIA Method of $7,500,000 from Line [11]).

**Q. WILL THE OVER-CORRECTION FOR FIXED COST RECOVERY BE EVEN MORE PRONOUNCED FOR THOSE RATE CLASSES THAT HAVE DEMAND CHARGES?**

A. Yes. Because the lost contribution to fixed costs in the APS-proposed decoupling mechanism includes all fixed costs and not just the amounts recovered through the energy charges, the level of lost contribution to fixed costs in the calculation includes both the customer charge-related costs and the demand charge-related costs. Therefore, the over-correction caused by its design will be even more pronounced for those customer classes with demand charges, which recovers a portion of fixed costs.

**Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE APS-EIA MECHANISM?**

A. Yes. My additional concern with the EIA mechanism centers on the fact that the EIA adjustment is a flat across-the-board percent adjustment to all customers in all rate classes. As pointed out in Company witness Leland Snook's direct testimony (pp. 17 – 18) large customers, particularly those served under rate schedules E-34 and E-35, have significantly less of the allocated fixed cost recovered through the energy charge. Therefore, to include these large customers in a group with customers that have an extremely large share of the fixed costs recovered from the energy charge would – given that the EIA percent adjustment is an across-the-board flat adjustment for all rate classes – lead to these large customers paying for more than their allocated share of fixed costs from the last rate case. This shifting of fixed cost recovery across rate classes is unjust and unreasonable and will lead to discriminatory rates. If the Commission decides that the EIA adjustment is appropriate for residential customers, one alternative is to remove these large customers from the pool of rate classes to which the EIA adjustment applies. Company witness Leland Snook actually suggests this alternative in his direct testimony. (pp. 17 – 18).

**Q. WHAT ARE YOUR RECOMMENDATIONS ON THE APS REVENUE DECOUPLING PROPOSAL?**

**A.** First, I recommend that the Commission reject the decoupling mechanism proposed by APS. Second, revenue decoupling should be done by rate class for all the reasons stated above. Third, the target fixed cost recovery should be limited to only those fixed costs included in the energy charge calculation during the general rate case. Again, as pointed out in Company witness Leland Snook's direct testimony (pp. 17 – 18), an alternative is to remove the large customers from the pool of rate classes to which the EIA adjustment applies.

## IV. RENEWABLE ENERGY COSTS AND SURCHARGE

**Q. HAS APS PROPOSED TO MOVE RENEWABLE ENERGY COSTS AWAY FROM THE SURCHARGE AND INTO THE BASE RATES?**

A. Yes. As stated by APS witness Mr. Fryer, the Company is proposing to move $44,911,000 out of the Renewable Energy Standard Surcharge ("RES Surcharge") into the base rates [Fryer Direct at p. 2, lines 26-27].

**Q. DO YOU HAVE ANY CONCERNS WITH THIS PROPOSAL?**

A. Yes. First, this will greatly reduce the transparency on how much customers are paying for the utility to have renewable energy on the system and the cost of the special policy mandates required by the Renewable Energy Standard ("RES"). Second, there is precedence in Arizona for monthly per customer RES Surcharge Limits (or "Caps") and those monthly limits would now be partially eliminated under the APS proposal to move almost half the annual renewable energy costs into the base rates. The levels of these Surcharge Caps have already been decided and should continue to be reviewed as part of the Company's annual application for approval of its renewable energy standard and tariff implementation plans (see e.g., Decision No. 72022). The Company's proposal on this matter would effectively negate past Commission decisions and precedence insofar as the per customer Surcharge Limits are concerned. Third, when it comes to the Federal

Department of Defense customers (e.g., Luke Air Force Base), these customers are required to obtain 25% of their total electricity usage from renewable resources by 2025. (10 U.S.C.§ 2911) Military customers do not include renewable energy that is part of the APS generation fleet to meet the 25% DoD requirement. Instead, the DoD must develop additional renewable energy sources to meet this requirement. Therefore, the RES Surcharge Limit or Cap per customer service line helps protect these Federal customers from paying more than a reasonable level in addition to its own mandates to procure renewable energy above and beyond those of APS.

**Q. WHAT IS YOUR RECOMMENDATION ON THE APS PROPOSAL TO MOVE $44.9 MILLION OUT OF THE RES SURCHARGE AND INTO BASE RATES?**

A. Based on the concerns I express above, I recommend that the Commission reject this proposal and retain these annual costs in the RES Surcharge. The levels of these Surcharge Caps have already been decided and should continue to be litigated as part of the Company's annual application for approval of its renewable energy standard and tariff implementation plans (see e.g., Decision No. 72022).

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

A. Yes.

EXHIBIT
FEA-2
ADMITTED

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS:
Gary Pierce, Chairman
Bob Stump
Sandra D. Kennedy
Paul Newman
Brenda Burns

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTLITY 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-11-0224 |

**PREFILED TESTIMONY**

**OF**

**LARRY BLANK**

**ON BEHALF OF**

**THE FEDERAL EXECUTIVE AGENCIES**

**December 2, 2011**

**(Rate Design Phase)**

FEA Ex: 2

## TABLE OF CONTENTS

## I. IDENTIFICATION

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Larry Blank. My business address is Tahoeconomics, LLC, 2533 North Carson St., Suite 3624, Carson City, NV 89706. My email address is LB@tahoeconomics.com.

Q. **WHERE ARE YOU EMPLOYED?**

A. I am currently an Associate Professor of Economics and the Associate Director with the Center for Public Utilities in the College of Business at New Mexico State University ("NMSU"). For the purposes of this proceeding, I am engaged through *TAHOEconomics*, LLC, ("Tahoe"), a Nevada-registered consulting firm I founded in 1999, and for which I serve as principal. Tahoe specializes in most policy and ratemaking facets of regulated utility industries. The expert opinions expressed herein are my own and nothing in this testimony necessarily reflects the opinions of NMSU.

Q. **ARE YOU THE SAME LARRY BLANK WITH PRE-FILED TESTIMONY IN THE REVENUE REQUIREMENTS PHASE OF THIS CASE?**

A. Yes.

## II. PURPOSE AND SUMMARY

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

A. I am testifying on behalf of the Federal Executive Agencies ("FEA") in response to two proposals in the rate design phase of the Arizona Public Service Company ("APS" or the "Company") application to adjust retail service rates. Specifically, these proposals are:

1. The APS proposal to eliminate the 90/10 incentive mechanism on the Power Supply Adjustment ("PSA") mechanism as sponsored by APS witness Peter Ewen.
2. The APS proposal to cease billing based on the unbundled rate elements as sponsored by APS witness Charles Miessner.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. First, I recommend that the Commission reject the APS proposal to eliminate the 90/10 sharing from the PSA. Instead, the Commission could retain the 90/10 incentive mechanism but modify the mechanism to limit the dollar amount of sharing with a $20 million cap as I will describe in detail below.

Second, although FEA is not opposed to billing customers based on bundled rate elements, I recommend that the Commission order APS to continue to maintain its unbundled rate billing capabilities and to follow through on its stated commitment to provide customers the option to receive billing based on unbundled charges.

## III. APS PROPOSAL TO ELIMINATE THE 90/10 INCENTIVE IN THE PSA

**Q. WHAT IS THE CURRENTLY APPROVED 90/10 INCENTIVE MECHANISM FOR THE PSA?**

A. As described on page 15 of Mr. Ewen's direct testimony, the 90/10 sharing provision allows APS to recover 90% of that portion of (most) fuel expenses that exceed the revenue collected through the Base Fuel Rate, and allows APS to retain 10% fuel cost savings when fuel expenses fall below the amount collected through the Base Fuel Rate. As stated by the Commission in Decision No. 69663 (pp. 106-107), the 90/10 sharing provision is an "incentive mechanism" to "insure that APS is diligent in its fuel procurement."

**Q. IN YOUR OPINION, DOES THE 90/10 SHARING OF INCREASES AND DECREASES IN FUEL COST CREATE A STRONG INCENTIVE FOR PRUDENT PROCUREMENT OF FUEL?**

A. Yes, I would characterize this as a strong incentive mechanism for those employees at APS responsible for fuel procurement with millions of dollars at stake (see e.g., Mr. Ewen's Chart 1).

**Q. DO YOU BELIEVE THE COMMISSION'S DECISION TO IMPLEMENT THE 90/10 INCENTIVE MECHANISM WAS A GOOD APPROACH?**

A. Because it is very difficult to regulate fuel and purchased power procurement activities under the traditional regulatory process, the 90/10 sharing serves as a novel and balanced approach to create financial incentives for the adoption of prudent procurement strategies. However, the Company cannot be expected to perfectly control realized fuel costs with its portfolio strategies and cannot guarantee that the over- and under-recoveries net each other out over the long term. Even the best procurement practices cannot control the market forces determining natural gas prices. Therefore, if the Commission is considering a modification to this mechanism, it may want to consider limiting the dollar amount of the sharing with an absolute dollar sharing cap.

**Q. IF THE COMMISSION CONSIDERS A MODIFICATION TO IMPLEMENT A SHARING CAP, WHAT WOULD YOU PROPOSE?**

A. For the purpose of shielding the Company and customers from any extraordinary changes in market fuel prices, I recommend that the Commission limit the sharing amount to not exceed $20 million per year. In other words, when fuel expense exceeds Base Fuel Rate revenue by more than $200 million, the Company would be allowed to recover $180 million (90%) plus all amounts in excess of $200 million. On the other hand, if the fuel expense fell by more than $200 million, the Company would retain $20 million from the Base Fuel Rate revenues, but the amounts in excess of $200 million would be credited to customers. The $200 million target is less than 30% of the applicable 90/10 amounts included in the Company's proposed Base Fuel Rates (see Attachment PME-3, p. 3 of 4, to Mr. Ewen's Direct), and the $20 million cap on the sharing component represents 10% of the $200 million amount. The $20 million represents the maximum potential loss or gain that the Company will realize under the 90/10 sharing mechanism.

**Q. DOES THE MAXIMUM POTENTIAL LOSS OR GAIN OF $20 MILLION CREATE A SUFFICIENT INCENTIVE TO ENCOURAGE PRUDENT PROCUREMENT EFFORTS AND STRATEGIES?**

A. I would hope so. The goal of the 90/10 sharing mechanism should be to create proper procurement incentives, not to create excessive windfalls for the Company or customers. I believe my recommended sharing cap of $20 million accomplishes this goal.

**Q. SHOULD YOUR PROPOSED MODIFICATION TO THE 90/10 SHARING ALTER THE ADJUSTED FUEL EXPENSES INCLUDED IN THE COMPANY'S PROPOSED BASE FUEL RATES?**

A. No. The adjustments for known and measurable changes continue to be relevant for the base rates regardless of whether the Company's request to eliminate the 90/10 sharing is adopted or not.

**Q. WHAT IS YOUR RECOMMENDATION ON THE 90/10 SHARING MECHANISM?**

A. I recommend that the Commission reject the APS proposal to eliminate the 90/10 sharing from the PSA. Instead, the Commission could modify the incentive mechanism to limit the dollar amount of sharing with a $20 million cap as I describe in detail above.

## IV. <u>APS PROPOSAL TO REMOVE UNBUNDLED ELEMENTS FROM BILLS</u>

**Q. DOES THE FEA OPPOSE THE COMPANY'S PROPOSAL TO USE BUNDLED RATHER THAN UNBUNDLED RATE ELEMENTS FOR BILLING PURPOSES?**

A. No; however, I recommend that the Commission order APS to continue to maintain its unbundled rate billing capabilities and to follow through on its stated commitment to provide customers the option to receive billing based on unbundled charges. The details provided with unbundled billing can be useful for customers who desire more transparency in billing. On the other hand, the FEA supports those customers who prefer simplified billing.

**Q. HAS THE COMPANY INCLUDED THE UNBUNDLED BILLING OPTION IN ITS PROPOSED TARIFF REVISIONS?**

A. The Company's proposed tariff rate schedules continue to include the Unbundled Standard Offer Service rates, but I do not see language that specifies that a customer must request this option. Nonetheless, the Company has made this commitment in their application and my recommendation is as stated above.

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

A. Yes.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

EXHIBIT
FEA-3
ADMITTED

COMMISSIONERS:
Gary Pierce, Chairman
Bob Stump
Sandra D. Kennedy
Paul Newman
Brenda Burns

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTLITY 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-11-0224 |

**PREFILED TESTIMONY**
**IN SUPPORT OF PROPOSED SETTLEMENT AGREEMENT**

**OF**

**LARRY BLANK**

**ON BEHALF OF**

**THE FEDERAL EXECUTIVE AGENCIES**

**January 18, 2012**

FEA Ex. 3

## TABLE OF CONTENTS

## I. IDENTIFICATION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Larry Blank. My business address is Tahoeconomics, LLC, 2533 North Carson St., Suite 3624, Carson City, NV 89706. My email address is LB@tahoeconomics.com.

**Q. WHERE ARE YOU EMPLOYED?**

A. I am currently an Associate Professor of Economics and the Associate Director with the Center for Public Utilities in the College of Business at New Mexico State University ("NMSU"). For the purposes of this proceeding, I am engaged through *TAHOEconomics*, LLC, ("Tahoe"), a Nevada-registered consulting firm I founded in 1999, and for which I serve as principal. Tahoe specializes in most policy and ratemaking facets of regulated utility industries. The expert opinions expressed herein are my own and nothing in this testimony necessarily reflects the opinions of NMSU.

**Q. ARE YOU THE SAME LARRY BLANK WITH PRE-FILED TESTIMONY IN THE EARLIER PHASES OF THIS CASE?**

A. Yes.

## II. PURPOSE AND SUMMARY

**Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?**

A. I am testifying on behalf of the Federal Executive Agencies ("FEA") in support of the Proposed Settlement Agreement ("the Agreement") executed by most of the parties to this proceeding and filed by Staff on January 6, 2012. As a general observation, the

Agreement is a very well-balanced attempt to address all the issues in this case, is clearly in the public interest, and should be approved by the Commission. Although I will leave it to the Company, Staff, and other parties to address all details of the Agreement, herein I specifically address the Rate Case Stay Out provision, the Lost Fixed Cost Recovery ("LFCR") mechanism, and the significant change in rate design for the large general service customer classes and their exemption from the LFCR mechanism.

**Q. PLEASE SUMMARIZE THE REMAINDER OF YOUR TESTIMONY.**

A. I will specifically explain why the resolution of the following issues is just, reasonable, and in the public interest:

1. A moratorium on base rate changes preventing any base rate increase prior to a future date is a common provision for a rate case settlement, serves to protect customers from risk related to base cost increases, and does not limit Commission flexibility to pursue important electricity policy matters through a rulemaking proceeding and/or a tariff rider as the need may arise under special circumstances.

2. To create an incentive for the successful implementation of energy efficiency ("EE") and distributed generation ("DG") programs, the Agreement requires APS to implement a targeted fixed cost recovery approach known as a Lost Fixed Cost Recovery ("LFCR") mechanism (see Sections 9.1 – 9.6 of the Agreement). This approach is far superior to the decoupling mechanism proposed by the Company in its application. In addition to the LFCR mechanism, the Agreement continues to support the EE shared net benefits performance incentives (Section 9.14(b) of the Agreement), which places Arizona ahead of the curve nationally in terms of creating incentives for APS implementation of EE programs.

3. The Agreement would significantly alter the rate design for the large general service customer classes by substantially increasing the demand charges above those proposed by APS in its application (as reflected in Attachment K to the Agreement). This constitutes a significant shift in fixed cost recovery away from the energy charges to the demand charges and, therefore, greatly reduces the risk associated with reduced energy consumption and fixed cost recovery. This substantive change in rate design greatly supports the exemptions from the LFCR mechanism in Section 9.7 of the Agreement.

## III. RATE CASE STAY OUT PROVISION

**Q. BASED ON YOUR EXPERIENCE, HAVE YOU SEEN PROVISIONS SIMILAR TO THE FOUR YEAR MORATORIUM ON RATE INCREASES IN THE PROPOSED SETTLEMENT AGREEMENT?**

A. Yes. I know of many rate case settlement agreements in which the utility agreed to not file a rate case within two or three years. This type of provision is common.

**Q. IN YOUR OPINION, IS A FOUR YEAR MORATORIUM PREVENTING BASE RATE INCREASES IN THE PUBLIC INTEREST IN THIS CASE?**

A. Yes. The Company has agreed to it and the customers will benefit from the stability in rates over the next four years. Because Company management has a fiduciary responsibility to their shareholders, they would not have agreed to this provision if it was not in the best interest of their shareholders when combined with the other provisions in the Agreement. Therefore, I see no reason why it is not in the public interest.

**Q. DOES THE RATE CASE STAY OUT PROVISION PREVENT THE ADOPTION OF IMPORTANT POLICY MEASURES DURING THIS PERIOD?**

A. No. The Commission is free to investigate necessary electric industry policy changes through rulemaking proceedings.

**Q. DOES THE RATE CASE STAY OUT PROVISION PREVENT THE IMPLEMENTATION OF TARIFF RIDERS SHOULD THE NEED ARISE?**

A. Although I am not an attorney, I do not think so. For good cause and should the need arise because APS was ordered and/or authorized to incur new costs (possibly in response to a new rulemaking), I believe the Commission has the authority beyond this Settlement Agreement to approve the implementation of a new tariff rider and, of course, the existing tariff riders will continue to function. As an additional safeguard, paragraph 21.3 explains that neither this agreement or any portion thereof shall be stated or relied upon as precedent in any future proceeding and, furthermore, the last sentence of paragraph 19.1. states: "Nothing in this provision is intended to limit the Commission's ability to change rates at any time pursuant to its lawful authority."

## IV. THE LOST FIXED COST RECOVERY MECHANISM

**Q. DO YOU CONSIDER THE LFCR MECHANISM TO BE AN IMPROVEMENT OVER THE DECOUPLING PROPOSED BY APS IN ITS APPLICATION?**

A. Yes. This approach is far superior to the decoupling mechanism proposed by the Company in its application. The Company's proposed decoupling mechanism would have resulted in an over-correction for fixed cost recovery by failing to remove the large amount of fixed costs recovered through the fixed monthly basic and demand charges.

Additionally, the proposed mechanism did not account for the significant differences in rate design across rate classes.

**Q. DOES THE LFCR SOLVE THE INCENTIVE PROBLEMS ASSOCIATED WITH ENERGY EFFICIENCY PROGRAMS?**

A. Yes. When it comes to energy efficiency programs and electric utilities, incentives or costs created for the utility may be described as a three-legged stool. First, the utility must be allowed to recover direct expenses incurred to implement and manage energy efficiency programs. Second, energy efficiency programs should cause lost revenues and unrecovered fixed costs in between general rate cases when those fixed costs are recovered through the kWh energy charges. Third, energy efficiency programs may cause foregone future capacity investments and, hence, create an opportunity cost related to the future foregone return on equity. As stated in a recent *Electricity Journal* paper, "[a] regulatory regime that ensures recovery of all three cost categories is analogous to a three-legged stool in terms of creating a stable environment for electric utilities to pursue energy efficiency in good faith."[1] With this Settlement Agreement, Arizona will now have all three legs of this "stool" in place. The LFCR addresses the second category of cost, and with the continued energy efficiency performance incentives in the form of shared net benefits (Agreement at 9.14(b)), the third category of cost is covered. Therefore, the "stable environment" in terms of energy efficiency program incentives will now be established for APS. Arizona will now be well ahead of the national curve on energy efficiency programs.

[1] Larry Blank and Doug Gegax, "Objectively Designing Shared Savings Incentive Mechanisms: An Opportunity Cost Model for Electric Utility Efficiency Programs," *The Electricity Journal*, Vol. 24, Issue 9, November 2011.

**Q. WOULD REVENUE DECOUPLING ADDRESS THE SAME INCENTIVE PROBLEM RESOLVED BY THE LFCR?**

A. In terms of energy efficiency programs, yes, but general revenue decoupling causes an unnecessary shift in risk away from the utility onto customers, because unlike the targeted approach of the LFCR, revenue decoupling causes changes in customer billing for reasons beyond lost fixed cost recovery due to EE programs. For example, revenue decoupling would impose variation in customer billing due to weather fluctuations, economic cycles, and any other factor causing change in revenue streams. Furthermore, the design of the revenue decoupling mechanism proposed by APS in its application is not the proper way to design decoupling and was flawed for all the reasons I stated in my November 18, 2011, prefiled testimony. The Settlement Agreement and the LFCR greatly corrects those problems and is far superior to what was originally proposed. The LFCR in the Agreement is a good example of the potential benefit of settlement discussions on very technical matters.

**Q. HAVE YOU WORKED ON THE DESIGN OF A MECHANISM SIMILAR TO THE LFCR MECHANISM IN ANY OTHER JURISDICTION?**

A. Yes. I analyzed and testified on the design of a LFCR mechanism implemented by Entergy in Arkansas. The LFCR proposed here for APS is very similar to the Arkansas mechanism.

## V. LARGE CUSTOMER RATE DESIGN AND THE LFCR MECHANISM

**Q. PLEASE EXPLAIN THE RATE DESIGN CHANGES FOR THE LARGER CUSTOMERS PROPOSED IN THE AGREEMENT RELATIVE TO THE RATE DESIGN IN THE APS APPLICATION?**

A. The Agreement significantly changes the rate design for the large customer classes by moving fixed cost recovery away from the kWh energy charges and substantially increasing the (ratcheted) kW demand charges. This change in rate design significantly reduces the risk of lost fixed cost recovery due to possible energy (kWh) reductions. As an example, the increases in the demand charges for the E-34 Extra Large General Service class, relative to those proposed by APS in its application, are very substantial as shown in the following table.

| Demand (kW) Charges for the E-34 Extra Large GS Class | | | | |
|---|---|---|---|---|
| Voltage | APS Application Rates per kW | Settlement Rates per kW | Settlement Increase | Percent Increase |
| Secondary | $16.646 | $19.930 | $3.284 | 19.7% |
| Primary | $15.687 | $18.649 | $2.962 | 18.9% |
| Transmission | $10.914 | $12.278 | $1.364 | 12.5% |
| Military Ded. Feeder | $11.749 | $13.392 | $1.643 | 14.0% |

These substantial increases in the demand charges greatly shield APS from risk associated with possible energy (kWh) reductions due to energy efficiency.

**Q. WHY IS IT PROPER TO NOT APPLY THE LFCR TO THE LARGE GENERAL SERVICE CUSTOMERS?**

A. Section 9.7 of the Agreement creates an LFCR exemption for large general service rate classes. This exemption is proper for the reasons stated in my November 18 prefiled testimony and the exemption is even more important given the substantive change in rate design and higher demand charges in the Agreement as discussed above. Grouping these large customers with other customer classes under the LFCR would cause unjustified shifts in fixed cost recovery away from those other customer classes onto the large customers as more fully explained in my November 18 prefiled testimony.

Q. **DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes, thank you.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**

**GARY PIERCE, Chairman**
**BOB STUMP**
**SANDRA D. KENNEDY**
**PAUL NEWMAN**
**BRENDA BURNS**

EXHIBIT
GSP-1
ADMITTED

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN | DOCKET NO. E-01345A-11-0224 |

**PREPARED DIRECT TESTIMONY**
**OF**
**MARY LYNCH**
**IN SUPPORT OF THE SETTLEMENT AGREEMENT**
**AND RATE SCHEDULE AG-1**

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

**Q.1 Please state your name and business address.**

A.1 My name is Mary Lynch. I am based in El Dorado Hills, California where I work from a home office. My corporate address is 100 Constellation Way, Suite 500, Baltimore, Maryland 21202.

**Q.2 By whom are you employed and in what capacity?**

A.2 I am employed by Constellation NewEnergy, Inc. ("CNE") as Vice President, Regulatory and Legislative Affairs, West Region. In this capacity, I am responsible for CNE's regulatory and legislative affairs in the WECC region, with a particular focus on market development issues, including retail choice, resource adequacy, capacity markets, utility procurement practices, and emerging environmental requirements.

**Q.3 Please describe your educational background and experience.**

A.3 I graduated from California State University at Northridge with a Bachelor of Arts degree in Biology in 1981 and from Northeastern University (Boston, Massachusetts) with a Masters in Business Administration in 1985. Prior to assuming my current responsibilities in the West in 2005, I had lead regulatory responsibilities for CNE's business in the PJM region, and participated extensively in working groups and committees at PJM that focused on electric market design and operation. I have also participated extensively in state regulatory proceedings dealing with the development and design of wholesale competitive energy

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

procurement practices in Maryland, New Jersey, the District of Columbia, Pennsylvania, Illinois, Delaware, Ohio, and New York.

Prior to joining CNE, from 1998 through May of 2002, I served as a vice president with Orion Power Holdings with responsibility for managing the procurement of fossil fuel supplies as well as managing regulatory affairs, with a primary focus on the New York state electric markets. From 1983 through 1998, I held various positions with New England Power Company and U.S. Generating Company managing natural gas supplies procurement operations.

**Q.4 Upon whose behalf are you testifying in this proceeding?**

A.4 I am testifying on behalf of Noble Americas Energy Solutions LLC, Constellation NewEnergy, Inc., Direct Energy, LLC and Shell Energy North America (US), L.P. ("GSP Parties"). I am providing testimony in support of proposed Rate Schedule AG-1, which is Attachment "J" to the Settlement Agreement.

**Q.5 Are the GSP Parties signatory parties to the January 6, 2012 Settlement Agreement?**

A.5 Yes.

**Q.6 Please summarize the nature of the testimony that you are presenting.**

A.6 My testimony addresses various topics relative to the proposed Experimental Rate

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

Rider Schedule AG-1 ("Rate Schedule AG-1") from the perspective of prospective Generation Service Providers ("GSP"), as that term is defined in Rate Schedule AG-1. If Rate Schedule AG-1 is approved by the Commission, as currently proposed, each of the companies on whose behalf I am testifying has a commercial interest in participating as a GSP. My testimony does not discuss the nature or details of proposed Rate Schedule AG-1, as the APS' witness has provided that detailed review, making it unncessary and unproductive for me to simply duplicate the same.

**Q.7 Please provide an overview of your testimony.**

A.7 In the testimony that follows, I will describe (i) how the GSP Parties intend to proceed in offering service to prospective customers under the Rate Schedule AG-1 program and (ii) the potential benefits to prospective customers and the general public under the Rate Schedule AG-1 program. In addition, given the fact that Section 17.1 of the Settlement Agreement expressly states that the Rate Schedule AG-1 program "does not address the subject of retail electric competition," I will explain later in this testimony how the Rate Schedule AG-1 program differs from retail electric competition as it exists in other jurisdictions.

**Q.8 Please describe how the GSP Parties, as prospective GSPs, would proceed in offering service to prospective customers under the Rate Schedule AG-1**

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

**program.**

A.8 The are two parallel sets of activities that will occur in connection with offering service to prospective customers under Rate Schedule AG-1. First, the GSP Parties, as prospective GSPs, will work with other interested parties to finalize the operational details of Rate Schedule AG-1. Specifically, there are references in Rate Schedule AG-1 to "program guidelines" that will address the details of the customer enrollment process, APS's provision of Imbalance Energy, billing by the GSP to APS for energy deliveries, and energy scheduling protocols. The GSP Parties anticipate that preparation of the program guidelines will be accomplished through a collaborative effort of APS, prospective GSPs, and customer representatives, with input and oversight from Commission Staff.

Second, competitive commercial activities will occur. With respect to these activities, Rate Schedule AG-1 allows GSPs to provide wholesale power to APS on behalf of specific customers, who will pay APS for this alternative supply in lieu of other generation related charges to which they are otherwise subject under APS's approved tariffs. The approval of Rate Schedule AG-1 will initiate a highly competitive process during which prospective GSPs will work with interested, eligible customers to structure wholesale supply agreements that meet the customers' pricing and risk management requirements, and that meet contracting and pricing requirements established by Rate Schedule AG-1. The manner in which each prospective GSP approaches this competitive activity is, of course,

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

proprietary to each company and will likely differ to some extent for each prospective GSP. Generally speaking, however, prospective GSPs will work with customers to (i) assist with identifying their metered accounts that can be aggregated for service under Rate Schedule AG-1, (ii) analyze the historic energy usage of those accounts, and (iii) review with them the different types of supply structures and value propositions that the prospective GSP can offer. The goal of these commercial activities will be to reach commercial terms acceptable to both parties for a contract that the GSP will execute with APS for wholesale delivery of energy to APS on the AG-1 eligible customer's behalf.

**Q.9 Do the GSP Parties anticipate that there will be active interest in the Rate Schedule AG-1 program by qualifying customers?**

A.9 It is not possible at this time to predict with certainty the level of interest that eligible customers will have in taking service under Rate Schedule AG-1. Each customer's decision will be predicated upon market conditions that exist at the time they become eligible for service, and whether the prospective GSP is able to offer a value proposition to the eligible customer. Nevertheless, based on customer interest in other Western states that have somewhat similar programs, the GSP Parties anticipate that there will be substantial interest on the part of eligible customers for service under Rate Schedule AG-1.

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

**Q.10 Upon what information or experience is that anticipation based?**

A.10 There are several reasons why the GSP Parties have an expectation of substantial customer interest in service under Rate Schedule AG-1:

- First, APS has indicated in responses to data requests submitted by the GSP Parties during the discovery phase of the rate case proceeding that (i) "the Company generally anticipates that Schedule AG-1 would be available to retail customers that are currently receiving power from the APS grid," (ii) "APS anticipates the aggregation provision would allow a significant number of customers to be eligible" and (iii) as of October 31, 2011, APS had estimated potential participation under Rate Schedule AG-1 to include "14 customer entities comprising 496 metered accounts and roughly 1,650,000 MWh per year."
- Second, evidence from other states where the ability for customers to choose alternative, competitively procured electricity has been introduced suggests that there will be signficant customer interest and enrollment. For instance, here in the West, California, ground zero for the energy crisis, lifted its suspension of retail choice in 2010 and offered commercial and industrial customers four separate phases in which customers not currently procuring their electricity in a competitive manner could submit notices to procure their electricity

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

needs separate from the utility standard offer. Each phase had a customer participation cap with requests to participate accepted on a first come, first served basis. Each of the first three phases garnered so much customer interest that they were fully subscribed within minutes, and in some cases, within a few seconds. The fourth phase was conducted on January 13, 2012 and the results of that phase are not yet known.

- Third, Rate Schedule AG-1 service is limited to very large commercial and industrial customers, many of whom have nationwide operations and already have experience shopping for competitively priced electricity in other states. Those same customers, who have accounts in the APS service territory that would be eligible for service under Rate Schedule AG-1, are expected to have a proclivity toward evaluating electricity supply alternatives to determine whether or not their Arizona operations will benefit from enrollment in service under Rate Schedule AG-1. Moreover, these same customers are experienced in stimulating competition among prospective suppliers in order to get "the best deal" possible.
- Fourth, the Settlement Agreement itself has been signed by several entities that represent likely eligible customers or who are themselves likely to be eligible customers, including Arizona Competitive Power

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

Alliance ("AzCPA"), Arizonans for Electric Choice and Competition ("AECC"), Freeport-McMoran Copper and Gold, Inc. ("Freeport-McMoran"), The Kroger Co. ("Kroger"), Wal-Mart Stores, Inc and Sam's West, Inc. ("Wal-Mart"). It is our understanding that several of those parties, including AzCPA, AECC, Freeport McMoRan, Kroger and Wal-Mart, are submitting statements and/or testimony in support of the Settlement Agreement and of Rate Schedule AG-1.

**Q.11 Please discuss from the perspective of the GSP Parties, as prospective GSPs, what you believe are the potential benefits to (i) prospective customers and (ii) the general public under the Rate Schedule AG-1 program.**

A.11 A significant potential benefit to customers who will be eligible for service under Rate Schedule AG-1 includes the ability to better manage their energy-related expenses by fixing the pricing of the generation portion of their energy needs by means of the contract executed between APS and the GSP on their behalf. That is, customers who take service under Rate Schedule AG-1 will not be subject to the variablity that could otherwise occur with APS' tariffs, such as the E-32-L, E-32 TOU-L, E-34, and E-35 rate schedules and various approved APS adjusters applicable to those rate schedules. In addition, competition among GSPs to provide service to eligible Rate Schedule AG-1 customers will create downward pressure on prices and spur the development of innovative energy products and

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

services. Finally, any savings that customers achieve while taking service under Rate Schedule AG-1 can be used to support other aspects of their business, increasing their competitiveness and contribution to the Arizona economy.

**Q.12 Is there a risk that APS' residential customers could be asked in APS' next rate case to compensate APS for any unrecovered fixed generation costs that APS might experience as a consequence of the Rate Schedule AG-1 program?**

A.12 No. Section 17.2 of the Settlement Agreement is expressly worded to preclude that possibility.

**Q.13 Given that the Settlement Agreement expressly states that Rate Schedule AG-1 "does not address the subject of retail electric competition," please describe the differences between the Rate Schedule AG-1 program and retail electric competition.**

A.13 There are at least two significant differences between retail electric competition as contemplated under Arizona law and the electric service that is provided for under Rate Schedule AG-1. First and foremost, the GSP will transfer title to the electricity the GSP bought, at the direction of an eligible Rate Schedule AG-1 customer, to APS at a delivery point outside of APS' network delivery. Upon taking title to the electricity, APS remains the transmission and distribution provider for the Rate Schedule AG-1 customer. In essence, service under Rate

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

Schedule AG-1 is not unlike the type of contractual hedging that APS performs to manage its system-wide portfolio of energy costs, except that the contract executed between the GSP and APS pursuant to Rate Schedule AG-1 will be "earmarked" on behalf of a specific customer, who will be billed for energy at the price the Rate Schedule AG-1 customer in question negotiated with the GSP, thereby bypassing the unbundled generation component of their otherwise applicable APS rate schedule.

A second significant difference between service under Rate Schedule AG-1 and retail electric competition is that in Arizona, the retail supplier is required to have first obtained a Certificate of Convenience and Necessity ("CC&N") for that purpose from the Commission, because the retail supplier under retail electric competition is considered to be the load serving entity of the end use customer. A GSP providing energy to APS pursuant to Rate Schedule AG-1 is not required to secure a CC&N because the electricity that the GSP is providing is delivered to APS at a wholesale delivery point; and, as noted above, title to the electricity passes to APS at that time. In that regard, the GSP is NOT utilizing nor paying for access to APS' transmission and distribution network, and APS remains the load serving entity for the retail customer providing all services, including the generation delivery and billing under a Commission approved rate schedule. In this instance, that rate schedule would be Rate Schedule AG-1.

This structure described above, while significantly different from the

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

typical retail model as implemented across the United States, does contain many program similarities that are in place in a few other states in the West, most notably in Washington and Montana.

**Q.14 Please summarize the program similarities between the proposed AG-1 rate schedule and the customer choice programs implemented in Washington and Montana.**

A.14 Both Washington and Montana are similar to Arizona in that the utilities in those states do not belong to an organized regional transmission organization. Proposed Rate Schedule AG-1 is similar to Puget Sound Energy's Electric Schedule 449 in Washington State and Northwestern Energy's rate schedule CESGTC-1 in Montana.

Schedule 449 was implemented in 2003 for the largest industrial customers of Puget Sound Energy. These customers are free to negotiate wholesale power deliveries to Puget Sound Energy. Wholesale energy providers, acting on behalf of the customer(s) are not required by the Washington Utilities and Transportation Commission to register, obtain a license or certificate or obtain Commission approval to participate in the program. Puget Sound Energy remains both the balancing authority and the load serving entity.

In the state on Montana, Northwestern Energy offers their largest industrial customers the opportunity to bypass Northwestern Energy's energy procurement

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

portfolio and arrange wholesale energy deliveries with wholesale energy providers under rate schedule CESGTC-1. Similar to Puget Sound Energy's program, Northwestern Energy remains both the balancing authority and the load serving entity. The Montana Public Service Commission does not register, license nor certificate the wholesale energy providers that arrange for electricity deliveries on a wholesale basis.

**Q.15 Do you have any further comments with respect to Rate Schedule AG-1, as now proposed?**

A.15 Yes. The GSP Parties believe that APS's introduction of Rate Schedule AG-1 was a constructive feature of APS's Application. The subsequent modifications and additions to the original rate schedule, which occurred as a result of the settlement negotiations involving parties having an interest in the successful deployment of this type of service, have served to ensure that Rate Schedule AG-1, as now proposed, is in the public interest and should be approved by the Commission.

**Q.16 Does that complete your Direct Testimony in support of Rate Schedule AG-1, as attached to the Settlement Agreement as Attachment "J"?**

A.16 Yes, it does.

c:\users\angela\documents\larry\aps\2010 rate case 11-0224\noble-constellation-direct-shell\direct test of m. lynch.doc

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

# BEFORE THE ARIZONA CORPORATION COMMISSION

**COMMISSIONERS**

**GARY PIERCE, Chairman**
**BOB STUMP**
**SANDRA D. KENNEDY**
**PAUL NEWMAN**
**BRENDA BURNS**

**EXHIBIT**
GSP-2
ADMITTED

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN | ) | DOCKET NO. E-01345A-11-0224 |

**Summary of testimony submitted on January 18, 2012 by**
**Mary Lynch on behalf of**
**Noble Americas Energy Solutions LLC, Constellation NewEnergy, Inc.,**
**Direct Energy, LLC and Shell Energy North America (US), L.P.**

**Docket No. E-01345A-11-0224**

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

On January 6, 2012, a Proposed Settlement Agreement ("Agreement") was submitted to the Arizona Corporation Commission ("Commission") by the Commission Staff ("Staff") on behalf of Arizona Public Service Company ("APS") and other signatories to the Agreement. Noble Americas Energy Solutions LLC, ("Noble Solutions"), Constellation NewEnergy, Inc. ("Constellation"), Direct Energy LLC ("Direct Energy"), and Shell Energy North America (US), L.P. ("Shell Energy") are signatories to the Agreement. Attachment J to the Agreement describes a proposed Experimental Rate Rider Schedule AG-1 ("Rate Schedule AG-1"). If approved, Rate Schedule AG-1 will allow large commercial and industrial customers in the APS service territory to select a Generation Service Provider ("GSP") who will provide Generation Service to APS on the customer's behalf.

On January 18, 2012, Mary Lynch submitted testimony on behalf of Noble Solutions, Constellation, Direct Energy, and Shell Energy (together referred to as the "GSP Parties") in support of the Agreement and Rate Schedule AG-1. Ms. Lynch is the Vice President, Regulatory and Legislative Affairs, West Region for Constellation. Ms. Lynch has worked in the energy industry since 1985 and currently is responsible for CNE's regulatory and legislative affairs in the WECC region, with a particular focus on market development issues, including retail choice, resource adequacy, capacity markets, utility procurement practices, and emerging environmental requirements.

Ms. Lynch's testimony explains that implementation of Rate Schedule AG-1 will include interested parties working collaboratively with APS and Staff to finalize the program guidelines that will address the details of customer enrollment, APS's provision of imbalance energy, as well as energy scheduling and billing protocols. Ms. Lynch also explains that entities such as the GSP Parties would work with customers who are eligible for service under Rate Schedule AG-1 to establish commercial terms acceptable to both

LAWRENCE V.
ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

parties, which would enable the customer to select a GSP for delivery of Generation Service to APS on the eligible customer's behalf. In that regard, Ms. Lynch observes that the process of establishing commercial terms under which an eligible customer would select a GSP will be highly competitive.

Ms. Lynch's testimony discusses why the GSPs believe that there will be significant interest on the part of eligible customers to take service under Rate Schedule AG-1. The reasons include (i) information provided by APS on the number of customers that will be eligible, (ii) the strong interest that occurred in California when customers were allowed to choose alternative suppliers in 2010 for the first time in nearly ten years, (iii) the fact that at least some of the customers who are eligible for service under Rate Schedule AG-1 have nationwide operations that are already competitively shopping for electricity in other jurisdictions, and (iv) the fact that several parties to this proceeding either are or represent eligible customers and have expressed support for the Agreement and Rate Schedule AG-1.

In her testimony, Ms. Lynch also discusses the benefits of Rate Schedule AG-1 to eligible customers and to the general Arizona public. Specifically, eligible customers will be able to more actively manage their energy related costs under Rate Schedule AG-1 and avoid the price volatility that can accompany utility tariffs. In addition, competition among GSPs to provide service to eligible customers will create downward pressure on prices and spur the development of innovative energy products and services. In that regard, any savings that customers achieve while on Rate Schedule AG-1 could be used to support other aspects of their businesses, which in turn could create benefits for the Arizona economy. Ms. Lynch further explains that these benefits are achieved without requiring residential customers to compensate APS for any unrecovered fixed generation costs that APS might experience as a consequence of the Rate Schedule AG-1, since the

LAWRENCE V. ROBERTSON, JR.
ATTORNEY AT LAW
P.O. BOX 1448
TUBAC, ARIZONA 85646
(520)398-0411

Agreement specifically precludes that possibility.

Finally, Ms. Lynch's testimony explains that the service contemplated under Rate Schedule AG-1 differs from retail electric competition in two significant ways. First, deliveries of energy by the GSP are to APS, not to the customer. Upon taking title to the energy delivered to it by the GSP, APS continues to provide transmission and delivery service to the customer, and to directly bill the customer for the electricity consumed by the customer, even though the customer will be billed for energy based on the price negotiated between the GPS and Rate Schedule AG-1 customer. Second, because APS remains the supplier of energy to the customer, the GSP is not required to obtain a Certificate of Convenience and Necessity ("CC&N"). In connection with the foregoing, Ms. Lynch notes that Rate Schedule AG-1 is similar to customer choice programs in both Washington and Montana.

LUBIN & ENOCH, P.C.
Nicholas J. Enoch
State Bar No. 016473
Jarrett J. Haskovec
State Bar No. 023926
349 North Fourth Avenue
Phoenix, Arizona 85003
Telephone: (602) 234-0008
Facsimile: (602) 626-3586
E-mail: nick@lubinandenoch.com

Attorneys for Intervenors
IBEW Locals 387, 640 & 769

EXHIBIT
IBEW-1
ADMITTED

**BEFORE THE ARIZONA**

**CORPORATION COMMISSION**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | Docket No. E-01345A-11-0224<br><br>**NOTICE OF FILING DIRECT TESTIMONY OF G. DAVID VANDEVER** |

Pursuant to the Chief Administrative Law Judge's Procedural Order (p. 3) dated July 29, 2011, Intervenors Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"), Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640"), and Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769"), by and through undersigned counsel, hereby provide notice of its filing of the attached Direct Testimony of G. David Vandever in this docket.

RESPECTFULLY SUBMITTED this 18th day of November, 2011.

LUBIN & ENOCH, P.C.

Jarrett J. Haskovec

Jarrett J. Haskovec, Esq.
Attorney for Intervenors
IBEW Locals 387, 640 & 769

Original and thirteen (13) copies
of Intervenors' Notice filed
this 18th day of November, 2011, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing
transmitted electronically or
via regular mail this same date to:

Lyn Farmer, Chief ALJ
Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

Meghan H. Grabel, Esq.
Thomas L. Mumaw, Esq.
Pinnacle West Capital Corporation Law Department
P.O. Box 53999
MS 8695
Phoenix, Arizona 85072-3999
Attorneys for Applicant

Leland Snook
Zachary Fryer
Kelly Hauert
Pinnacle West Capital Corporation
P.O. Box 53999
MS 9708
Phoenix, Arizona 85072-3999
Representatives for Applicant

Janice Alward, Esq.
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007-2927

Steven M. Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007-2927

Daniel W. Pozefsky, Esq.
Residential Utility Consumer Office
1100 West Washington, Ste. 220
Phoenix, Arizona 85007
Attorney for Intervenor

Jeffrey W. Crockett, Esq.
Brownstein Hyatt Farber Schreck LLP
One East Washington Street, Suite 2400
Phoenix, AZ 85004
Attorney for Intervenor AAR

Greg Patterson, Esq.
Munger Chadwick
2398 East Camelback Road, Ste. 240
Phoenix, Arizona 85016
Attorney for Intervenor Alliance

Michael M. Grant, Esq.
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, Arizona 85016-9225
Attorney for Intervenor for AIC

Gary M. Yaquinto
Arizona Investment Council
2100 North Central Avenue, Ste. 210
Phoenix, Arizona 85004
Representative for Intervenor

Karen S. White, Esq.
Air Force Utility Law Field Support Center
AFLOA/JACL-ULFSC
139 Barnes Drive
Tyndall AFB, Florida 32403
Attorney for Intervenor FEA

C. Webb Crockett, Esq.
Patrick J. Black, Esq.
Fennemore Craig, P.C.
3003 North Central Avenue, Ste. 2600
Phoenix, Arizona 85012-2913
Attorneys for Intervenors Freeport, *et al.*

Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 East 7th Street, Ste. 1510
Cincinnati, Ohio 45202
Co-counsel for Intervenor Kroger

John W. Moore, Jr., Esq.
7321 North 16th Street
Phoenix, Arizona 85020
Co-counsel for Intervenor Kroger

Michael A. Curtis, Esq.
William P. Sullivan, Esq.
Melissa A. Parham, Esq.
Curtis, Goodwin, Sullivan, Udall & Schwab, P.L.C.
501 East Thomas Road
Phoenix, Arizona 85012-3205
Attorneys for Intervenor Town of Gilbert

Michael W. Patten, Esq.
Roshka, DeWulf & Patten, PLC
400 East Van Buren Street, Ste. 800
Phoenix, Arizona 85004
Co-counsel for Intervenor TEP

Bradley S. Carroll, Esq.
Tucson Electric Power Company
One South Church Avenue, Ste. UE 201
Tucson, Arizona 85701
Co-counsel for Intervenor TEP

Timothy M. Hogan, Esq.
Arizona Center for Law in the Public Interest
202 East McDowell Road, Ste. 153
Phoenix, Arizona 85004
Attorney for Intervenors WRA, SWEEP, and ASBA/AASBO

David Berry
Western Resource Advocates
P.O. Box 1064
Scottsdale, Arizona 85252-1064
Representative for Intervenor

Barbara Wyllie-Pecora
14410 West Gunsight Drive
Sun City West, Arizona 85375
Intervenor

Cynthia Zwick
1940 East Luke Avenue
Phoenix, Arizona 85016
Intervenor

Lawrence V. Robertson, Jr., Esq.
Attorney at Law
P.O. Box 1448
Tubac, Arizona 85646
Attorney for Intervenors SWPG/Bowie and Noble/Constellation/Direct/Shell

Laura E. Sanchez, Esq.
NRDC
P.O. Box 287
Albuquerque, New Mexico 87103
Attorney for Intervenor NRDC

Mel Beard
4108 W. Calle Lejos
Glendale, Arizona 85310
Intervenor

Jay I. Moyes, Esq.
Steve Wene, Esq.
Moyes Sellers & Hendricks
1850 N. Central Ave., Suite 1100
Phoenix, Arizona 85004
Attorneys for Intervenor AzAg

Jeffrey J. Woner
K.R. Saline & Assoc., PLC
160 N. Pasadena, Suite 101
Mesa, Arizona 85201
Consultant for Intervenor AzAg

Scott S. Wakefield, Esq.
Ridenour, Hienton & Lewis, P.L.L.C.
201 N. Central Avenue, Suite 3300
Phoenix, Arizona 85004
Attorney for Intervenor Wal-Mart

Steve W. Chriss
Senior Manager, Energy Regulatory Analysis
Wal-Mart Stores, Inc.
2011 S.E. 10th St.
Bentonville, Arkansas 72716
Representative for Intervenor Wal-Mart

Craig A. Marks, Esq.
Craig A. Marks, PLC
10645 N. Tatum Blvd., Ste. 200-676
Phoenix, Arizona 85028
Attorney for Intervenor AARP

Carrie Jones

**Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A1. G. David Vandever. My business address is 3060 W. Deer Valley Rd., Phoenix, Arizona 85027.

**Q2. PLEASE DESCRIBE YOUR RECENT EMPLOYMENT.**

A2. I am the Business Manager/Financial Secretary for Intervenor Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"). The position of Business Manager/Financial Secretary is an elected union position. I was elected to this position on July 15, 2010. Because all IBEW local unions also have a person holding the position of "President," it is common for persons outside of our organization to believe that the "President" is the principal officer of the Local. That is not the case. Article 17, §§ 4 and 8 of the Constitution of the International Brotherhood of Electrical Workers, AFL-CIO, clearly states that the Business Manager/Financial Secretary is the "principal officer" of any IBEW local union.

Prior to my becoming Business Manager/Financial Secretary for IBEW Local 387, I was employed by APS for over 29 years, the last 24 as an Electric Troubleman in Western division of Metro Operations. I served my apprenticeship for the Journeyman Lineman classification at APS from 1982 through 1985.

**Q3. WHO IS IBEW LOCAL 387?**

A3. IBEW Local 387 is a labor organization which, for the most part, represents non-managerial utility workers throughout most of the State of Arizona. For example, IBEW Local 387 is the duly elected and recognized exclusive bargaining agent for a substantial number of employees of Arizona Water Company, Asplundh Tree Expert Company, Graham County Electric Cooperative, Inc., Navopache Electric

Cooperative, Inc., and the Santa Cruz District of UniSource Energy Corporation. IBEW Local 387 is also the duly elected and recognized exclusive bargaining agent for approximately one-thousand nine-hundred (1,900) employees of APS. IBEW Local 387 and APS have entered into a long series of collective bargaining agreements ("CBA") dating back to 1945 concerning rates of pay, wages, hours of employment, and other terms and conditions of employment. Our current 3-year CBA with APS was ratified on September 16, 2011.

**Q4. DO YOU BELIEVE APS IS A RESPONSIBLE CORPORATE CITIZEN?**

A4. Absolutely. While by no means perfect, the relationship between IBEW Locals 387 and APS is one which is mature, stable and in accordance with the mission of IBEW Local 387. It is clear that this stability has enured to the benefit of APS, its employees, and customers. In my opinion, the importance of the relationship between a public service corporation and its employees cannot be overstated. I firmly believe that my opinion in this regard is shared by the executives at APS.

**Q5. WHO IS IBEW LOCAL 640?**

A5. Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640") is a sister local of IBEW Local 387. IBEW Local 640 is currently supplying electricians to the Abengoa CSP solar project near Gila Bend, and stands ready to supply qualified Arizona electricians at all skill levels to support the large, utility-scale solar projects that have been mandated by the ACC. In addition, IBEW Local 640 supplies employees to various power generation plants, including the Palo Verde Nuclear Generating Station ("Palo Verde"), periodically for maintenance outages through an International Maintenance Agreement between the Arizona Building Trades and contractors such as Bechtel, GD Barri & Associates, and Day & Zimmerman. IBEW Local 640 has also provided employees to APS in the past as a part of a task force assembled to assist in underground construction in residential housing developments and currently stands ready to provide qualified labor for the ongoing residential solar programs. IBEW Local 640 has a direct interest in ensuring that APS has a continued demand for its supply of qualified, efficient manpower to perform their electrical installations.

**Q6. WHO IS IBEW LOCAL 769?**

A6. Like IBEW Local 640, Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769") is another of our sister locals. IBEW Local 769 is a labor organization which represents non-managerial utility workers throughout the State of Arizona. For example, IBEW Local 769 is the duly elected and recognized exclusive bargaining agent for the employees of the Mohave County Electric Operations of UniSource, Mohave Co-Op, Frontier Communications and Griffith Power Plant. In addition, IBEW Local 769 is the exclusive bargaining agent for all IBEW outside line workers in the State of Arizona and its scope of work also includes tele-data, street light and trenching. For example, IBEW Local 769 has provided outside line construction work for APS through Wilson Construction, Klondyke, NPL, Henkels & McCoy and Sturgeon Electric, among others. Currently, IBEW Local 769 is providing bargaining unit employees to Klondyke and NPL for the installation of sub-transmission lines for APS. At any given time, IBEW Local 769 will have anywhere from five (5) to two-hundred (200) of its bargaining unit employees working for subcontractors of APS.

**Q7. ARE IBEW LOCALS 387, 640, AND 769 SEPARATE LEGAL ENTITIES?**

A7. Yes. In addition, it is well-settled that our International Union and its constituent local unions, including my own, are also separate legal entities. That being said, the various IBEW Local Unions in the State of Arizona meet on a regular basis to discuss issues of mutual concern and, general speaking, we are familiar with and supportive of the actions of each other.

**Q8. DO IBEW LOCALS 387, 640, AND 769 HAVE A STAKE IN THIS PROCEEDING OTHER THAN IN THEIR CAPACITY AS LABOR ORGANIZATIONS?**

A8. Yes. As building owners in APS's service territory, each of the Locals fall within the definition of a "small-business" customer under the E-32 Rate Plan - *i.e.*, the standard plan for APS commercial customers who have a demand of less than 3,000 kilowatts a month.

**Q9. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A9. I am testifying in support of APS's Application for a rate hike.

**Q10. WHY IS THE PROPOSED RATE HIKE IN THE PUBLIC INTEREST?**

A10. Any public service corporation is entitled to a fair rate of return on the fair value of its property, no more and no less. IBEW Locals 387, 640, and 769 firmly believe that APS's request rate hike meets this test.

As you know, Article XV, §3 of the Arizona Constitution expressly states that the interests of public service employees are on par with those of patrons. It reads as follows:

> The corporation commission shall have full power to, and shall... make reasonable rules, regulations, and orders, by which such [public service] corporations shall be governed in the transaction of business within the State, and... make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the

health, of the ***employees*** and patrons of such corporations[.]

It goes without saying that it costs a substantial amount of money for a public service corporation to hire, train, and maintain a highly skilled work force. Similarly, it costs a great deal of money for any public service corporation to preserve the safety and health of its employees and patrons. In these tremendously difficult economic times, I am certain that many in the public may not understand, or want to understand, the need to raise their electric rates, in part, for this reason but I can assure you, APS is competing for a talented workforce, particularly when it comes to linemen, substation electricians and those working in generation. Unlike most of the national and local economy, this is one portion of the job market where demand outstrips supply. Unless APS has the ability to provide a highly competitive employment package, you can be assured that APS and, in turn, the public will suffer. I hope that this Commission and the other parties bear this is mind. I submit that it is in the "the interests of residential utility consumers"[1] to have a highly skilled workforce providing safe and reliable service even if that means that they are paying, what they believe to be at least, something more than rock-bottom prices for electric service. IBEW Locals 387, 640, and 769 believe that the rate relief proposed in this case will help ensure that APS will be able to meet its commitments to its employees and customers in the years to come.

**Q11. IN YOUR ESTIMATION, HAS APS MADE SIGNIFICANT EFFORTS TO CONTROL LABOR-RELATED OPERATING EXPENSES DURING THE ECONOMIC DOWNTURN?**

---

[1] *See* A.R.S. §40-462(A).

A11. Without question. I would first note that IBEW Local 387 formerly represented approximately 2,300 bargaining unit employees when we filed direct testimony in the prior APS general rate case back in December 2008. Now, less than three years later, the number of employees Local 387 represents at APS has dropped to approximately 1,900. The numbers have dropped largely due to reductions in force and attrition, including retirements. APS has offered many employees – according to APS, precisely 1,251 employees since the beginning of the test year – early retirement incentive packages where positions were slated to be eliminated or consolidated. Accordingly, overall employment levels have been much reduced at APS from levels prevailing prior to the economic downturn. APS has also had to comply with aggressive operational expense reduction requirements in the past two rate cases, the last of which required a $30 million annual expense reduction for five years. Given that APS's payroll represent a sizeable part of APS's expenses, APS has necessarily had to look at cuts in labor expenses to meet the required reduction levels. As a part of its compliance efforts for 2010, APS reported to the ACC on April 29, 2010, that it had cut $5,500,000 in payroll expenses resulting from reduced staffing levels and lowered overtime costs at APS fossil plants.

**Q12. IN THEIR APPLICATION TO INTERVENE, IBEW LOCALS 387, 640, AND 769 DISCUSSED EXTENSIVELY THE "AGING WORKFORCE" PROBLEM FACING APS AND MOST OTHER UTILITIES AND SUGGESTED SOME SOLUTIONS. COULD YOU PLEASE ELABORATE ON THIS ISSUE AND WHAT YOU PROPOSE IN THIS REGARD?**

A12. Certainly. As you noted, IBEW Locals 387, 640, and 769 discussed the "aging workforce" issue extensively in our application to intervene in this matter, and accordingly, I would, as a preliminary matter, refer you to the application, which I hereby incorporate by reference, for a general discussion of the scope and scale of the industry-wide problem and what some other state public utility commissions have done to address it. Beyond that, I would like to share a few other observations concerning this issue and to suggest a way forward in a constructive effort to solve this problem.

By the "aging workforce" problem, I mean the difficulties, burdens, and/or concerns associated with having a substantial share of employees in particular positions eligible to retire within the coming years and the attendant issues relating to the loss of seasoned employees with extensive experience, expertise, and institutional knowledge as well as the need to recruit, train, and replace such employees in order to ensure the continuous provision of safe and reliable service to utility customers. More precisely, when employees who have worked at APS for a decade or more retire – a set of circumstances APS currently faces and will increasingly face in the years to come – they take with them their experience, skill, and knowledge about the electrical system, company culture (including its positive safety culture), operating procedures, and applicable safety rules and standards, among other things. However, replacing such employees by hiring upon their retirement simply will not work. As I will discuss further in a moment, it literally takes years of apprenticeship and training to become adequately qualified to work in skilled positions, and generally substantially longer to hone one's skills and develop additional expertise. Moreover, unless there is a period of overlap between the periods of service of soon-to-be-retiring employees and newly hired workers, any transfer of knowledge and know-how is not possible. Accordingly, with anticipated retirement levels rising in the approaching years, APS faces both a challenge and an opportunity to ensure that it continues to attract and employ fully qualified personnel consonant with its efforts to provide safe and reliable service to customers.

The IBEW Utility Department Director, James Hunter, addressed this issue in an interview last year. He explained that utilities are losing, and will continue to lose, a large percentage of their workforce, including linemen and other skilled workers, each year to retirement. However, without an adequate pipeline of new workers and an opportunity to train them to become fully qualified and develop necessary expertise and knowledge before more experienced employees retire, utilities are at serious risk of having inadequate levels of fully qualified staff to carry out their mandates of providing safe and reliable service to customers. He noted that this problem has been exacerbated by the pressure placed on utilities during the economic downturn by state public utility commissions to keep operating expenses, and, in turn, rates, as low as possible, prompting many utilities to institute hiring freezes and to offer early retirement incentive packages to veteran workers. As a result, most utilities are having a difficult time keeping pace with historical attrition levels, much less ramping up hiring in anticipation of the impending wave of retirements. The webcast for the interview is available at http://www.ibew.org/articles/10daily/1009/100914_HunterInterview.htm.

APS has recognized in its direct testimony that this is a significant challenge it will face in the near future, noting that 38% percent of Energy Delivery's regular employees will be eligible to retire within the next five (5) years and fully 50% percent of Fossil Generation's employees will be eligible to retire by 2014.[2] These numbers will keep growing as time goes on. APS's Response to IBEW Locals' First Set of Data Requests, attached hereto as Exhibit A, tells the same story. APS has likewise specifically identified this issue in the Company's Form 10-K filing for the fiscal year ended December 31, 2010, as an "employee workforce factor[] that could adversely affect [its] business and financial condition." This is

[2] *See, e.g.*, Testimony of Daniel T. Froetscher, pp. 19-20; Testimony of Mark A. Schiavoni, p. 26.

consistent with my own understanding of the magnitude of the impending wave of retirements at APS based on discussions with employees and my own experience at the Company.

The situation regarding APS's journeyman linemen and journeyman electricians is illustrative of this concern. Journeyman linemen at APS generally perform electrical line construction and maintenance work, among other things. Journeyman electricians typically perform a variety of electrical, mechanical, and structural construction and maintenance activities related to electric substations, underground cables, and ground-mounted equipment. Both positions require highly-skilled employees to perform this dangerous work and to ensure the delivery of safe and reliable electric service to customers. Such work is also physically demanding and generally involves a great deal of work outside and occasionally in inclement weather.

Based on numbers provided by APS, 24 out of 184 regular journeyman linemen, or 13%, are presently eligible for retirement. Assuming current staffing levels, the number of journeyman lineman eligible for retirement will rise to 57, or 31%, by December 31, 2016. Similarly, 5 out of the 15, or one-third (33%) of all, journeyman linemen designated to do "hot stick" work (involving the use of insulated poles to work on high-voltage, energized power lines) are already retirement eligible at present. For journeyman electricians, 13 out of 112, or 12%, are currently retirement eligible. By the end of 2016, the number of retirement-eligible journeyman electricians will likely rise to 39, or 35%.

The figures for control and auxiliary operators, who operate and control power plant (and related) equipment, and E&I technicians, who perform instrumentation and electrical maintenance work, are in many ways even more concerning. Based on APS's figures, for auxiliary operators designated PS3T2 AO/MECH MNTC, which is by far the largest contingent of auxiliary operators at APS, 32 out of 110, or 29%, are currently eligible to retire, a figure that will increase to 61, or over 55% (assuming present staffing levels), by December 31, 2016. As for the three E&I technician designations at APS (namely, E&I TECH ELECT/ADV INSTR, E&I TECH INSTR REPR/ADV ELECT, AND E&I Technician), 72%, 41%, and 13% of these designations, respectively, are currently retirement eligible. By the end of 2016, these percentages are projected to reach as high as 90%, 88%, and 46%, respectively.

It takes a great deal of time and training to become fully qualified in each of these positions. For the journeyman lineman and journeyman electrician positions, the term of apprenticeship consists of a minimum of 8,000 hours, or approximately 4 years, of training with not less than 576 hours of related instruction. For E&I technicians, the term of apprenticeship is 4.3 years. For control operators and auxiliary operators, the term of apprenticeship is 4 years and up to 3 years, respectively.

Because of the extensive training required to perform these highly-skilled and inherently dangerous jobs, APS must expend a substantial amount of money for each employee it hires in each of these classifications to become fully qualified and at least minimally capable of replacing a more seasoned employee who retires. APS has indicated that it incurs the following average costs (including wages during apprenticeship and training costs) to replace one existing, fully-qualified employee in each classification:

- for journeyman linemen and journeyman electricians, $250,000 per employee;
- for E&I technicians, $213,000 per employee;
- for control operators, $211,000 per employee; and

• for auxiliary operators, $154,000 per employee.

In light of these costs, it is imperative that APS be afforded rate relief sufficient to allow it to ramp up its hiring in these and other classifications in the short-term so that APS may have an appropriate number of fully-qualified personnel in place when the impending wave of retirements begins to hit in order to secure its ability to provide safe and reliable service on an ongoing basis. To this end, IBEW Locals 387, 640, and 769 propose that APS receive substantial dedicated funds – over and above what APS presently seeks in the form of rate relief – to enable it to increase its hiring significantly to meet these challenges effectively. We propose that the mechanism by which these efforts would be funded would be in the form of a charge to customers, and further that APS track and report annually the actual level of new hiring and the overall staffing levels in these positions.

Given the above costs and retirement eligibility figures provided by the Company, for APS to hire and train new workers to replace the literally hundreds of veteran bargaining unit employees who are set to retire prior to the end of 2016, it would cost the Company approximately $59,429,000. This figure would simply cover replacing retiring employees in the above highly-skilled classifications; it does not include costs of hiring new employees in many other positions, nor does it include costs associated with recruiting and hiring personnel in the above classifications, among other costs.

We recognize and are sensible of the fact that the Commission is not in a position, particularly in these tough economic times, to grant the rate relief necessary to enable APS to set about hiring in order to replace all such employees and to preserve the already much diminished 2011 levels of staffing. If we assume that the impending wave of retirements merely represents a doubling of the historical rate of retirement in these classifications – a very conservative assumption, it would seem, in light of the historical retirement data provided by APS – and accordingly discount these figures to exclude the retirements that would have likely occurred anyway, this cost would drop to $29,714,500. Although admittedly not all of the retirements in these classifications would hit before the probable filing date of the next APS rate case under the prior settlement agreement, it must be recognized that the prescribed period of training for most of these positions is four years or more. The Commission, therefore, must allow at least that much lead time to APS. Given that APS is seeking an effective new rate date of July 1, 2012, without action in this rate case, APS would almost certainly not be positioned to do the hiring necessary to ensure that sufficient numbers of fully-qualified personnel would be in place by the end of 2016.

For all these reasons, it is critically important that APS be afforded rate relief sufficient to enable it to undertake the recruiting and hiring efforts necessary to ensure the provision of safe and reliable electric service in years to come.

**Q13. DOES THIS CONCLUDE YOUR TESTIMONY?**

A13. Yes.

F:\Law Offices\client directory\IBEW L 387\APS\100\pleadings\2011 11 18 Vandever Direct Testimony.wpd

# EXHIBIT A

aps

**JEFFREY W. JOHNSON**
Regulatory Affairs Supervisor
State Regulation

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-250-2661
Jeffrey.Johnson@aps.com

November 7, 2011

Nicholas J. Enoch
Lubin & Enoch, P.C.
349 North Fourth Avenue
Phoenix, AZ 85003

RE: Arizona Public Service Company's 2010 Test Year Rate Case
Docket No. E-01345A-11-0224

Attached, please find Arizona Public Service Company's Response to IBEW's First Set of Data Requests in the above-referenced matter.

If you have any questions regarding this information, please contact Zachary Fryer at (602)250-4167.

Sincerely,

Jeffrey W. Johnson

JJ/cd
Attachment

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.1: Describe the Electrician-Journeyman position by stating:

A. The job description and qualifications;

B. The business unit or portfolio *(e.g.,* Energy Delivery, Fossil Generation) with which such position is associated for purposes of company organization;

C. The number of Electrician-Journeyman positions at APS; and

D. The nature of the work performed including, *inter alia,* what role they serve in promoting the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of APS.

Response:

A. Generally, a Journeyman Electrician performs electrical, mechanical, and structural construction and/or maintenance activities related to electric substations, as well as the installation and maintenance of underground cables and ground mounted equipment such as switches and transformers. Generally, to qualify as a Journeyman Electrician, an individual must complete the APS Electrician Apprenticeship or other accredited Electrician program and demonstrate the required skills and knowledge of a Journeyman Electrician.

B. Energy Delivery and Shared Services.

C. 112.

D. See response to IBEW 1.1 A above.

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.2: Describe the Lineman-Journeyman position by stating:

A. The job description and qualifications;

B. The business unit or portfolio *(e.g.,* Energy Delivery, Fossil Generation) with which such position is associated for purposes of company organization;

C. The number of Lineman-Journeyman positions at APS; and

D. The nature of the work performed including, *inter alia,* what role they serve in promoting the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of APS.

Response:

A. Generally, a Journeyman Lineman performs both overhead and underground electrical line construction and/or maintenance activities. These include the installation of utility poles, installing and repairing overhead wires and underground cables, and the installation of pole mounted and grounded mounted equipment such as switches or transformers. Work on overhead power lines can be performed by either climbing a utility pole or through the utilization of an aerial man-lift (bucket). Generally, to qualify as a Journeyman Lineman, an individual must complete the APS Electrician Apprenticeship or other accredited Lineman program and demonstrate the required skills and knowledge of a Journeyman Lineman.

B. Energy Delivery.

C. 184.

D. See response to IBEW 1.2(A) above.

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.3: Describe the Technician-E&I position by stating:

A. The job description and qualifications;

B. The business unit or portfolio *(e.g.,* Energy Delivery, Fossil Generation) with which such position is associated for purposes of company organization;

C. The number of Technician-E&I positions at APS; and

D. The nature of the work performed including, *inter alia,* what role they serve in promoting the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of APS.

Response:

A. Please see the attached job description and qualifications for E&I Journeyman, APS14984.

B. Fossil Generation

C. 100.

D. Please see the attached job description and qualifications for E&I Journeyman, APS14984.

Witness: Daniel T. Froetscher

# Job Title: E & I Journeyman

**Function:** Supports the safe, efficient and cost effective production of electrical energy by performing Instrumentation and Electrical Maintenance work. Writes/reviews work scope and hazard/risk assessment of the work assignment. Performs other duties as assigned.

**Requirements:**
Reasonable and necessary overtime will be required. Shift work may be required.

**Qualifications:** Must qualify as an Electrical and Instrumentation Journeyman or equivalent.

***Minimum* Requirements:**
Applicant must:
1. Successfully complete E&I Apprenticeship or demonstrate equivalent skills and knowledge.

**Job Description:**
1. Read work orders, Technical manuals, schematics, wiring diagrams, Control Wiring Diagrams (CWDs) and other diagrams related to the work assignment. Enters and manipulates data in a maintenance computer system to record maintenance activity. Maintains instrumentation lists, parameters and settings.. Uses troubleshooting software such as Pi, DB Doc, CITECT and vendor internet sites for graphs and trends.. Operates recorders, desktop and laptop computers.

2. Inspects and tests electrical and instrumentation equipment and circuits and analyzes test data to identify malfunctions or defects using wiring diagrams and testing devices.

3. Removes, disassembles, calibrates and maintains electrical and instrumentation equipment, controls, fixtures and appliances including digital and analog controls, tune and maintain on line and off line configurations on Distributive Control Systems (DCS), solid state circuits, process flows and controls, programmable logic controllers, interlocks, recorders and frequency generators, pneumatic and hydraulic actuators, positioners, pressure switches, flame scanners, control valves, dampers, thermocouples and RTDs, motors, batteries, battery chargers, Uninterruptable Power Supply (UPS), gantry and overhead cranes, exciter brushes, grounding brushes, contactors and metering using hand tools and power tools, cuts, bends and threads pipe, tubing and conduit to specifications using tools such as pipe, conduit and tube cutters, benders and threaders.

4. Install, test, clean, remove, repair and troubleshoot medium and low voltage circuit breakers and related protective relay equipment and transformers. Sets up, verifies settings and interprets data from protective relays, Install, inspects and repairs proper grounds on high voltage lines and transformers up to and including the generator. Maintain grounding grids, perform cadmium welds, install grounding trucks/breakers following all grounding and bonding procedures using live line tools such as shotguns, hot sticks, rubber gloves, rubber mats and blankets, live/dead/live and arc flash procedures.

5. Knowledge of APM and safety standards related to electrical and instrumentation maintenance such as grounding and bonding procedures, arc-flash protection, Possible Asbestos Containing Material procedures (PACM), Material Safety Data Sheets (MSDS), confined space entry, Company LOTO procedure, personal protective equipment including face, hand and body shields, the use and care of voltage rated rubber gloves, scaffold inspection, ladder safety, hazardous material handling and all material contained in the Accident Prevention Manual.

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.4: Describe the Operator-Power Plant position by stating:

A. The job description and qualifications;

B. The business unit or portfolio (*e.g.,* Energy Delivery, Fossil Generation) with which such position is associated for purposes of company organization;

C. The number of Operator-Power Plant positions at APS; and

D. The nature of the work performed including, *inter alia,* what role they serve in promoting the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of APS.

Response: APS does not have a job title "Operator-Power Plant", but does have the positions of Control Operator and Auxiliary Operator. APS provides the following information for those positions:

A. Please see the job description and qualifications for Control Operator and Auxiliary Operator attached as APS14985 and APS14986.

B. Fossil Generation

C. 75 Control Operators and 111 Auxiliary Operators.

D. Please see the job description and qualifications for Control Operator and Auxiliary Operator attached as APS14985 and APS14986.

Witness: Daniel T. Froetscher

# Job Title: Control Operator

**Function:** Supports the safe, efficient and cost effect production of electric energy by operating and controlling power plant equipment. Monitors instrumentation to determine plant conditions. Performs actions necessary to keep the plant operating within prescribed limits. Writes/reviews work scope and hazard/risk assessment of the work assignment.
Performs other duties as assigned.

**Requirements:**
Reasonable and necessary overtime will be required. Shift work may be required.

**Qualifications:** Completion of Control Operator Trainee Curriculum or equivalent.

**Minimum Requirements:**
Applicant must be qualified as an Auxiliary Operator

**Job Description:**

1. Reads work orders, technical manuals, blueprints and diagrams related to the work assignment. Writes/reviews work scope and hazard/risk assessment of the work assignment.
2. Knowledge of APM and safety standards related to work such as personal protective equipment, hazardous material handling, asbestos containing material (ACM) awareness, MSDS, confined space entry, company LOTO procedures, ladder safety, rigging and hand signals, and all material contained in the accident prevention manual. This may include preparation of LOTOs.
3. Monitor, adjust and regulate equipment operations and conditions such as water, fuel and air flow based on data from recording and indicating instruments or from computers controls to generate specified electrical power or to regulate the flow of power to the power grid. Adjust generation voltage and current output based on system conditions.
4. Monitor and inspect the Distributive Control System indicators (DCS), alarms, charts, meters, gauges, log books, safety devices and power plant equipment and communicate with other plant personnel to detect evidence of abnormal conditions with boilers, turbines, generators and auxiliary equipment.
5. Assess trends and analyze abnormal conditions to troubleshoot and take corrective action such as adjusting controls or initiating maintenance requests to ensure continuous and reliable operation of equipment and systems.
6. Start or stop generators, emergency generators, auxiliary pumping equipment, turbines, and other power plant equipment following proper procedures and sequences and coordination with co-workers.
7. Direct personnel to open and close valves, breakers and switches in sequence in the control of auxiliary equipment such as pumps, fans, compressors, condensers, feed water heaters, filters, pulverizers , and chemical injection equipment, to supply water, fuel, lubrication, air, and auxiliary power and control waste water, and ash disposal.
8. Monitors emissions to comply with all regulatory requirements.
9. Direct others with the connection/disconnection of equipment from electrical circuits, water, steam and air systems to isolate equipment for removal, maintenance or return to service following the Company LOTO procedure.
10. Communicate with systems operators to regulate and coordinate transmission loads, frequencies and line voltages.
11. Communicate with Supervisor Operations Crew Leader, peers, or subordinates by radio, telephone, in written form, e-mail, or in person to provide and receive information utilizing three way communication and the phonetic alphabet.
12. Record and compile operational data, completing and maintaining forms, logs, and reports to document start-ups, shut-downs, load curtailment, test reports, generation, etc.
13. Must have basic computer skills.
14. General understanding of Production and Processing of raw materials such as coal, water, lime; production processes and other techniques for maximizing the effective generation of electricity.

**Intermediate Instrumentation**

**Description:**

1. The intent of the Intermediate Instrumentation skill set is to aid in the troubleshooting-determining causes of electrical, hydraulic, pneumatic, or mechanical failure of instrumentation devices.
2. General understanding of the function, operation, and internal parts of electrical, hydraulic and pneumatic control systems including relays, timers, regulators, circuit breakers, fuses, switches, distribution equipment, control valves, dampers, actuators, controllers, conductors, thermocouples, RTD's, and supervisory equipment.
3. General understanding of power plant systems/processes and the function of the equipment within the system including ignition, combustion, boiler, turbine, control valves, supervisory, generator, water chemistry, distribution controls, solid state, hydraulic systems, emissions, purge, recorders, excitation, computer devices, circuit breakers and test equipment.
4. General understanding of basic electrical theory.
5. General understanding of instrumentation and techniques used in measuring level, volume, temperature, flow, motion and process control and instrumentation used in testing circuits and components including voltage testers, ammeters, ohmmeters, and multimeters.
6. General understanding of control and wiring diagrams (CWD's), piping & instrumentation diagrams (P&ID's), logic diagrams and drawing and diagram symbols.
7. General understanding of the mechanical parts of instrumentation equipment and parts such as drivers, and valves, fasteners and anchors, gaskets and packing, seals, filters, bushings, sleeves, rings and liners.
8. General understanding of industrial math: add, subtract, multiply, divide, fractions, decimals, basic algebra and geometry to solve for area, volume, circumference, right angles and solve process math problems with mass, weight, pressure, temperature, and flow and conversion of units.
9. General understanding of plant science and process dynamics.

**Training Objectives:** Training required to maintain proficiency in the craft.

# Job Title: Auxiliary Operator

**Function:** Supports the safe, efficient and cost effective production of electric energy by operating and monitoring turbines, generators, scrubbers, bag houses, and plant auxiliary equipment. Performs chemical analysis of boiler water, wells, and circulating water and operating water treatment and chemical addition systems and minor mechanical maintenance. Writes/reviews work scope and hazard/risk assessment of the work assignment. Performs other duties as assigned. NOTE: 4C Board Operator and 4C Scrubber AO have been replaced by the Auxiliary Operator position.

**Requirements:**

1. Reasonable and necessary overtime will be required. Shift work may be required.
2. Must qualify for fire brigade duties (specific plants only).

**Qualifications:** Must qualify as an Auxiliary Operator.

**Minimum Requirements:**

Applicant must have completed Auxiliary Operator Trainee curriculum or equivalent.

**Job Description:**

1. Reads work orders, technical manuals, blueprints and diagrams related to the work assignment. Writes/reviews work scope and hazard/risk assessment of the work assignment.
2. Knowledge of APM and safety standards related to auxiliary operator work such as personal protective equipment, hazardous material handling, asbestos containing material (ACM) awareness, MSDS, confined space entry, company LOTO procedures, ladder safety, arc flash protection, and all material contained in the accident prevention manual.
3. Take field readings from charts, meters, and gauges at established intervals to ensure proper and efficient operation of the plant.
4. Diagnose and correct equipment, system problems and other abnormal operating conditions by monitoring and inspecting power plant equipment.
5. Communicate with Control Operator on any abnormal conditions. Coordinate any field action with the Control Operator.
6. Reports any need for equipment repair.
7. Under the direction of the Control Operator, manipulate field controls on all power plant auxiliary equipment. This includes the following systems such as boilers, turbines, water, fuel, air, ash handling, pollution control systems, auxiliary power etc. The operation of pumps, fans, compressors, condensers, feed water heaters, filters, chemical injection equipment, scrubbers, ZLDs, bag houses etc.
8. Open and close valves, dampers, switches, and breakers in the appropriate sequence following operating procedures to shut down and start up equipment.
9. Isolate equipment from all energy sources to remove, inspect or maintain it by identifying the proper equipment and corresponding valves, breakers, switches. Hang LOTO tags at boundary points following the company LOTO procedure to ensure the safety of personnel and equipment.
10. Inspect records and log book entries, and communicate with other plant personnel, in order to assess equipment operating status.
11. Clean and ensure the proper lubrication of equipment such as generators, turbines, pumps, fans, conveyors, and compressors in order to prevent equipment failure or deterioration. Checks oil levels, lubricates, joints, adjust belts and tensioners, replace filters, tighten gland and pipe joints for preventative maintenance.
12. Record and compile operational data, completing and maintaining forms, logs, and reports.
13. Collect water and oil samples for laboratory analysis.
14. Perform laboratory analysis on water samples. At Cholla the Water Analyst Position will be required to qualify as an AO on one of the AO areas.
15. Reset tripped electric relays in coordination with the Control Operator following arc flash protection procedures.
16. Clear obstructions in filters and equipment by removing debris and back flushing such as with heat exchangers.

17. Analyze field problems such as hot bearings, plugged filters, low oil, clogged heat exchangers, bottom ash build up, loss of coal flow, lime flow drop off, etc. and take appropriate action to ensure continuous and reliable operation of equipment and systems.
18. Respond to emergencies such as fires, hazardous material spills and excess water spills.
19. Communicate with Supervisor, Operations Crew Leader and peers by radio, telephone, in written form, e-mail, or in person to provide and receive information-particularly at shift turnover.
20. Identify and report to the Control Operator all items that have an adverse impact on unit and/or equipment efficiency and reliability.

**Basic Mechanical Maintenance**
**Description:**

1. Performs an assessment of the malfunction of the mechanical equipment by listening, looking, hearing, smelling and feeling the condition of the equipment and by consulting with operations personnel.
2. Verifies the proper isolation of the mechanical equipment from energy sources before performing work using the company clearance procedure.
3. Performs basic maintenance equipment repair and replacement on mechanical equipment including pumps, valves, motors, compressors, blowers, fans, gear boxes, heat exchangers, hydraulic systems, conveyers, and piping.
4. Disassembles mechanical equipment with hand tools, power and pneumatic tools including wrenches, hammers, files, saws, drills, grinders, pullers, measuring devices and cutting torches.
5. Moves machinery and equipment using hoists, jacks, dollies, rollers, trucks and mobile equipment.
6. Diagnoses mechanical problems and determines corrective action checking blueprints and repair manuals.
7. Inspects internal parts of the mechanical equipment for defects, excessive wear and broken parts by visual examination.
8. Reassembles internal parts including bushings, bearings, sleeves, rings, liners, mechanical seals, packing gears and wheels, lubricants and housing; installs the mechanical equipment back in the system.
9. Supports overhaul and repair work on boilers, generators, steam and combustion turbines as a member of a work team involving the safe coordination of multiple projects in close proximity, communicating with others to disassemble, move, and replace large pieces of equipment and meet outage schedules.
10. Assembles, installs, and repairs threaded metal and PVC piping systems.
11. Cleans, adds/replaces fluids, change filters and lubricates shafts, bearings, gears and other moving machinery parts, inspects and adjusts belts, packing, rollers, and pulleys, for preventative maintenance.

**Training Objectives:** Training required to maintain proficiency in the craft.

**Advancement:** After demonstrating proficiency as an Auxiliary Operator, individuals may voluntarily train for Control Operator.

# IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
## DOCKET NO. E-01345A-11-0224
## OCTOBER 26, 2011

IBEW 1.5: Please identify the present mean and median ages of APS's work force with respect to the following job classifications:

A. Electrician-Journeyman

B. Lineman-Journeyman,

C. Technician-E&I, and

D. Operator-Power Plant.

Response: A, B, C and D.

| Job | | Head Count | Age_Mean | Age_Median |
|---|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 1 | 52.1 | 52.1 |
| Auxiliary Operators | Ops Tech Trainee T-1 | 1 | 28.2 | 28.2 |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 8 | 53.4 | 52.2 |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 110 | 49.0 | 52.1 |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 3 | 51.3 | 46.2 |
| Control Operator | Control Operator | 3 | 43.1 | 36.9 |
| Control Operator | Oper Control | 1 | 53.6 | 53.6 |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 24 | 49.2 | 52.3 |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 50 | 49.5 | 51.1 |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 1 | 58.0 | 58.0 |
| Electrician-Journeyman | Electrician | 112 | 46.5 | 45.1 |
| Lineman-Journeyman | Lineman Hotstick | 15 | 44.8 | 39.0 |
| Lineman-Journeyman | Lineman Journeyman | 184 | 44.5 | 43.5 |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 29 | 58.0 | 59.0 |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 17 | 55.0 | 55.1 |
| Technician-E&I | E&I Technician | 54 | 48.1 | 50.1 |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.6: Please state, for each the past five (5) calendar years, the share of retirement-eligible employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request, who opted to retire.

Response: Below are the percentages and number of individuals in each of the job classifications that retired from 2010 to present:

**Retirements: 2006-2010**

| Job | | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0 | 0 | 0 | 1 | 1 |
| Auxiliary Operators | *Ops Tech Trainee T-1* | 0 | 0 | 0 | 0 | 0 |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 0 | 0 | 0 | 0 | 0 |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 0 | 0 | 0 | 0 | 5 |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 6 | 9 | 8 | 3 | 22 |
| Control Operator | Control Operator | 1 | 1 | 2 | 0 | 1 |
| Control Operator | Oper Control | 0 | 0 | 0 | 1 | 0 |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 0 | 0 | 0 | 3 | 1 |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 0 | 0 | 0 | 0 | 3 |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 0 | 0 | 0 | 0 | 0 |
| Electrician-Journeyman | Electrician | 1 | 8 | 7 | 1 | 6 |
| Lineman-Journeyman | Lineman Hotstick | 0 | 0 | 0 | 0 | 0 |
| Lineman-Journeyman | Lineman Journeyman | 4 | 6 | 10 | 7 | 9 |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 0 | 0 | 0 | 0 | 3 |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 0 | 0 | 0 | 0 | 8 |
| Technician-E&I | E&I Technician | 12 | 10 | 8 | 15 | 23 |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

**Retirements: 2006-2010**

| Job | | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0% | 0% | 0% | 0% | 0% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0% | 0% | 0% | 0% | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 0% | 0% | 0% | 0% | 0% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 0% | 0% | 0% | 0% | 2% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 3% | 4% | 4% | 1% | 11% |
| Control Operator | Control Operator | 0% | 0% | 1% | 0% | 0% |
| Control Operator | Oper Control | 0% | 0% | 0% | 0% | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 0% | 0% | 0% | 1% | 0% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 0% | 0% | 0% | 0% | 1% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 0% | 0% | 0% | 0% | 0% |
| Electrician-Journeyman | Electrician | 0% | 4% | 3% | 0% | 3% |
| Lineman-Journeyman | Lineman Hotstick | 0% | 0% | 0% | 0% | 0% |
| Lineman-Journeyman | Lineman Journeyman | 2% | 3% | 5% | 3% | 4% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 0% | 0% | 0% | 0% | 1% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 0% | 0% | 0% | 0% | 4% |
| Technician-E&I | E&I Technician | 6% | 5% | 4% | 7% | 11% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.7: Please state the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who are presently retirement eligible.

Response:

**Retirement Eligibility Summary**

| Job | | Current (9/30/11) | Current (9/30/11) |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0 | 0% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 3 | 38% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 32 | 29% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 1 | 33% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 0 | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 7 | 29% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 14 | 28% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 1 | 100% |
| Electrician-Journeyman | Electrician | 13 | 12% |
| Lineman-Journeyman | Lineman Hotstick | 5 | 33% |
| Lineman-Journeyman | Lineman Journeyman | 24 | 13% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 21 | 72% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 7 | 41% |
| Technician-E&I | E&I Technician | 7 | 13% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.8: Please state: (1) the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who will be retirement eligible between the present and December 31,2012; and (2) anticipated hiring and attrition levels for each of the job classifications referenced in the preceding data request between the present and December 31, 2012.

Response: APS provides the following information on retirement eligibility between September 30, 2011 and December 31, 2012 and does not have information to respond to anticipated hiring and attrition levels.

**Retirement Eligibility Summary**

| Job | | 9/30/11 - 12/31/12 | 9/30/11 - 12/31/12 |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0 | 0% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 0 | 0% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 7 | 6% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 0 | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 2 | 8% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 2 | 4% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 0 | 0% |
| Electrician-Journeyman | Electrician | 2 | 2% |
| Lineman-Journeyman | Lineman Hotstick | 0 | 0% |
| Lineman-Journeyman | Lineman Journeyman | 7 | 4% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 3 | 10% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 1 | 6% |
| Technician-E&I | E&I Technician | 2 | 4% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.9: Please state: (1) the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who will be retirement eligible between January 1,2013, and December 31, 2014; and (2) anticipated hiring and attrition levels for each of the job classifications referenced in the preceding data request between January 1,2013, and December 31, 2014.

Response: APS provides the following information on retirement eligibility between January 1, 2013 and December 31, 2014 and does not have information to respond to anticipated hiring and attrition levels.

**Retirement Eligibility Summary**

| | Job | 1/1/13 - 12/31/14 | 1/1/13 - 12/31/14 |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 1 | 100% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 1 | 13% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 11 | 10% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 0 | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 3 | 13% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 6 | 12% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 0 | 0% |
| Electrician-Journeyman | Electrician | 13 | 12% |
| Lineman-Journeyman | Lineman Hotstick | 0 | 0% |
| Lineman-Journeyman | Lineman Journeyman | 13 | 7% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 2 | 7% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 5 | 29% |
| Technician-E&I | E&I Technician | 7 | 13% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.10: Please state: (1) the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who will be retirement eligible between January 1,2015, and December 31,2016; and (2) anticipated hiring and attrition levels for each of the job classifications referenced in the preceding data request between January 1,2015, and December 31,2016.

Response: APS provides the following information on retirement eligibility between January 1, 2015 and December 31, 2016 and does not have information to respond to anticipated hiring and attrition levels.

**Retirement Eligibility Summary**

| Job | | 1/1/14 - 12/31/16 | 1/1/14 - 12/31/16 |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0 | 0% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 2 | 25% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 11 | 10% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 0 | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 3 | 13% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 7 | 14% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 0 | 0% |
| Electrician-Journeyman | Electrician | 11 | 10% |
| Lineman-Journeyman | Lineman Hotstick | 0 | 0% |
| Lineman-Journeyman | Lineman Journeyman | 13 | 7% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 0 | 0% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 2 | 12% |
| Technician-E&I | E&I Technician | 9 | 17% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.11: With respect to each of the job classifications discussed in the preceding data request, please state or estimate the average length of time needed for an inexperienced, newly hired employee in each classification to become fully qualified in such classification by way of training, experience, or otherwise.

Response: For Lineman-Journeyman and Lineman-Electrician, the term of apprenticeship for each of the positions corresponds to that customarily set by the trade, or a minimum of 8,000 hours based on a 40-hour week and/or successful completion of all Performance Based Competencies as determined by the Joint Apprenticeship Committee comprised of membership from both APS and the IBEW Local 387. The hours to be spent in related instruction shall not be less than 576 hours.

- For E&I Technician, the term of apprenticeship is 4.3 years.
- For Control Operator, the term of apprenticeship is 4 years.
- For Auxiliary Operator, the term of apprenticeship is up to 3 years.

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.12: Please state or estimate the cost to APS, on a per employee basis, of training an inexperienced, newly hired employee in each classification to replace fully qualified personnel in such classification with respect to each of the job classifications discussed in the preceding data request.

Response:

- For Lineman-Journeyman and Lineman-Electrician, the estimated average cost is approximately $250,000 per employee, including wages, and training costs (materials and instructor costs).
- For E&I Technician, the estimated average cost is approximately $213,000 per employee, including wages, and training costs (materials and instructor costs).
- For Control Operator, the estimated average cost is approximately $211,000 per employee, including wages, and training costs (materials and instructor costs).
- For Auxiliary Operator, the estimated average cost is approximately $154,000 per employee, including wages, and training costs (materials and instructor costs).

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.13: Please describe in detail the nature, design, and efficacy of APS'.s current efforts to recruit and train employees in each of the classifications referenced in the preceding data request with a view to meeting challenges associated with APS's "aging workforce."[1]

Response: APS recently established a Workforce Planning function to strategically address future retirement and attrition forecasts to use that information for the hiring and talent pipeline planning process to meet the challenges associated with, among other things, employee retirement.

APS has been successful in utilizing internal talent. The Company develops apprentices through its Apprenticeship program. The Company currently has 27 Lineman Apprentices and 9 Electrician Apprentices.

APS also has a partnership with Chandler-Gilbert Community College and Powerlineman.com to assist in filling our talent pipeline. Gilbert College provides coursework for future apprentices to become eligible in our apprenticeship program. We have also recruited Journeyman through Powerlineman.com which assists us in getting national and regional talent.

[1] *See, e.g.,* Testimony of Daniel T. Froetscher, pp. 19-20; Testimony of Mark A Schiavoni, p. 26.

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.14: Has APS offered any incentives for employees to take early retirement from the beginning of the Test Year through the present date?

Response: Yes.

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.15: If the answer to the preceding data request is in the affirmative, please state:

A. The number of employees who received an offer;

B. The criteria established to qualify for an offer;

C. A generalized description of the offers; and

D. The reason(s) for the offer.

Response:

A. 1,251.

B. APS identified certain positions that were to be eliminated or consolidated, and employees in those positions were eligible for the offer.

C. Employees represented by IBEW are offered severance pursuant to the Pinnacle West Capital Corporation Severance Program which includes 8 weeks of base pay plus one week of base pay for each year of service. Severance pay is capped at 52 weeks. The Severance Program also provides for continuation of medical benefits through the severance period and outplacement assistance.

D. See response to question 1.15(B).

Witness: Daniel T. Froetscher

LUBIN & ENOCH, P.C.
Nicholas J. Enoch
State Bar No. 016473
Jarrett J. Haskovec
State Bar No. 023926
349 North Fourth Avenue
Phoenix, Arizona 85003
Telephone: (602) 234-0008
Facsimile: (602) 626-3586
E-mail: nick@lubinandenoch.com

Attorneys for Intervenors IBEW Locals 387, 640 & 769

EXHIBIT
IBEW-2
ADMITTED

**BEFORE THE ARIZONA**

**CORPORATION COMMISSION**

| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN. | Docket No. E-01345A-11-0224<br><br>**NOTICE OF FILING TESTIMONY OF G. DAVID VANDEVER IN SUPPORT OF SETTLEMENT AGREEMENT** |
|---|---|

Pursuant to the Chief Administrative Law Judge's Procedural Order (p. 2) dated December 23, 2011, Intervenors Local Union 387, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 387"), Local Union 640, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 640"), and Local Union 769, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 769"), by and through undersigned counsel, hereby provide notice of their filing of the attached Testimony of G. David Vandever in Support of Settlement Agreement in this docket.

RESPECTFULLY SUBMITTED this 17th day of January, 2012.

LUBIN & ENOCH, P.C.

Jarrett J. Haskovec

Jarrett J. Haskovec, Esq.
Attorney for Intervenors
IBEW Locals 387, 640 & 769

Original and thirteen (13) copies of Intervenors' Notice filed this 17th day of January, 2012, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing transmitted electronically or via regular mail this same date to:

Lyn Farmer, Chief ALJ
Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

Meghan H. Grabel, Esq.
Thomas L. Mumaw, Esq.
Pinnacle West Capital Corporation Law Department
P.O. Box 53999
MS 8695
Phoenix, Arizona 85072-3999
Attorneys for Applicant

Leland Snook
Zachary Fryer
Kelly Hauert
Pinnacle West Capital Corporation
P.O. Box 53999
MS 9708
Phoenix, Arizona 85072-3999
Representatives for Applicant

Janice Alward, Esq.
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007-2927

Steven M. Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007-2927

Daniel W. Pozefsky, Esq.
Residential Utility Consumer Office
1100 West Washington, Ste. 220
Phoenix, Arizona 85007
Attorney for Intervenor

Jeffrey W. Crockett, Esq.
Brownstein Hyatt Farber Schreck LLP
40 North Central Avenue, 14th Floor
Phoenix, Arizona 85004
Attorney for Intervenor AAR

Greg Patterson, Esq.
Munger Chadwick
2398 East Camelback Road, Ste. 240
Phoenix, Arizona 85016
Attorney for Intervenor Alliance

Michael M. Grant, Esq.
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, Arizona 85016-9225
Attorney for Intervenor for AIC

Gary M. Yaquinto
Arizona Investment Council
2100 North Central Avenue, Ste. 210
Phoenix, Arizona 85004
Representative for Intervenor

Karen S. White, Esq.
Air Force Utility Law Field Support Center
AFLOA/JACL-ULFSC
139 Barnes Drive
Tyndall AFB, Florida 32403
Attorney for Intervenor FEA

C. Webb Crockett, Esq.
Patrick J. Black, Esq.
Fennemore Craig, P.C.
3003 North Central Avenue, Ste. 2600
Phoenix, Arizona 85012-2913
Attorneys for Intervenors Freeport, *et al.*

Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 East 7th Street, Ste. 1510
Cincinnati, Ohio 45202
Co-counsel for Intervenor Kroger

John W. Moore, Jr., Esq.
7321 North 16th Street
Phoenix, Arizona 85020
Co-counsel for Intervenor Kroger

Michael A. Curtis, Esq.
William P. Sullivan, Esq.
Melissa A. Parham, Esq.
Curtis, Goodwin, Sullivan, Udall & Schwab, P.L.C.
501 East Thomas Road
Phoenix, Arizona 85012-3205
Attorneys for Intervenor Town of Gilbert

Michael W. Patten, Esq.
Roshka, DeWulf & Patten, PLC
400 East Van Buren Street, Ste. 800
Phoenix, Arizona 85004
Co-counsel for Intervenor TEP

Bradley S. Carroll, Esq.
Tucson Electric Power Company
One South Church Avenue, Ste. UE 201
Tucson, Arizona 85701
Co-counsel for Intervenor TEP

Timothy M. Hogan, Esq.
Arizona Center for Law in the Public Interest
202 East McDowell Road, Ste. 153
Phoenix, Arizona 85004
Attorney for Intervenors WRA, SWEEP, and ASBA/AASBO

David Berry
Western Resource Advocates
P.O. Box 1064
Scottsdale, Arizona 85252-1064
Representative for Intervenor

Barbara Wyllie-Pecora
14410 West Gunsight Drive
Sun City, Arizona 85375
Intervenor

Cynthia Zwick
1940 East Luke Avenue
Phoenix, Arizona 85016
Intervenor

Lawrence V. Robertson, Jr., Esq.
Attorney at Law
P.O. Box 1448
Tubac, Arizona 85646
Attorney for Intervenors SWPG/Bowie and Noble/Constellation/Direct/Shell

Laura E. Sanchez, Esq.
NRDC
P.O. Box 287
Albuquerque, New Mexico 87103
Attorney for Intervenor NRDC

Jay I. Moyes, Esq.
Steve Wene, Esq.
Moyes, Sellers & Hendricks
1850 N. Central Ave., Suite 1100
Phoenix, Arizona 85004
Attorneys for Intervenor AzAg

Jeffrey J. Woner
K.R. Saline & Assoc., PLC
160 N. Pasadena, Suite 101
Mesa, Arizona 85201
Consultant for Intervenor AzAg

Scott S. Wakefield, Esq.
Ridenour, Hienton & Lewis, P.L.L.C.
201 N. Central Avenue, Suite 3300
Phoenix, Arizona 85004
Attorney for Intervenor Wal-Mart

Steve W. Chriss
Senior Manager, Energy Regulatory Analysis
Wal-Mart Stores, Inc.
2011 S.E. 10th St.
Bentonville, Arkansas 72716
Representative for Intervenor Wal-Mart

Craig A. Marks, Esq.
Craig A. Marks, PLC
10645 N. Tatum Blvd, Ste. 200-676
Phoenix, Arizona 85028
Attorney for Intervenor AARP

Jeff Schlegel
1167 W. Samalayuca Dr.
Tucson, Arizona 85704
Representative for Intervenor SWEEP

**Q1. PLEASE STATE YOUR NAME AND POSITION.**

A1. G. David Vandever. I am the Business Manager of IBEW Local 387, which is, among other things, the exclusive bargaining representative of approximately one-thousand nine-hundred (1,900) non-managerial employees of APS.

**Q2. ARE YOU THE SAME G. DAVID VANDEVER WHOSE DIRECT TESTIMONY WAS FILED IN THIS MATTER ON NOVEMBER 18, 2011?**

A2. Yes.

**Q3. DO YOU HAVE ANY REVISIONS, CORRECTIONS, OR UPDATES THAT YOU WOULD LIKE TO MAKE TO YOUR PREVIOUS TESTIMONY?**

A3. Yes. Many of the figures and calculations contained in my direct testimony were based on numbers provided by APS in response to our first set of data requests. Since the time of the filing of my direct testimony, APS has served a supplemental response to items 6-10 in order to correct and/or update the figures originally provided. A copy of the supplemental response is attached hereto as Exhibit A. As a result, some of the figures and calculations originally included in my direct testimony may need to be revised. Be that as it may, I believe the revised numbers still demonstrate the need to address the pressing challenges associated with the "aging workforce" problem.

**Q4. PLEASE TELL US MORE ABOUT IBEW LOCAL 640 AND THE TYPE OF WORK THE LOCAL'S MEMBERS PERFORM.**

A4. Sure. Although I am not a member of that local, I am quite familiar with it. IBEW Local 640 has represented workers in the electrical construction industry for 87 years. IBEW Local 640 has the highest caliber of skilled and trained Inside Construction Journeyman Wiremen in the State of Arizona. The Local constantly proves that point on job sites throughout the State every day to the customers it serves through the Local's approximately 75 small, medium, and large capacity signatory employers. IBEW Local 640's principal work is the construction and maintenance of commercial and industrial facilities.

**Q5. PLEASE DESCRIBE IBEW LOCAL 640'S RELATIONSHIP WITH APS AND ANY VISION THE LOCAL HAS FOR ENHANCING THE RELATIONSHIP IN THE FUTURE.**

A5. Historically, APS and IBEW Local 640 have had a relatively stable, mutually-beneficial relationship whereby the Local's members and their employers provided construction and maintenance services for many APS projects and facilities. From the statewide coal-fired plants to the Palo Verde Nuclear Generating Station to the many associated sub-stations and switching yards, IBEW Local 640's members have had a successful history of providing Arizona Public Service an outstanding level of quality and value in the construction of these facilities. In addition, a few years ago, the Local provided APS with qualified manpower for use in the Company's "residential taskforce" and stands ready to provide qualified solar installation manpower as well.

Unfortunately, at some point in the recent past, APS's interest in utilizing the services of the Local's highly-trained workforce and the associated contractors to meet its facility construction and maintenance needs seems to have waned. Although there are still a couple of associated contractors still bidding, and occasionally winning APS work, it seems that many of the contractors no longer pursue this work due to the recent, statewide trend of awarding to the lowest "responsible" bidder. The Local acknowledges that the signatory contractors are seldom the low bid or cheapest bid, but believes that, more often than not, one gets what one pays for with respect to the final product as well. IBEW Local 640 expresses its sincere hope that using the cheapest labor on every construction and maintenance project will not become the "new norm" and cautions that the use of such labor may significantly impair APS's ability to provide safe and reliable power to its customers in the long-run.

IBEW Local 640 seeks to re-establish a working relationship with APS that redounds to their mutual benefit. IBEW Local 640 emphatically does not seek to be handed work, but rather to have APS advise the Local when projects arise so that it may provide APS with two or three qualified union contractors, whose size and scope are commensurate with the project at hand, to bid on the work. IBEW Local 640 would like the opportunity for its employers to prove to APS that value trumps price and that by using its highly-skilled and trained workforce, composed primarily of local residents who earn a decent wage and benefit package and many of whom are APS customers themselves, APS receives a greater value on their construction and maintenance projects and, in turn, provides a greater value to their customers. With a new, more flexible work model in the Local's collective bargaining agreement relating to quality, efficiency, and composite value in a skill-appropriate crew mix, the Local's family of signatory contractors have the tools needed to provide even better value to the customer's bottom line than ever before.

**Q6. PLEASE PROVIDE SOME EXAMPLES OF APS PROJECTS IN WHICH IBEW LOCAL 769 MEMBERS HAVE BEEN RECENTLY ENGAGED.**

A6. Certainly. As I noted previously, IBEW Local 769 is, among other things, the exclusive bargaining agent for all IBEW outside line workers in the State of Arizona and its scope of work also includes tele-data, street light and trenching. For example, IBEW Local 769 has provided outside line construction work for APS through Wilson Construction, Klondyke, NPL, Henkels & McCoy and Sturgeon Electric, among others. At any given time, IBEW Local 769 will have anywhere from five (5) to two-hundred (200) of its bargaining unit employees working for subcontractors of APS. In the last quarter of 2011, IBEW Local 769 members and their respective employers have been contracted to provide services for APS projects across much of Arizona as follows:

- Agua Caliente Solar Project – 500 KV Switch Yard and Sub-Station, Dateland, Klondyke LLC (contractor);
- Bouse – 230 KV Harcuvar Grassroot Transmission Line, National Power Line (contractor);
- Perrin Ranch Windfarm – 500 KV Switch Yard and Sub-Station, Williams, Klondyke LLC (contractor);
- Pinnacle Peak – 500 KV-230 KV Switch Yard and Sub-Station Upgrade, Scottsdale, Wilson Utility Construction (contractor);
- 69 KV Re-Conductor, Hope, Atkinson Power (contractor); and
- several small distribution projects in Maricopa County.

**Q7. DO IBEW LOCALS 387, 640 AND 769 SUPPORT THE ADOPTION OF THE JANUARY 6, 2012 SETTLEMENT AGREEMENT?**

A7. Yes. On behalf of the more than one-thousand nine-hundred (1,900) non-managerial workers at APS who are represented by IBEW Local 387, I would like to express the Union's unqualified support for the proposed Settlement Agreement. In addition, I know that our two sister locals, IBEW Locals 640 and 769, are also fully supportive of the Settlement Agreement.

**Q8. ARE THERE SPECIFIC PORTIONS OF THE SETTLEMENT AGREEMENT THAT IBEW LOCALS 387, 640 AND 769 ARE PARTICULARLY INTERESTED IN?**

A8. Yes. While IBEW Locals 387, 640 and 769 support the adoption of proposed Settlement Agreement in its entirety, we are particularly interested in, and/or took an especially active role in negotiating or otherwise considering, the following paragraphs of the proposed Settlement Agreement: ¶¶ 1.4 and 18.2.

**Q9. PLEASE EXPLAIN WHY IBEW LOCALS 387, 640, AND 769 ARE PARTICULARLY INTERESTED IN ¶ 1.4.**

A9. IBEW Locals 387, 640, and 769 note the inclusion of Paragraph 1.4. In it, the parties simply acknowledge the fact that Article XV, § 3 of the Arizona Constitution places the interests of public service employees on par with those of patrons. The interests of both constituencies, in turn, are of more importance than those of the corporation's shareholders.

**Q10. ARE YOU AWARE OF ANY LEGAL AUTHORITY SUPPORTING THIS PROPOSITION?**

A10. Certainly. In its 1984 decision in *Cogent Pub. Serv. v. Arizona Corp. Comm'n*, 142 Ariz. 52, 56-57, 688 P.2d 698, 702-03, Division One expressly, and in my opinion, correctly, held that "the jurisprudence of our State made it plain long ago that the interests of public-service corporation stockholders must not be permitted to overshadow those of the public served." In support of this quite unremarkable proposition, our Court of Appeals relied upon a series of U.S. and Arizona Supreme Court decisions dating back to 1896.[1] Beyond that, I would also point out that while Article XV, § 3 of the Arizona Constitution mentions "employees and patrons" as key stakeholders, it does not mention shareholders as such.

**Q11. PLEASE EXPLAIN WHY IBEW LOCALS 387, 640, AND 769 ARE PARTICULARLY INTERESTED IN ¶ 18.2.**

A11. In the Application to Intervene and Direct Testimony filed on their behalf in this

---

[1] *See Salt River Valley Canal Co. v. Nelssen*, 10 Ariz. 9, 13, 85 P. 117, 119 (1906) [*citing Covington & Lexington Turnpike Road Co. v. Sanford*, 164 U.S. 578, 596 (1896)].

matter, IBEW Locals 387, 640, and 769 raised significant concerns related to APS's workforce planning moving forward and, in particular, the "aging workforce" problem that so many utilities, including APS, face and will continue to face in the years to come. Paragraph 18.2 highlights these concerns and serves to focus the parties' and the Commission's attention on these important matters – both now and going forward. The reporting requirements included in this paragraph will ensure that APS undertakes at least an annual review and assessment of its workforce planning for critical positions in light of these challenges and considers what sorts of recruitment and hiring efforts it must undertake to meet these challenges ahead of anticipated retirements. I can say, without exaggeration or hyperbole, that I firmly believe APS's ability to provide safe and reliable electric power in Arizona in the years to come depends to no small degree on the steps the Company takes to meet these impending challenges.

**Q12. ARE THERE ANY PORTIONS OF THE PROPOSED SETTLEMENT AGREEMENT WITH WHICH IBEW LOCALS 387, 640, AND 769 ARE LESS PLEASED?**

A12. Sure. We would have preferred that APS receive even more – potentially far more – rate relief than what is set forth in ¶ 3.1 of the Settlement Agreement. Notwithstanding these reservations, however, IBEW Local 387, 640, and 769 recognize that the consummation of a comprehensive Settlement Agreement among nearly two dozen different parties with often disparate and competing interests is no so small feat. It is for that reason that we fully and strongly support the Commission's adoption of the proposed Settlement Agreement *in toto*.

**Q13. DO YOU HAVE ANY OTHER COMMENTS YOU WOULD LIKE TO SHARE WITH THE COMMISSION REGARDING THE INSTANT SETTLEMENT?**

A13. Yes. I want to make it abundantly clear to the Commission and APS that, by agreeing to this Settlement Agreement, IBEW Local 387 has not, and does not, agree to any modification, express or implied, to the terms and conditions of its collective bargaining agreement with APS. That is not to say that I believe this will ever become a problem *vis-à-vis* IBEW Local 387's relationship with APS; in fact, I do not believe that is the case. Nevertheless, I just want to make certain that there is no confusion in this regard moving forward.

**Q14. DOES THIS CONCLUDE YOUR TESTIMONY?**

A14. Yes.

F:\Donetto\IBEW L. 387 1445-100.Vandever\Testimony#2.pld.wpd

aps

**JEFFREY W. JOHNSON**
Regulatory Affairs Supervisor
State Regulation

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-250-2661
Jeffrey.Johnson@aps.com

December 5, 2011

Nicholas J. Enoch
Lubin & Enoch, P.C.
349 North Fourth Avenue
Phoenix, AZ 85003

RE: Arizona Public Service Company's 2010 Test Year Rate Case
Docket No. E-01345A-11-0224

Attached please find Arizona Public Service Company's Supplemental Response to IBEW's First Set of Data Requests, Questions 6-10 in the above-referenced matter.

If you have any questions regarding this information, please contact Zachary Fryer at (602)250-4167.

Sincerely,

Jeffrey W. Johnson

JJ/sl
Attachment

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.6: Please state, for each the past five (5) calendar years, the share of retirement-eligible employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request, who opted to retire.

Supplemental Response to IBEW 1.6: Below are the percentages and number of individuals in each of the job classifications that retired from 2010 to present. The percentages have been updated to reflect the percent of actual to eligible retirements per job classification per year. Please disregard the previous submittal since there was erroneous data.

**Retirements: 2006-2010**

| Job | | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0 | 0 | 0 | 1 | 1 |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0 | 0 | 0 | 0 |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 0 | 0 | 0 | 0 | 0 |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 0 | 0 | 0 | 0 | 1 |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0 | 0 | 0 | 0 |
| Control Operator | Control Operator | 1 | 1 | 2 | 0 | 0 |
| Control Operator | Oper Control | 0 | 0 | 0 | 1 | 0 |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 0 | 0 | 0 | 3 | 0 |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 0 | 0 | 0 | 0 | 1 |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 0 | 0 | 0 | 0 | 0 |
| Electrician-Journeyman | Electrician | 1 | 7 | 6 | 0 | 0 |
| Lineman-Journeyman | Lineman Hotstick | 0 | 0 | 0 | 0 | 0 |
| Lineman-Journeyman | Lineman Journeyman | 1 | 2 | 4 | 2 | 2 |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 0 | 0 | 0 | 0 | 0 |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 0 | 0 | 0 | 0 | 2 |
| Technician-E&I | E&I Technician | 3 | 2 | 2 | 1 | 1 |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

Supplemental Response to IBEW 1.6 Continued:

**Retirements: 2006-2010**

| Job | | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0% | 0% | 0% | 33% | 100% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0% | 0% | 0% | 0% | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 0% | 0% | 0% | 0% | 0% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 0% | 0% | 0% | 0% | 14% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0% | 0% | 0% | 0% | 0% |
| Control Operator | Control Operator | 50% | 25% | 40% | 0% | 33% |
| Control Operator | Oper Control | 0% | 0% | 0% | 50% | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 0% | 0% | 0% | 33% | 14% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 0% | 0% | 0% | 0% | 19% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 0% | 0% | 0% | 0% | 0% |
| Electrician-Journeyman | Electrician | 8% | 24% | 14% | 0% | 11% |
| Lineman-Journeyman | Lineman Hotstick | 0% | 0% | 0% | 0% | 0% |
| Lineman-Journeyman | Lineman Journeyman | 5% | 5% | 6% | 3% | 7% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 0% | 0% | 0% | 0% | 13% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 0% | 0% | 0% | 0% | 40% |
| Technician-E&I | E&I Technician | 100% | 40% | 67% | 17% | 33% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.7: Please state the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who are presently retirement eligible.

Supplemental Response to IBEW 1.7: Please disregard the previous submittal since there was erroneous data.

**Retirement Eligibility Summary**

| Job | | Current (9/30/11) | Current (9/30/11) |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0 | 0% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 2 | 28% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 23 | 21% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 0 | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 7 | 29% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 13 | 26% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 1 | 100% |
| Electrician-Journeyman | Electrician | 11 | 10% |
| Lineman-Journeyman | Lineman Hotstick | 4 | 27% |
| Lineman-Journeyman | Lineman Journeyman | 22 | 12% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 13 | 45% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 5 | 29% |
| Technician-E&I | E&I Technician | 8 | 15% |

Witness: Daniel T. Froetscher

# IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-11-0224 OCTOBER 26, 2011

IBEW 1.8: Please state: (1) the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who will be retirement eligible between the present and December 31,2012; and (2) anticipated hiring and attrition levels for each of the job classifications referenced in the preceding data request between the present and December 31, 2012.

Supplemental Response to IBEW 1.8: APS provides the following information on retirement eligibility between September 30, 2011 and December 31, 2012 and does not have information to respond to anticipated hiring and attrition levels. Please disregard the previous submittal since there was erroneous data.

**Retirement Eligibility Summary**

| Job | | 9/30/11 - 12/31/12 | 9/30/11 - 12/31/12 |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 0 | 0% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 2 | 25% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 29 | 26% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 0 | 0% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 9 | 38% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 15 | 30% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 1 | 100% |
| Electrician-Journeyman | Electrician | 13 | 12% |
| Lineman-Journeyman | Lineman Hotstick | 4 | 27% |
| Lineman-Journeyman | Lineman Journeyman | 27 | 15% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 15 | 52% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 6 | 35% |
| Technician-E&I | E&I Technician | 9 | 17% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.9: Please state: (1) the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who will be retirement eligible between January 1,2013, and December 31, 2014; and (2) anticipated hiring and attrition levels for each of the job classifications referenced in the preceding data request between January 1,2013, and December 31, 2014.

Supplemental Response to IBEW 1.9: APS provides the following information on retirement eligibility between January 1, 2013 and December 31, 2014 and does not have information to respond to anticipated hiring and attrition levels. Please disregard the previous submittal since there was erroneous data.

**Retirement Eligibility Summary**

| | Job | 1/1/13 - 12/31/14 | 1/1/13 - 12/31/14 |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 1 | 100% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 3 | 38% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 40 | 36% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 1 | 100% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 12 | 50% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 21 | 42% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 1 | 100% |
| Electrician-Journeyman | Electrician | 26 | 23% |
| Lineman-Journeyman | Lineman Hotstick | 4 | 27% |
| Lineman-Journeyman | Lineman Journeyman | 40 | 22% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 17 | 59% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 11 | 65% |
| Technician-E&I | E&I Technician | 16 | 30% |

Witness: Daniel T. Froetscher

IBEW LOCALS 387, 640 and 769 FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 26, 2011

IBEW 1.10: Please state: (1) the share of employees, both as a percentage and in absolute terms, in each of the job classifications referenced in the preceding data request who will be retirement eligible between January 1,2015, and December 31,2016; and (2) anticipated hiring and attrition levels for each of the job classifications referenced in the preceding data request between January 1,2015, and December 31,2016.

Supplemental Response to IBEW 1.10: APS provides the following information on retirement eligibility between January 1, 2015 and December 31, 2016 and does not have information to respond to anticipated hiring and attrition levels. Please disregard the previous submittal since there was erroneous data.

**Retirement Eligibility Summary**

| Job | | 1/1/14 - 12/31/16 | 1/1/14 - 12/31/16 |
|---|---|---|---|
| Auxiliary Operators | Oper Auxiliaries | 1 | 100% |
| Auxiliary Operators | Ops Tech Trainee T-1 | 0 | 0% |
| Auxiliary Operators | OTTRNEET1 CONTROL OP/MECH MNTC | 5 | 63% |
| Auxiliary Operators | PS3T2 AO / MECH MNTC | 51 | 46% |
| Auxiliary Operators | PS3T2 MECH MNTC / AO | 0 | 0% |
| Control Operator | Control Operator | 0 | 0% |
| Control Operator | Oper Control | 1 | 100% |
| Control Operator | OPS TECH CONTROL OP/ INT INSTR | 15 | 63% |
| Control Operator | OPS TECH CONTROL OP/ MECH MNTC | 28 | 56% |
| Control Operator | OPS TECH CONTROL OP/PLATE WELD | 1 | 100% |
| Electrician-Journeyman | Electrician | 37 | 33% |
| Lineman-Journeyman | Lineman Hotstick | 4 | 27% |
| Lineman-Journeyman | Lineman Journeyman | 53 | 29% |
| Technician-E&I | E&I TECH ELECT / ADV INSTR | 17 | 59% |
| Technician-E&I | E&I TECH INSTR REPR/ADV ELECT | 13 | 76% |
| Technician-E&I | E&I Technician | 25 | 46% |

Witness: Daniel T. Froetscher

Kroger Ex. 1

ORIGINAL

# BOEHM, KURTZ & LOWRY

ATTORNEYS AT LAW
36 EAST SEVENTH STREET
SUITE 1510
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255

TELECOPIER (513) 421-2764

RECEIVED

2011 NOV 18 P 2:13

AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
DOCKETED

NOV 18 2011

DOCKETED BY

**Via Overnight Mail**

November 17, 2011

Arizona Corporation Commission
Attn: Docket Filing Window
1200 West Washington Street
Phoenix, AZ 85007

EXHIBIT
Kroger 1
ADMITTED

***Re: Docket No. E-01345A-11-0224***

Dear Sir or Madam:

Attached please find the original and 13 copies each of the DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON on behalf of THE KROGER CO. for filing in the above-referenced matter.

All parties of record have been served. Please place this document of file.

Very Truly Yours,

Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

John William Moore, Jr., (Az. Bar No. 021942)

**COUNSEL FOR THE KROGER CO.**

KJB/kew
Attachments

G:\WORK\MLK\KROGER\ARIZONA\E-01345A-11-0224 (Arizona Public Service)\Commission ltr.docx

## CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by electronic mail (when available) and regular U.S. mail 17th day of November, 2011 on the parties listed below.

Kurt J. Boehm, Esq.
John William Moore., Jr., (Az Bar NO. 021942)

| Company | Contact | Address |
|---|---|---|
| | Mel Beard | 4108 W. Calle Lejos<br>Glendale, Arizona 85310 |
| | Steve Chriss | 2011 S.E. 10th St.<br>Bentonville, Arkansas 72716-0500 |
| | Craig Marks | 10645 N. Tatum Blvd.<br>Suite 200-676<br>Phoenix, Arizona 85028 |
| | Scott Wakefield | 201 N. Central Ave., Suite 3300<br>Phoenix, Arizona 85004-1052 |
| | Jay Moyes | 1850 N. Central Ave. - 1100<br>Phoenix, Arizona 85004 |
| | Jeffrey Woner | K.R. SALINE & ASSOC., PLC<br>160 N. Pasadena, Suite 101<br>Mesa, Arizona 85201 |
| | Lawrence Robertson, Jr. | PO Box 1448<br>Tubac, Arizona 85646 |
| | Laura Sanchez | P.O. Box 287<br>Albuquerque, New Mexico 87103 |
| | Nicholas Enoch | 349 N. Fourth Ave.<br>Phoenix, Arizona 85003 |
| | Greg Patterson | 2398 E. Camelback Rd., Ste. 240<br>Phoenix, Arizona 85016 |
| | Karen White | AFLOA/JACL-ULT<br>139 Barnes Drive<br>Tyndall Air Force Base, Florida 32403 |
| | Gary Yaquinto | Arizona Utiltiy Investors Association<br>2100 North Central Avenue, Suite 210<br>Phoenix, Arizona 85004 |
| | Michael Grant | 2575 E. Camelback Rd.<br>Phoenix, Arizona 85016-9225 |
| | Jeffrey Crockett | One E. Washington St., Ste. 2400<br>Phoenix, Arizona 85004 |
| | Michael Patten | 400 E. Van Buren St. - 800<br>Phoenix, Arizona 85004-3906 |
| | Cynthia Zwick | 1940 E. Luke Avenue<br>Phoenix, Arizona 85016 |
| | John Moore, Jr. | 7321 N. 16th Street<br>Phoenix, Arizona 85020 |

| | | |
|---|---|---|
| | Bradley Carroll | One South Church Ave., Ste. UE201<br>Tucson, Arizona 85701 |
| | Timothy Hogan | 202 E. McDowell Rd. - 153<br>Phoenix, Arizona 85004 |
| | David Berry | P.O. Box 1064<br>Scottsdale, Arizona 85252-1064 |
| | Barbara Wyllie-Pecora | 14410 W. Gunsight Dr.<br>Sun City West, Arizona 85375 |
| | Michael Curtis | 501 East Thomas Road<br>Phoenix, Arizona 85012-3205 |
| | Daniel Pozefsky | 1110 West Washington, Suite 220<br>Phoenix, Arizona 85007 |
| | C. Webb Crockett | 3003 N. Central Ave. - 2600<br>Phoenix, Arizona 85012-2913 |
| | Janice Alward | 1200 W. Washington<br>Phoenix, Arizona 85007 |
| | Steve Olea | 1200 W. Washington St.<br>Phoenix, Arizona 85007 |
| Arizona Corporation Commission | Lyn Farmer | 1200 W. Washington<br>Phoenix, Arizona 85007-2927 |
| | Meghan Grabel | P.O. Box 53999, Station 8695<br>Phoenix, Arizona 85072-3999 |

**BEFORE THE ARIZONA CORPORATION COMMISSION**

RECEIVED

2011 NOV 18 P 2: 13

AZ CORP COMMISSION
DOCKET CONTROL

**COMMISSIONERS**

**GARY PIERCE, CHAIRMAN**
**BOB STUMP**
**SANDRA D. KENNEDY**
**PAUL NEWMAN**
**BRENDA BURNS**

| | |
|---|---|
| **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-11-0224** |

**DIRECT TESTIMONY**

**AND EXHIBITS**

**OF**

**STEPHEN J. BARON**

**ON**

**DECOUPLING ISSUES**

**ON BEHALF OF THE**

**KROGER CO.**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**November 2011**

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | | |
|---|---|---|
| **IN THE MATTER OF THE APPLICATION OF** | **)** | |
| **ARIZONA PUBLIC SERVICE COMPANY FOR** | **)** | |
| **A HEARING TO DETERMINE THE FAIR VALUE** | **)** | |
| **OF THE UTILITY PROPERTY OF THE COMPANY** | **)** | **Docket No. E-01345A-11-0224** |
| **FOR RATEMAKING PURPOSES, TO FIX A JUST** | **)** | |
| **AND REASONABLE RATE OF RETURN** | **)** | |
| **THEREON, TO APPROVE RATE SCHEDULES** | **)** | |
| **DESIGNED TO DEVELOP SUCH RETURN** | **)** | |

## TABLE OF CONTENTS

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN** | **) Docket No. E-01345A-11-0224** |

# DIRECT TESTIMONY OF STEPHEN J. BARON

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

**Q. What is your occupation and by who are you employed?**

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

**Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.**

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

**Q. Please state your educational background.**

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

**Q. Please describe your professional experience.**

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit___(SJB-1).

**Q. Have you previously presented testimony before the Arizona Corporation Commission?**

A. Yes. I presented testimony in three previous Arizona Public Service Company rate cases on behalf of Kroger Co. in 2004, 2006 and in 2008 (Docket Nos. E-01345-03-0437, E-01345A-05-0816 and E-01345A-08-0172). I also presented testimony in two Tucson Electric Power Company proceedings; in 1981 on behalf of the Commission (Docket No. U-1933I) and in 2008 on behalf of Kroger Co. (Docket No. E-01933A-07-0402).

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Kroger Co. Kroger has approximately 36 stores in the APS service territory operating under the names Fry's, Fred Meyer and Smith's. These stores consume in excess of 100 million kWhs per year on the APS system.

**Q. What is the purpose of your testimony?**

A. I will be presenting testimony in response to the Direct Testimony of APS witness Leland Snook regarding the implementation of a decoupling tariff, which the Company has designated as an Energy and Infrastructure Account ("EIA") mechanism. As discussed in Mr. Snook's testimony, APS is requesting a "revenue per customer decoupling mechanism" that would impose additional charges on retail customers ostensibly associated with lost sales from energy efficiency programs. As I will discuss, the EIA should be rejected because it unreasonably adds additional charges on customer bills over and above cost of service. Even with the proposed 3% annual CAP, the EIA will result in annual revenue increases that will not be verifiable, beyond the simplified assumption that the Company will experience financial harm if average kWh usage per customer declines (for whatever reason), compared to test year levels.

I will also recommend modifications to the Company's specific proposed EIA rate recovery mechanism, in the event that the Commission decides to approve a decoupling tariff in this case. Specifically, I will recommend that large commercial customers taking service on Rate E-32 L (over 400 kW demand) and large industrial customers taking service on Rates E-34 and E-35 be exempted from the EIA mechanism. As I will show, with the Company's proposed modifications to the E-32 L rate design, the percentage of non-fuel, non-transmission revenues recovered via a kWh charge for Rate E-32 L is approximately 40%, compared to the 74% under the present rate design. This significantly reduces the revenue risk to the Company as a result of energy conservation.

Finally, I will recommend that the EIA rate recovery factor be computed on the basis of non-fuel base revenues, rather than on total revenues as recommended by APS. Since the purpose of the EIA is to recover lost fixed cost related revenues, it is reasonable and appropriate to formulate the recovery mechanism so that the EIA lost revenue factor is applied to the fixed revenue portion of customer bills.

## II. PROPOSED EIA REVENUE DECOUPLING MECHANISM

**Q. Have you reviewed the Company's proposed EIA decoupling mechanism that is discussed in the testimony of APS witness Leland Snook?**

A. Yes. The Company is proposing a rate decoupling mechanism that is designed to recover the test year level of fixed costs per customer, irrespective of the level of kWh sales in a future period. In so doing, the Company argues that the pursuit of energy conservation (which, all else being equal results in lower kWh sales) will be "decoupled" from the profit maximizing behavior otherwise influencing the Company to sell more energy.

**Q. Would you describe the EIA mechanism proposed by APS?**

A. The EIA mechanism computes a test year level of "fixed cost" related revenue per customer for each rate class. This is the fixed cost revenue target per customer that the EIA mechanism attempts to achieve each year, following a base rate case. In each period following the test year, the Company will develop a current year "allowed fixed cost recovery" by multiplying the test year based "fixed cost revenue per customer" by the actual current year number of customers. This becomes the target revenue amount that APS argues should be recovered each year from customers. The calculation is performed separately for each rate class and ostensibly reflects the level of fixed cost revenue requirements that the Company claims that it is entitled to recover.

This amount (the target fixed cost revenue) is then compared to the "actual" current year fixed costs recovered from customers through a separate calculation termed the "actual fixed costs recovered." This "actual fixed cost recovered" calculation is based on the <u>product</u> of the test year level of fixed revenue requirements per kWh for each rate class <u>and</u> the actual current year level of kWh usage by rate class. This calculation is designed to reflect the actual level of fixed costs being recovered by the Company in any future period. The assumption is that each kWh sold produces a specified level of fixed cost revenue recovery – to determine the total fixed costs actually recovered in any future period, the test year based factor (fixed cost per kWh) is multiplied times the kWh sales in the period.

The calculation is performed on a rate class basis. The difference between the "allowed fixed cost recovery" and the "actual fixed cost recovery" is the EIA revenue adjustment for the current period. This lost revenue amount is converted to a percentage factor that is then charged to customers on a uniform basis to all customer classes. The uniform percentage is computed as a ratio of the lost revenues and total retail revenues. Finally, APS proposes to cap the factor at 3% each year, deferring any unrecovered amounts.

**Q. Do you have any concerns with the Company's proposal?**

A. Yes. I have identified a number of problems with the EIA decoupling proposal. First, I don't believe that a decoupling mechanism is necessary in order to implement an effective energy conservation program. Second, large customer classes whose rates recover a significant percentage of revenues through fixed, demand charges rather than kWh energy charges are being included in the EIA proposal. The proposed EIA makes no distinction between such customers despite large differences in the revenue risk between large customers who are subject to relatively stable kW demand charges to recover fixed costs and smaller residential customers who pay for fixed revenue requirements primarily through kWh energy charges. Customers on these demand metered rates (E-32 L, E-34 and E-35) should not be included in the decoupling mechanism.

Finally, if the Commission does approve a decoupling mechanism, the lost fixed cost revenue factor should be based only on the non-fuel, non-transmission portion of customer bills, not the total bill as proposed by APS. Since the purpose of the proposal is to recover fixed cost related revenues, it is appropriate to apply the "lost revenue factor" only to the fixed cost portion of customer bills, not the total bill that includes fuel charges and transmission charges.

**Q. Should the Company's EIA decoupling mechanism be approved by the Commission?**

A. No. While a decoupling mechanism is designed to protect the Company from earnings shortfalls that might be caused by energy efficiency programs, the APS proposed decoupling mechanism itself has nothing to do with earnings. Recovering fixed costs is not a standalone ratemaking objective. Rather, the opportunity to earn a fair rate of return on investment is the appropriate objective. The recovery of test year fixed revenue requirements per customer through the requested EIA mechanism does not insure that APS will earn a fair rate of return in any future period – it does insure that the Company will earn a larger rate of return than otherwise would be the case.[1] The EIA decoupling mechanism does not distinguish between kWh sales "lost" because of energy conservation or "lost" for any other reason, such as the loss of a large customer whose level of kWh use is significantly higher than the rate class average. For example, the average energy use per customer on Rate E-32 L is 3,524 mWh per year. A 600 kW customer with an 85% load factor would use about 4,468 mWh per year. If this customer were to leave the system in a future period, the EIA mechanism would treat this E-32 L revenue loss as a "conservation induced loss." Change in customer usage patterns unrelated to energy efficiency programs have always occurred in the electric utility industry, especially on large customer rates such as E-32 L. This is the type of risk that utilities typically face, and for which they receive compensation through a rate of return on equity in excess of a risk free rate of return. Mr. Snook, in his testimony briefly addresses this issue, but dismisses

[1] Of course, it is possible that the EIA factor could be negative, though this is not the expected outcome.

it on the basis that utilities with decoupling mechanisms typically have an ROE "that is at or in excess of APS's proposed ROE."[2] Notwithstanding this comparison with other utilities, it is simply common sense that the Company's risk would be reduced if it is permitted to recovered "allowed fixed costs" in future periods, regardless of the source of the lost revenues (i.e., whether the revenues are lost as a result of energy efficiency or some other unrelated factor). The Company's decoupling proposal does not distinguish between energy conservation induced changes in sales and any other factor, such as weather, technology changes, economic activity and the mix of customers within rate classes.

Another problem with the decoupling proposal is that it assumes that the test year level of fixed revenues is the appropriate level in any post test year period. The EIA mechanism effectively becomes a single issue rate case that does not address possible changes in the Company's cost structure in the future period. The Company claims that its earnings will be adversely affected by energy efficiency programs, yet the EIA mechanism does not address earnings at all. In addition to possible changes in the Company's costs in future periods beyond the test year on which the EIA fixed cost base is established, there is nothing in the proposed mechanism that would address possible increased off-system sales profits that may

---

[2] Direct Testimony of Leland Snook at page 23, line 8.

be available in the event that kWh sales per customer are actually below test year levels.

**Q. Are there steps that the Company and the Commission can take to reduce earnings risk associated with energy conservation induced sales changes?**

A. Yes. For general service customers, the rate design can be structured to recover fixed revenue requirements through customer and demand charges, rather than through energy charges. In fact, in this rate case, APS is proposing to shift Rate E-32 L fixed cost recovery from the hours-use kWh charge to the demand charge of the rate. This would reduce the percentage of revenue that is being recovered through the E-32 L energy charges that are subject to energy conservation impacts. Such rate restructuring, to recover fixed costs through demand charges rather than thorough energy charges would reduce the impact of energy efficiency measures on fixed cost recovery. This can be accomplished without adding additional charges to customer bills.

**Q. On page 16 of his testimony, Mr. Snook states that 66% of fixed costs for commercial customers are recovered through volumetric charges. Is this true for Rate E-32 L customers based on the Company's proposed rate design?**

A. No. One of the arguments that APS uses to support its proposed EIA decoupling mechanism is that a substantial portion of its non-fuel, non-transmission revenues are recovered via kWh energy rates that are subject to energy conservation impacts that result in lost fixed cost revenue recovery. Mr. Snook prepared an analysis (LRS_WP1) that develops the percentage of non-fuel, non-transmission revenues for each rate class that are recovered on a kWh basis. His analysis shows that at present rates, 83.6% of residential Rate E-12 revenues are recovered through energy charges and that 73.3% of Rate E-32 L revenues are recovered on a kWh basis. This appears to be the basis for his testimony on page 16 and, to a certain extent, the Company's position that Rate E-32 L customers should not be exempted from the EIA mechanism. However, Mr. Snook based his analysis on the present Rate E-32 L rate design, not on the Company's proposed rate design that shifts a substantial amount of fixed cost revenue recovery from the kWh charges of the rate to the demand charge. Based on the Company's proposed E-32 L rate design, <u>only 38.9% of fixed costs are recovered via an energy charge</u>, not the 73.3% used in Mr. Snook's analysis. Again, this must be compared to the <u>83.6% of fixed cost revenues recovered through the energy charge of residential Rate E-12</u>. The lost revenue risk associated with energy efficiency sales reductions for Rate E-32 L will be substantially reduced under the Company's proposed rate design.

Q. **Based on the APS proposed restructuring of Rate E-32 L, should this rate be excluded from the EIA decoupling mechanism, assuming that the EIA mechanism is approved by the Commission?**

A. Yes. While Mr. Snook appears to acknowledge that Rates E-34 and E-35 recover a substantial portion of non-fuel revenues via a demand charge and therefore could be excluded from the EIA decoupling mechanism with some additional rate design modifications, he disagrees that Rate E-32 L can be excluded. In light of the restructuring proposal for Rate E-32 L, which substantially reduces the amount of fixed cost revenue being recovered via the energy charges of the rate, I believe that it is appropriate to exclude Rate E-32 L from the decoupling proposal as well. I also support the exclusion of Rates E-34 and E-35 from the EIA decoupling mechanism as well.

**Q. Have you reviewed the specific formula proposed by the Company to recover lost revenues from rate classes?**

A. Yes. The proposed EIA mechanism computes lost fixed cost related revenues on a class by class basis, sums these amounts across all rate classes and computes a uniform percentage factor that is based on total retail revenues, including fuel and transmission revenues. The resulting factor would then be applied to a customer's total bill, which includes fuel and transmission revenues.

**Q. Do you have any concerns with the formulation of the EIA rate recovery factor based on total revenues?**

A. Yes. Notwithstanding my previous recommendations to reject the EIA mechanism and, if it is approved, to exclude Rates E-32 L, E-34 and E-35, the rate recovery mechanism should be revised to compute the factor as a percentage of base revenues less fuel and transmission revenues. Since the intended purposes of the EIA decoupling mechanism is to stabilize fixed cost recovery, it is appropriate to apply the EIA recovery factor only to customer non-fuel, non-transmission revenues rather than total revenues. Since only fixed cost related revenues are at issue in the EIA recovery charge, the level of a customer's fuel and transmission revenues should not determine the amount of the EIA paid by the customer. Yet under the Company's proposal, the EAI factor is applied to a customer's total bill, including fuel and transmission charges. This is particularly important if high load factor customers on Rates E-32 L, E-34 and E-35 are required to participate since the uniform factor being proposed by APS makes no distinction among rate classes with regard to the percentage of fixed cost related revenues that are recovered via energy charges.

**Q. Does that complete your testimony?**

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) |
| ARIZONA PUBLIC SERVICE COMPANY FOR | ) |
| A HEARING TO DETERMINE THE FAIR VALUE | ) |
| OF THE UTILITY PROPERTY OF THE COMPANY | ) Docket No. E-01345A-11-0224 |
| FOR RATEMAKING PURPOSES, TO FIX A JUST | ) |
| AND REASONABLE RATE OF RETURN | ) |
| THEREON, TO APPROVE RATE SCHEDULES | ) |
| DESIGNED TO DEVELOP SUCH RETURN | ) |

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

# AFFIDAVIT

STATE OF GEORGIA )

COUNTY OF FULTON )

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
15th day of November 2011.

Jessica K. In

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 4/81 | 203(B) | KY | Louisville Gas & Electric Co. | Louisville Gas & Electric Co. | Cost-of-service. |
| 4/81 | ER-81-42 | MO | Kansas City Power & Light Co. | Kansas City Power & Light Co. | Forecasting. |
| 6/81 | U-1933 | AZ | Arizona Corporation Commission | Tucson Electric Co. | Forecasting planning. |
| 2/84 | 8924 | KY | Airco Carbide | Louisville Gas & Electric Co. | Revenue requirements, cost-of-service, forecasting, weather normalization. |
| 3/84 | 84-038-U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Excess capacity, cost-of-service, rate design. |
| 5/84 | 830470-EI | FL | Florida Industrial Power Users' Group | Florida Power Corp. | Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility. |
| 10/84 | 84-199-U | AR | Arkansas Electric Energy Consumers | Arkansas Power and Light Co. | Cost allocation and rate design. |
| 11/84 | R-842651 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Interruptible rates, excess capacity, and phase-in. |
| 1/85 | 85-65 | ME | Airco Industrial Gases | Central Maine Power Co. | Interruptible rate design. |
| 2/85 | I-840381 | PA | Philadelphia Area Industrial Energy Users' Group | Philadelphia Electric Co. | Load and energy forecast. |
| 3/85 | 9243 | KY | Alcan Aluminum Corp., et al. | Louisville Gas & Electric Co. | Economics of completing fossil generating unit. |
| 3/85 | 3498-U | GA | Attorney General | Georgia Power Co. | Load and energy forecasting, generation planning economics. |
| 3/85 | R-842632 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 5/85 | 84-249 | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design return multipliers. |
| 5/85 | | City of | Chamber of | Santa Clara | Cost-of-service, rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | Santa Clara | Commerce | Municipal | |
| 6/85 | 84-768-E-42T | WV | West Virginia Industrial Intervenors | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 6/85 | E-7 Sub 391 | NC | Carolina Industrials (CIGFUR III) | Duke Power Co. | Cost-of-service, rate design, interruptible rate design. |
| 7/85 | 29046 | NY | Industrial Energy Users Association | Orange and Rockland Utilities | Cost-of-service, rate design. |
| 10/85 | 85-043-U | AR | Arkansas Gas Consumers | Arkla, Inc. | Regulatory policy, gas cost-of-service, rate design. |
| 10/85 | 85-63 | ME | Airco Industrial Gases | Central Maine Power Co. | Feasibility of interruptible rates, avoided cost. |
| 2/85 | ER-8507698 | NJ | Air Products and Chemicals | Jersey Central Power & Light Co. | Rate design. |
| 3/85 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve, prudence, off-system sales guarantee plan. |
| 2/86 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve margins, prudence, off-system sales guarantee plan. |
| 3/86 | 85-299U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design, revenue distribution. |
| 3/86 | 85-726-EL-AIR | OH | Industrial Electric Consumers Group | Ohio Power Co. | Cost-of-service, rate design, interruptible rates. |
| 5/86 | 86-081-E-GI | WV | West Virginia Energy Users Group | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 8/86 | E-7 Sub 408 | NC | Carolina Industrial Energy Consumers | Duke Power Co. | Cost-of-service, rate design, interruptible rates. |
| 10/86 | U-17378 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Excess capacity, economic analysis of purchased power. |
| 12/86 | 38063 | IN | Industrial Energy | Indiana & Michigan | Interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Consumers | Power Co. | |
| 3/87 | EL-86-53-001 EL-86-57-001 | Federal Energy Regulatory Commission (FERC) | Louisiana Public Service Commission Staff | Gulf States Utilities, Southern Co. | Cost/benefit analysis of unit power sales contract. |
| 4/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Load forecasting and imprudence damages, River Bend Nuclear unit. |
| 5/87 | 87-023-E-C | WV | Airco Industrial Gases | Monongahela Power Co. | Interruptible rates. |
| 5/87 | 87-072-E-G1 | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims. |
| 5/87 | 86-524-E-SC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic dispatching of pumped storage hydro unit. |
| 5/87 | 9781 | KY | Kentucky Industrial Energy Consumers | Louisville Gas & Electric Co. | Analysis of impact of 1986 Tax Reform Act. |
| 6/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning. |
| 6/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Phase-in plan for River Bend Nuclear unit. |
| 7/87 | 85-10-22 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Methodology for refunding rate moderation fund. |
| 8/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Test year sales and revenue forecast. |
| 9/87 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Excess capacity, reliability of generating system. |
| 10/87 | R-870651 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Interruptible rate, cost-of-service, revenue allocation, rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 10/87 | I-860025 | PA | Pennsylvania Industrial Intervenors | | Proposed rules for cogeneration, avoided cost, rate recovery. |
| 10/87 | E-015/ GR-87-223 | MN | Taconite Intervenors | Minnesota Power & Light Co. | Excess capacity, power and cost-of-service, rate design. |
| 10/87 | 8702-EI | FL | Occidental Chemical Corp. | Florida Power Corp. | Revenue forecasting, weather normalization. |
| 12/87 | 87-07-01 | CT | Connecticut Industrial Energy Consumers | Connecticut Light Power Co. | Excess capacity, nuclear plant phase-in. |
| 3/88 | 10064 | KY | Kentucky Industrial Energy Consumers | Louisville Gas & Electric Co. | Revenue forecast, weather normalization rate treatment of cancelled plant. |
| 3/88 | 87-183-TF | AR | Arkansas Electric Consumers | Arkansas Power & Light Co. | Standby/backup electric rates. |
| 5/88 | 870171C001 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Cogeneration deferral mechanism, modification of energy cost recovery (ECR). |
| 6/88 | 870172C005 | PA | GPU Industrial Intervenors | Pennsylvania Electric Co. | Cogeneration deferral mechanism, modification of energy cost recovery (ECR). |
| 7/88 | 88-171-EL-AIR 88-170-EL-AIR Interim Rate Case | OH | Industrial Energy Consumers | Cleveland Electric/ Toledo Edison | Financial analysis/need for interim rate relief. |
| 7/88 | Appeal of PSC | 19th Judicial Docket U-17282 | Louisiana Public Service Commission Circuit *Court of Louisiana* | Gulf States Utilities | Load forecasting, imprudence damages. |
| 11/88 | R-880989 | PA | United States Steel | Carnegie Gas | Gas cost-of-service, rate design. |
| 11/88 | 88-171-EL-AIR 88-170-EL-AIR | OH | Industrial Energy Consumers | Cleveland Electric/ Toledo Edison. General Rate Case. | Weather normalization of peak loads, excess capacity, regulatory policy. |
| 3/89 | 870216/283 284/286 | PA | Armco Advanced Materials Corp., | West Penn Power Co. | Calculated avoided capacity, recovery of capacity payments. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Allegheny Ludlum Corp. | | |
| 8/89 | 8555 | TX | Occidental Chemical Corp. | Houston Lighting & Power Co. | Cost-of-service, rate design. |
| 8/89 | 3840-U | GA | Georgia Public Service Commission | Georgia Power Co. | Revenue forecasting, weather normalization. |
| 9/89 | 2087 | NM | Attorney General of New Mexico | Public Service Co. of New Mexico | Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting. |
| 10/89 | 2262 | NM | New Mexico Industrial Energy Consumers | Public Service Co. of New Mexico | Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost. |
| 11/89 | 38728 | IN | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates. |
| 1/90 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Jurisdictional cost allocation, O&M expense analysis. |
| 5/90 | 890366 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Non-utility generator cost recovery. |
| 6/90 | R-901609 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Allocation of QF demand charges in the fuel cost, cost-of-service, rate design. |
| 9/90 | 8278 | MD | Maryland Industrial Group | Baltimore Gas & Electric Co. | Cost-of-service, rate design, revenue allocation. |
| 12/90 | U-9346 Rebuttal | MI | Association of Businesses Advocating Tariff Equity | Consumers Power Co. | Demand-side management, environmental externalities. |
| 12/90 | U-17282 Phase IV | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Revenue requirements, jurisdictional allocation. |
| 12/90 | 90-205 | ME | Airco Industrial Gases | Central Maine Power Co. | Investigation into interruptible service and rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 1/91 | 90-12-03 Interim | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Interim rate relief, financial analysis, class revenue allocation. |
| 5/91 | 90-12-03 Phase II | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Revenue requirements, cost-of-service, rate design, demand-side management. |
| 8/91 | E-7, SUB SUB 487 | NC | North Carolina Industrial Energy Consumers | Duke Power Co. | Revenue requirements, cost allocation, rate design, demand-side management. |
| 8/91 | 8341 Phase I | MD | Westvaco Corp. | Potomac Edison Co. | Cost allocation, rate design, 1990 Clean Air Act Amendments. |
| 8/91 | 91-372 EL-UNC | OH | Armco Steel Co., L.P. | Cincinnati Gas & Electric Co. | Economic analysis of cogeneration, avoid cost rate. |
| 9/91 | P-910511 P-910512 | PA | Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group | West Penn Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 9/91 | 91-231 -E-NC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 | 8341 - Phase II | MD | Westvaco Corp. | Potomac Edison Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Results of comprehensive management audit. |
| Note: No testimony was prefiled on this. | | | | | |
| 11/91 | U-17949 Subdocket A | LA | Louisiana Public Service Commission Staff | South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co. | Analysis of South Central Bell's restructuring and |
| 12/91 | 91-410-EL-AIR | OH | Armco Steel Co., Air Products & Chemicals, Inc. | Cincinnati Gas & Electric Co. | Rate design, interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 12/91 | P-880286 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Evaluation of appropriate avoided capacity costs - QF projects. |
| 1/92 | C-913424 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Industrial interruptible rate. |
| 6/92 | 92-02-19 | CT | Connecticut Industrial Energy Consumers | Yankee Gas Co. | Rate design. |
| 8/92 | 2437 | NM | New Mexico Industrial Intervenors | Public Service Co. of New Mexico | Cost-of-service. |
| 8/92 | R-00922314 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Cost-of-service, rate design, energy cost rate. |
| 9/92 | 39314 | ID | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 10/92 | M-00920312 C-007 | PA | The GPU Industrial Intervenors | Pennsylvania Electric Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 12/92 | U-17949 | LA | Louisiana Public Service Commission Staff | South Central Bell Co. | Management audit. |
| 12/92 | R-00922378 | PA | Armco Advanced Materials Co. The WPP Industrial Intervenors | West Penn Power Co. | Cost-of-service, rate design, energy cost rate, $SO_2$ allowance rate treatment. |
| 1/93 | 8487 | MD | The Maryland Industrial Group | Baltimore Gas & Electric Co. | Electric cost-of-service and rate design, gas rate design (flexible rates). |
| 2/93 | E002/GR-92-1185 | MN | North Star Steel Co. Praxair, Inc. | Northern States Power Co. | Interruptible rates. |
| 4/93 | EC92 21000 ER92-806-000 (Rebuttal) | Federal Energy Regulatory Commission | Louisiana Public Service Commission Staff | Gulf States Utilities/Entergy agreement. | Merger of GSU into Entergy System; impact on system |
| 7/93 | 93-0114-E-C | WV | Airco Gases | Monongahela Power Co. | Interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 8/93 | 930759-EG | FL | Florida Industrial Power Users' Group | Generic - Electric Utilities | Cost recovery and allocation of DSM costs. |
| 9/93 | M-009 30406 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Ratemaking treatment of off-system sales revenues. |
| 11/93 | 346 | KY | Kentucky Industrial Utility Customers | Generic - Gas Utilities | Allocation of gas pipeline transition costs - FERC Order 636. |
| 12/93 | U-17735 | LA | Louisiana Public Service Commission Staff | Cajun Electric Power Cooperative | Nuclear plant prudence, forecasting, excess capacity. |
| 4/94 | E-015/ GR-94-001 | MN | Large Power Intervenors | Minnesota Power Co. | Cost allocation, rate design, rate phase-in plan. |
| 5/94 | U-20178 | LA | Louisiana Public Service Commission | Louisiana Power & Light Co. | Analysis of least cost integrated resource plan and demand-side management program. |
| 7/94 | R-00942986 | PA | Armco, Inc.; West Penn Power Industrial Intervenors | West Penn Power Co. | Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense. |
| 7/94 | 94-0035-E-42T | WV | West Virginia Energy Users Group | Monongahela Power Co. | Cost-of-service, allocation of rate increase, and rate design. |
| 8/94 | EC94 13-000 | Federal Energy Regulatory Commission | Louisiana Public Service Commission | Gulf States Utilities/Entergy | Analysis of extended reserve shutdown units and violation of system agreement by Entergy. |
| 9/94 | R-00943 081 R-00943 081C0001 | PA | Lehigh Valley Power Committee | Pennsylvania Public Utility Commission | Analysis of interruptible rate terms and conditions, availability. |
| 9/94 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Evaluation of appropriate avoided cost rate. |
| 9/94 | U-19904 | LA | Louisiana Public Service Commission | Gulf States Utilities | Revenue requirements. |
| 10/94 | 5258-U | GA | Georgia Public Service Commission | Southern Bell Telephone & Telegraph Co. | Proposals to address competition in telecommunication markets. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 11/94 | EC94-7-000<br>ER94-898-000 | FERC | Louisiana Public Service Commission | El Paso Electric and Central and Southwest | Merger economics, transmission equalization hold harmless proposals. |
| 2/95 | 941-430EG | CO | CF&I Steel, L.P. | Public Service Company of Colorado | Interruptible rates, cost-of-service. |
| 4/95 | R-00943271 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Cost-of-service, allocation of rate increase, rate design, interruptible rates. |
| 6/95 | C-00913424<br>C-00946104 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Interruptible rates. |
| 8/95 | ER95-112 -000 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. | Open Access Transmission Tariffs - Wholesale. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Company | Nuclear decommissioning, revenue requirements, capital structure. |
| 10/95 | ER95-1042 -000 | FERC | Louisiana Public Service Commission | System Energy Resources, Inc. | Nuclear decommissioning, revenue requirements. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Nuclear decommissioning and cost of debt capital, capital structure. |
| 11/95 | I-940032 | PA | Industrial Energy Consumers of Pennsylvania | State-wide - all utilities | Retail competition issues. |
| 7/96 | U-21496 | LA | Louisiana Public Service Commission | Central Louisiana Electric Co. | Revenue requirement analysis. |
| 7/96 | 8725 | MD | Maryland Industrial Group | Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co. | Ratemaking issues associated with a Merger. |
| 8/96 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Revenue requirements. |
| 9/96 | U-22092 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 2/97 | R-973877 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Competitive restructuring policy issues, stranded cost, transition charges. |
| 6/97 | Civil Action No. 94-11474 | US Bank-ruptcy Court Middle District of Louisiana | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Confirmation of reorganization plan; analysis of rate paths produced by competing plans. |
| 6/97 | R-973953 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 6/97 | 8738 | MD | Maryland Industrial Group | Generic | Retail competition issues |
| 7/97 | R-973954 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | 97-204 | KY | Alcan Aluminum Corp. Southwire Co. | Big River Electric Corp. | Analysis of cost of service issues - Big Rivers Restructuring Plan |
| 10/97 | R-974008 | PA | Metropolitan Edison Industrial Users | Metropolitan Edison Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | R-974009 | PA | Pennsylvania Electric Industrial Customer | Pennsylvania Electric Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 11/97 | U-22491 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |
| 11/97 | P-971265 | PA | Philadelphia Area Industrial Energy Users Group | Enron Energy Services Power, Inc./ PECO Energy | Analysis of Retail Restructuring Proposal. |
| 12/97 | R-973981 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 12/97 | R-974104 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 3/98 (Allocated Stranded Cost Issues) | U-22092 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Retail competition, stranded cost quantification. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 3/98 | U-22092 | | Louisiana Public Service Commission | Gulf States Utilities, Inc. | Stranded cost quantification, restructuring issues. |
| 9/98 | U-17735 | | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Revenue requirements analysis, weather normalization. |
| 12/98 | 8794 | MD | Maryland Industrial Group and Millennium Inorganic Chemicals Inc. | Baltimore Gas and Electric Co. | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 12/98 | U-23358 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 5/99 (Cross-Answering Testimony) | EC-98-40-000 | FERC | Louisiana Public Service Commission | American Electric Power Co. & Central South West Corp. | Merger issues related to market power mitigation proposals. |
| 5/99 (Response Testimony) | 98-426 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. | Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services. |
| 6/99 | 98-0452 | WV | West Virginia Energy Users Group | Appalachian Power, Monongahela Power, & Potomac Edison Companies | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | 99-03-35 | CT | Connecticut Industrial \Energy Consumers | United Illuminating Company | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | Adversary Proceeding No. 98-1065 | U.S. Bankruptcy Court | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Motion to dissolve preliminary injunction. |
| 7/99 | 99-03-06 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 10/99 | U-24182 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 12/99 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Ananlysi of Proposed Contract Rates, Market Rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 03/00 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Evaluation of Cooperative Power Contract Elections |
| 03/00 | 99-1658-EL-ETP | OH | AK Steel Corporation | Cincinnati Gas & Electric Co. | Electric utility restructuring, stranded cost recovery, rate Unbundling. |
| 08/00 | 98-0452 E-GI | WVA | West Virginia Energy Users Group | Appalachian Power Co. American Electric Co. | Electric utility restructuring rate unbundling. |
| 08/00 | 00-1050 E-T 00-1051-E-T | WVA | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Electric utility restructuring rate unbundling. |
| 10/00 | SOAH 473-00-1020 PUC 2234 | TX | The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities | TXU, Inc. | Electric utility restructuring rate unbundling. |
| 12/00 | U-24993 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, revenue requirements. |
| 12/00 | EL00-66-000 & ER00-2854 EL95-33-002 | LA | Louisiana Public Service Commission | Entergy Services Inc. | Inter-Company System Agreement: Modifications for retail competition, interruptible load. |
| 04/01 | U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Jurisdictional Business Separation - Texas Restructuring Plan |
| 10/01 | 14000-U | GA | Georgia Public Service Commission Adversary Staff | Georgia Power Co. | Test year revenue forecast. |
| 11/01 | U-25687 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning requirements transmission revenues. |
| 11/01 | U-25965 | LA | Louisiana Public Service Commission | Generic . | Independent Transmission Company ("Transco"). RTO rate design. |
| 03/02 | 001148-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design, resource planning and demand side management. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 06/02 | U-25965 | LA | Louisiana Public Service Commission | Entergy Gulf States Entergy Louisiana | RTO Issues |
| 07/02 | U-21453 | LA | Louisiana Public Service Commission | SWEPCO, AEP | Jurisdictional Business Sep. - Texas Restructuring Plan. |
| 08/02 | U-25888 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. Entergy Gulf States, Inc. | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 08/02 | EL01-88-000 | FERC | Louisiana Public Service Commission | Entergy Services Inc. and the Entergy Operating Companies | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 11/02 | 02S-315EG | CO | CF&I Steel & Climax Molybdenum Co. | Public Service Co. of Colorado | Fuel Adjustment Clause |
| 01/03 | U-17735 | LA | Louisiana Public Service Commission | Louisiana Coops | Contract Issues |
| 02/03 | 02S-594E | CO | Cripple Creek and Victor Gold Mining Co. | Aquila, Inc. | Revenue requirements, purchased power. |
| 04/03 | U-26527 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Weather normalization, power purchase expenses, System Agreement expenses. |
| 11/03 | ER03-753-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Tariff MSS-4. |
| 11/03 | ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002 | FERC | Louisiana Public Service Commission | Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 12/03 | U-27136 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 01/04 | E-01345-03-0437 | AZ | Kroger Company | Arizona Public Service Co. | Revenue allocation rate design. |
| 02/04 | 00032071 | PA | Duquesne Industrial Intervenors | Duquesne Light Company | Provider of last resort issues. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 03/04 | 03A-436E | CO | CF&I Steel, LP and Climax Molybedenum | Public Service Company of Colorado | Purchased Power Adjustment Clause. |
| 04/04 | 2003-00433 2003-00434 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service Rate Design |
| 0-6/04 | 03S-539E | CO | Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co. | Aquila, Inc. | Cost of Service, Rate Design Interruptible Rates |
| 06/04 | R-00049255 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 10/04 | 04S-164E | CO | CF&I Steel Company, Climax Mines | Public Service Company of Colorado | Cost of service, rate design, Interruptible Rates. |
| 03/05 | Case No. 2004-00426 Case No. 2004-00421 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities Louisville Gas & Electric Co. | Environmental cost recovery. |
| 06/05 | 050045-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design |
| 07/05 | U-28155 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc. Entergy Gulf States, Inc. | Independent Coordinator of Transmission – Cost/Benefit |
| 09/05 | Case Nos. 05-0402-E-CN 05-0750-E-PC | WVA | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Environmental cost recovery, Securitization, Financing Order |
| 01/06 | 2005-00341 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Power Company | Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism |
| 03/06 | U-22092 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |
| 04/06 | U-25116 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc. | Transmission Prudence Investigation |
| 06/06 | R-00061346 C0001-0005 | PA | Duquesne Industrial Intervenors & IECPA | Duquesne Light Co. | Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues |
| 06/06 | R-00061366 R-00061367 P-00062213 | | Met-Ed Industrial Energy Users Group and Penelec Industrial Customer | Metropolitan Edison Co. Pennsylvania Electric Co. | Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | P-00062214 | | Alliance | | |
| 07/06 | U-22092 Sub-J | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |
| 07/06 | Case No. 2006-00130 Case No. 2006-00129 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities Louisville Gas & Electric Co. | Environmental cost recovery. |
| 08/06 | Case No. PUE-2006-00065 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment |
| 09/06 | E-01345A-05-0816 | AZ | Kroger Company | Arizona Public Service Co. | Revenue alllocation, cost of service, rate design. |
| 11/06 | Doc. No. 97-01-15RE02 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power United Illuminating | Rate unbundling issues. |
| 01/07 | Case No. 06-0960-E-42T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Retail Cost of Service Revenue apportionment |
| 03/07 | U-29764 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. Entergy Louisiana, LLC | Implementation of FERC Decision Jurisdictional & Rate Class Allocation |
| 05/07 | Case No. 07-63-EL-UNC | OH | Ohio Energy Group | Ohio Power, Columbus Southern Power | Environmental Surcharge Rate Design |
| 05/07 | R-00049255 Remand | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 06/07 | R-00072155 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues. |
| 07/07 | Doc. No. 07F-037E | CO | Gateway Canyons LLC | Grand Valley Power Coop. | Distribution Line Cost Allocation |
| 09/07 | Doc. No. 05-UR-103 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Electric Power Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 11/07 | ER07-682-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues. |
| 1/08 | Doc. No. 20000-277-ER-07 | WY | Cimarex Energy Company | Rocky Mountain Power (PacifiCorp) | Vintage Pricing, Marginal Cost Pricing Projected Test Year |
| 1/08 | Case No. 07-551 | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | | | Rate Schedules |
| 2/08 | ER07-956 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 2/08 | Doc No. P-00072342 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Default Service Plan issues. |
| 3/08 | Doc No. E-01933A-05-0650 | AZ | Kroger Company | Tucson Electric Power Co. | Cost of Service, Rate Design |
| 05/08 | 08-0278 E-GI | WV | West Virginia Energy Users Group | Appalachian Power Co. American Electric Power Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 6/08 | Case No. 08-124-EL-ATA | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Recovery of Deferred Fuel Cost |
| 7/08 | Docket No. 07-035-93 | UT | Kroger Company | Rocky Mountain Power Co. | Cost of Service, Rate Design |
| 08/08 | Doc. No. 6680-UR-116 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Power and Light Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 09/08 | Doc. No. 6690-UR-119 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Public Service Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 09/08 | Case No. 08-936-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Competitive Solicitation |
| 09/08 | Case No. 08-935-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Rate Plan |
| 09/08 | Case No. 08-917-EL-SSO 08-918-EL-SSO | OH | Ohio Energy Group | Ohio Power Company Columbus Southern Power Co. | Provider of Last Resort Rate Plan |
| 10/08 | 2008-00251 2008-00252 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service, Rate Design |
| 11/08 | 08-1511 E-GI | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 11/08 | M-2008-2036188, M-2008-2036197 | PA | Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance | Metropolitan Edison Co. Pennsylvania Electric Co. | Transmission Service Charge |
| 01/09 | ER08-1056 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 01/09 | E-01345A-08-0172 | AZ | Kroger Company | Arizona Public Service Co. | Cost of Service, Rate Design |
| 02/09 | 2008-00409 | KY | Kentucky Industrial Utility Customers, Inc. | East Kentucky Power Cooperative, Inc. | Cost of Service, Rate Design |
| 5/09 | PUE-2009 -00018 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Transmission Cost Recovery Rider |
| 5/09 | 09-0177-E-GI | WV | West Virginia Energy Users Group | Appalachian Power Company | Expanded Net Energy Cost "ENEC" Analysis |
| 6/09 | PUE-2009 -00016 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Fuel Cost Recovery Rider |
| 6/09 | PUE-2009 -00038 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Company | Fuel Cost Recovery Rider |
| 7/09 | 080677-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design |
| 8/09 | U-20925 (RRF 2004) | LA | Louisiana Public Service Commission Staff | Entergy Louisiana LLC | Interruptible Rate Refund Settlement |
| 9/09 | 09AL-299E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Energy Cost Rate issues |
| 9/09 | Doc. No. 05-UR-104 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Electric Power Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 9/09 | Doc. No. 6680-UR-117 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Power and Light Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 10/09 | Docket No. 09-035-23 | UT | Kroger Company | Rocky Mountain Power Co. | Cost of Service, Allocation of Rev Increase |
| 10/09 | 09AL-299E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Cost of Service, Rate Design |
| 11/09 | PUE-2009 -00019 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Cost of Service, Rate Design |
| 11/09 | 09-1485 E-P | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 12/09 | Case No. 09-906-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Rate Plan |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 12/09 | ER09-1224 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 12/09 | Case No. PUE-2009-00030 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Allocation of Rev Increase, Rate Design |
| 2/10 | Docket No. 09-035-23 | UT | Kroger Company | Rocky Mountain Power Co. | Rate Design |
| 3/10 | Case No. 09-1352-E-42T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Retail Cost of Service Revenue apportionment |
| 3/10 | E015/ GR-09-1151 | MN | Large Power Intervenors | Minnesota Power Co. | Cost of Service, rate design |
| 4/10 | EL09-61 | FERC | Louisiana Public Service Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | System Agreement Issues Related to off-system sales |
| 4/10 | 2009-00459 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Power Company | Cost of service, rate design, transmission expenses. |
| 4/10 | 2009-00548 2009-00549 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service, Rate Design |
| 7/10 | R-2010-2161575 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Company | Cost of Service, Rate Design |
| 09/10 | 2010-00167 | KY | Kentucky Industrial Utility Customers, Inc. | East Kentucky Power Cooperative, Inc. | Cost of Service, Rate Design |
| 09/10 | 10M-245E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Economic Impact of Clean Air Act |
| 11/10 | 10-0699-E-42T | WV | West Virginia Energy Users Group | Appalachian Power Company | Cost of Service, Rate Design, Transmission Rider |
| 11/10 | Doc. No. 4220-UR-116 | WI | Wisconsin Industrial Energy Group, Inc. | Northern States Power Co. Wisconsin | Cost of Service, rate design |
| 12/10 | 10A-554EG | CO | CF&I Steel Company Climax Molybdenum | Public Service Company | Demand Side Management Issues |
| 12/10 | 10-2586-EL-SSO | OH | Ohio Energy Group | Duke Energy Ohio | Provider of Last Resort Rate Plan Electric Security Plan |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 3/11 | 20000-384-ER-10 | WY | Wyoming Industrial Energy Consumers | Rocky Mountain Power Wyoming | Electric Cost of Service, Revenue Apportionment, Rate Design |
| 6/11 | Docket No. 10-035-124 | UT | Kroger Company | Rocky Mountain Power Co. | Class Cost of Service |
| 6/11 | PUE-2011 -00045 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Fuel Cost Recovery Rider |
| 07/11 | U-29764 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. Entergy Louisiana, LLC | Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues |
| 07/11 | Case Nos. 11-346-EL-SSO 11-348-EL-SSO | OH | Ohio Energy Group | Ohio Power Company Columbus Southern Power Co. | Electric Security Rate Plan, Provider of Last Resort Issues |
| 08/11 | PUE-2011-00034 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Rate Recovery of RPS Costs |
| 09/11 | 2011-00161 2011-00162 | KY | Kentucky Industrial Utility | Louisville Gas & Electric Co. Kentucky Utilities Company | Environmental Cost Recovery |
| 09/11 | Case Nos. 11-346-EL-SSO 11-348-EL-SSO | OH | Ohio Energy Group | Ohio Power Company Columbus Southern Power Co. | Electric Security Rate Plan, Stipulation Support Testimony |
| 10/11 | 11-0452 E-P-T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Energy Efficiency/Demand Reduction Cost Recovery |
| 11/11 | 11-1274 E-P | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |

Kroger Ex. 2

ORIGINAL


BOEHM, KURTZ & LOWRY

ATTORNEYS AT LAW

36 EAST SEVENTH STREET

SUITE 1510

CINCINNATI, OHIO 45202

TELEPHONE (513) 421-2255

TELECOPIER (513) 421-2764


Arizona Corporation Commission

DOCKETED

DEC 2 2011

DOCKETED BY

**Via Overnight Mail**

December 2, 2011

RECEIVED

2011 DEC -2 P 2:29

AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
Attn: Docket Filing Window
1200 West Washington Street
Phoenix, AZ 85007

***Re: Docket No. E-01345A-11-0224***

Dear Sir or Madam:

Attached please find the original and 13 copies each of the DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON ON COST OF SERVICE/RATE DESIGN on behalf of THE KROGER CO. for filing in the above-referenced matter.

All parties of record have been served. Please place this document of file.

Very Truly Yours,

Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

John William Moore, Jr., (Az. Bar No. 021942)

**COUNSEL FOR THE KROGER CO.**

KJB/kew
Attachments

EXHIBIT

Kroger-2

ADMITTED

G:\WORK\MLK\KROGER\ARIZONA\E-01345A-11-0224 (Arizona Public Service)\Commission ltr 120211.docx

## CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by electronic mail (when available) and regular U.S. mail 2nd day of December, 2011 on the parties listed below.

Kurt J. Boehm, Esq.
John William Moore., Jr., (Az Bar NO. 021942)

| Company | Contact | Address |
|---|---|---|
| | Mel Beard | 4108 W. Calle Lejos<br>Glendale, Arizona 85310 |
| | Steve Chriss | 2011 S.E. 10th St.<br>Bentonville, Arkansas 72716-0500 |
| | Craig Marks | 10645 N. Tatum Blvd.<br>Suite 200-676<br>Phoenix, Arizona 85028 |
| | Scott Wakefield | 201 N. Central Ave., Suite 3300<br>Phoenix, Arizona 85004-1052 |
| | Jay Moyes | 1850 N. Central Ave. - 1100<br>Phoenix, Arizona 85004 |
| | Jeffrey Woner | K.R. SALINE & ASSOC., PLC<br>160 N. Pasadena, Suite 101<br>Mesa, Arizona 85201 |
| | Lawrence Robertson, Jr. | PO Box 1448<br>Tubac, Arizona 85646 |
| | Laura Sanchez | P.O. Box 287<br>Albuquerque, New Mexico 87103 |
| | Nicholas Enoch | 349 N. Fourth Ave.<br>Phoenix, Arizona 85003 |
| | Greg Patterson | 2398 E. Camelback Rd., Ste. 240<br>Phoenix, Arizona 85016 |
| | Karen White | AFLOA/JACL-ULT<br>139 Barnes Drive<br>Tyndall Air Force Base, Florida 32403 |
| | Gary Yaquinto | Arizona Utiltiy Investors Association<br>2100 North Central Avenue, Suite 210<br>Phoenix, Arizona 85004 |
| | Michael Grant | 2575 E. Camelback Rd.<br>Phoenix, Arizona 85016-9225 |
| | Jeffrey Crockett | One E. Washington St., Ste. 2400<br>Phoenix, Arizona 85004 |
| | Michael Patten | 400 E. Van Buren St. - 800<br>Phoenix, Arizona 85004-3906 |
| | Cynthia Zwick | 1940 E. Luke Avenue<br>Phoenix, Arizona 85016 |
| | John Moore, Jr. | 7321 N. 16th Street<br>Phoenix, Arizona 85020 |

| | | |
|---|---|---|
| | Bradley Carroll | One South Church Ave., Ste. UE201<br>Tucson, Arizona 85701 |
| | Timothy Hogan | 202 E. McDowell Rd. - 153<br>Phoenix, Arizona 85004 |
| | David Berry | P.O. Box 1064<br>Scottsdale, Arizona 85252-1064 |
| | Barbara Wyllie-Pecora | 14410 W. Gunsight Dr.<br>Sun City West, Arizona 85375 |
| | Michael Curtis | 501 East Thomas Road<br>Phoenix, Arizona 85012-3205 |
| | Daniel Pozefsky | 1110 West Washington, Suite 220<br>Phoenix, Arizona 85007 |
| | C. Webb Crockett | 3003 N. Central Ave. - 2600<br>Phoenix, Arizona 85012-2913 |
| | Janice Alward | 1200 W. Washington<br>Phoenix, Arizona 85007 |
| | Steve Olea | 1200 W. Washington St.<br>Phoenix, Arizona 85007 |
| Arizona Corporation Commission | Lyn Farmer | 1200 W. Washington<br>Phoenix, Arizona 85007-2927 |
| | Meghan Grabel | P.O. Box 53999, Station 8695<br>Phoenix, Arizona 85072-3999 |

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| 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-11-0224 |

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON

COST OF SERVICE/RATE DESIGN

RECEIVED
2011 DEC -2 P 2: 29
DOCKET CONTROL

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

December 2011

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **IN THE MATTER OF THE APPLICATION OF** | **)** |
| **ARIZONA PUBLIC SERVICE COMPANY FOR** | **)** |
| **A HEARING TO DETERMINE THE FAIR VALUE** | **)** |
| **OF THE UTILITY PROPERTY OF THE COMPANY** | **) Docket No. E-01345A-11-0224** |
| **FOR RATEMAKING PURPOSES, TO FIX A JUST** | **)** |
| **AND REASONABLE RATE OF RETURN** | **)** |
| **THEREON, TO APPROVE RATE SCHEDULES** | **)** |
| **DESIGNED TO DEVELOP SUCH RETURN** | **)** |

## TABLE OF CONTENTS

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN** | **) Docket No. E-01345A-11-0224** |

**DIRECT TESTIMONY OF STEPHEN J. BARON**

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

**Q. What is your occupation and by who are you employed?**

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

**Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.**

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

**Q. Please state your educational background.**

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

**Q. Please describe your professional experience.**

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit___(SJB-1).

**Q. Have you previously presented testimony before the Arizona Corporation Commission?**

A. Yes. I presented testimony in three previous Arizona Public Service Company rate cases on behalf of Kroger Co. in 2004, 2006 and in 2008 (Docket Nos. E-01345-03-0437, E-01345A-05-0816 and E-01345A-08-0172). I also presented testimony in two Tucson Electric Power Company proceedings; in 1981 on behalf of the Commission (Docket No. U-1933I) and in 2008 on behalf of Kroger Co. (Docket No. E-01933A-07-0402).

Finally, I previously presented testimony on decoupling issues in this APS rate case.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Kroger Co. Kroger has approximately 36 stores in the APS service territory operating under the names Fry's, Fred Meyer and Smith's. These stores consume in excess of 100 million kWh per year on the APS system.

**Q. What is the purpose of your testimony?**

A. I will be presenting testimony on the Company's class cost of service study, the allocation of the proposed revenue increase to rate schedules and APS's proposed Schedule E-32 L, Large General Service rate design.

Though I believe that the Company's 4 Coincident Peak production demand allocation methodology used by APS in its jurisdictional allocation study is also the most appropriate method to allocate these demand related production costs to rate classes, I accept the Company's Average and Excess Demand method in this case.[1] The AED method provides a reasonable basis to assess cost responsibility in this case. As I will discuss, based on the Company's AED cost study, there are substantial differences between the rates paid by residential and general service customers and the cost to provide service to these customers. Specifically, the Company's own study shows that residential customers are currently receiving very substantial dollar subsidies and underpaying rates, relative to cost of service. At the same time, general service customers are paying substantial subsidies. Despite this finding, the Company's proposed increases to its Residential and General Service rate classes do not provide a material level of mitigation to this disparity between cost of service and rates. I will address this issue and recommend that the

[1] Kroger is not presenting testimony on the Company's requested revenue increase in this case. For purposes of my testimony, I have utilized the APS requested effective increase of $194 million ($95 million plus the net effect of the PSA and RES roll-ins). This should not be construed as an endorsement of the Company's requested increase.

Commission adopt an alternative rate spread that more reasonably reduces intra-class subsidies using the APS class cost of service results.

With regard to rate design, I generally agree with the Company's proposed modifications to the E-32 L rate design; specifically the proposal to eliminate the hours use kWh block in the rate and shift demand related fixed costs to the kW demand charge of this rate. As I will discuss, this proposal is consistent with cost based rate design.

**Q. Would you please summarize your recommendations?**

A.

- **For the purposes of assessing the reasonableness of the Company's proposed allocation of the revenue increase to rate schedule in this case, APS' proposal to use an Average and Excess Demand ("AED") class cost of service method is reasonable. The AED method is a traditional cost of service method that recognizes the role of both customer kW demand and energy in cost causation. Unlike other weighted demand and energy methodologies, the AED method gives a reasonable weighting to the importance of class demands in the allocation of the system's fixed production costs to rate classes.**

- **Though APS states that it has given some recognition to the cost of service results in its proposed rate schedule increases in this case, the Company's proposed rate spread does not reasonably reduce the current level of intra-rate class subsidies. For example, despite the fact that Rate E-32 L is currently paying rates substantially above cost of service, the Company is proposing a non-fuel, non-transmission rate increase to Rate E-32 L of 17.59%, well above the retail average increase of 11.4% ($194 million) on total revenues, less fuel and transmission revenues.**

  **A more appropriate rate spread, which I am recommending in this case, would increase all general service rate schedules by 3.73 percentage points <u>less</u> than the 11.4% retail average increase, while increasing the residential class by 3 percentage points <u>more</u> than the retail average. This rate spread more**

reasonably corresponds to the cost of service study results in this case. Table 4 provides my recommended rate spread for all classes, based on the Company's filed overall revenue increase. Assuming an overall revenue increase of 11.36% on total revenue less fuel and transmission, general service rates should be increased by 7.63% and residential class should be increased by 14.36%, on a non-fuel, non-transmission revenue basis.

- APS is proposing to eliminate the hours use rate design for Rate E-32 L (greater than 400 kW demand) and move the demand related costs currently being recovered in this hours use kWh charge into the kW demand charges of the rate. This proposal is reasonable and consistent with a cost based rate.

- APS is proposing larger increases to higher load factor E-32 L customers than to lower load factor customers. There is no evidence to support this rate design. The Company's E-32 L rate should be modified such that, after accounting for the shift of demand cost recovery from the 1st hours-use energy block to the demand charge (as proposed by APS), the restructured demand and energy charges should be increased by a uniform percentage, following the three step procedure described in my testimony.

## • II. REVENUE ALLOCATION AND COST OF SERVICE

**Q. Have you reviewed the Company's 12 month ending December 2010 test year cost of service study filed in this proceeding?**

A. Yes. The Company is utilizing a traditional Average and Excess Demand ("AED") class cost of service study in this proceeding to allocate production related demand costs. In many past cases, APS used a 4 CP allocation method because of the pronounced demands on the system during the summer months, though in the Company's 2008 case, APS adopted the AED method.[2] In the prior three APS base rate cases, I supported the Company's use of the 4 CP method and continue to do so in this case. The fact that the Company is continuing to rely on the 4 CP methodology to allocate jurisdictional costs indicates that it is an appropriate methodology for APS, given the load characteristics of the system and the significance of summer peak loads on generation costs.

**Q. Do you believe that the Company's proposal to use the AED method for retail class cost of service allocation provides a reasonable basis to evaluate the relationship between the rates being charged each rate class and the underlying cost of providing service to these customers?**

[2] APS is continuing to use a 4 CP methodology in its jurisdictional cost allocation study in this case.

A. Yes, while I would prefer the 4 CP method in this case for class cost of service, it is appropriate to use the AED method for the purpose of assessing the reasonableness of the Company's proposed allocation of the revenue increase to rate schedule. The AED method is a traditional cost of service method that recognizes the role of both customer kW demand and energy in cost causation. Unlike other weighted demand and energy methodologies, the AED method gives a reasonable weighting to the importance of class demands in the allocation of the system's fixed production costs to rate classes.

**Q. How should the results of the Company's class cost of service study be used in this case?**

A. The purpose of an embedded, fully allocated class cost of service study is to assess the reasonableness of a utility's rates, in relation to the underlying cost of providing service to the customers on each rate class. As a matter of policy, it is both efficient and equitable to establish rates on the basis of the cost of service and, to the extent feasible, to move rates towards cost of service in a rate case in which a utility is requesting a change in revenues. In other words, a rate case, such as the current APS proceeding, is an opportunity to evaluate the Company's rates and make incremental adjustments so that, over time, each class will pay rates reflecting cost of service. In so doing, rates paid by each customer will provide efficient "price signals" reflecting the resource cost of meeting customer demands. In addition, cost based rates provide an equitable basis to assign the Company's overall revenue requirement to customers. In this manner, customers in one rate class do not pay or receive unjustified monetary subsidies from other rate customers.

Q. **How do the Company's current rates compare to the underlying cost of service?**

A. A good measure of this rate versus cost relationship is the relative class rates of return at present rates. This measurement, which is the ratio of a class's rate of return relative to the average retail earned rate of return, provides a good summary of the rate versus cost relationship, based on the results of the Company's AED cost of service study.

Q. **What are the class relative rates of return results produced by the Company's test year AED cost of service study?**

A. The table below summarizes the rates of return and the relative rate of return indices ("ROR Index") for each of the major rate classes using the results of the Company's AED study.

**TABLE 1**
**Comparison of Relative Rates of Return**
**Average and Excess Demand Cost of Service Study**
**Present Rates**

| Class | Rate of Return | ROR Index |
|---|---|---|
| Residential | 6.08% | 0.73 |
| General Svc | 11.86% | 1.43 |
| E-20 (Church Rate) | 3.95% | 0.48 |
| E-32 TOU | 14.45% | 1.74 |
| E-30, E-32 (0-100 kW) | 13.25% | 1.60 |
| E-32 (101-400 kW) | 11.77% | 1.42 |
| E-32 (401+ kW) | 10.90% | 1.31 |
| E-34 | 9.41% | 1.13 |
| E-35 | 8.85% | 1.07 |
| Irrigation | 6.06% | 0.73 |
| Street Light | 7.19% | 0.87 |
| Dusk to Dawn | 9.76% | 1.18 |
| Total Retail | 8.29% | 1.00 |

Based on these results, the residential class is paying only 73% of its allocated cost of service under present rates, while general service customers are paying a relative rate of return that is approximately 143% of the system average. This is a substantial difference and one that should be addressed in this rate proceeding.

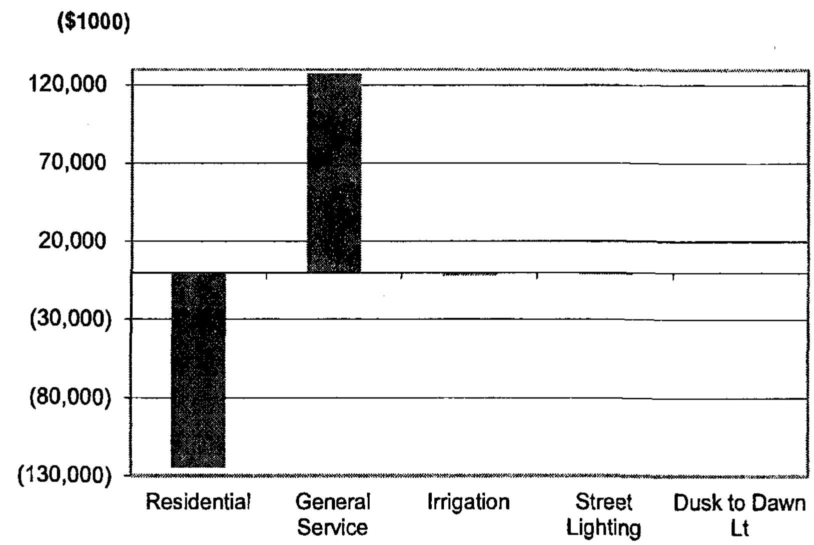
**Q. How do these relative rates of return results compare to the results in the Company's prior 2008 rate case (Docket No. E-01933A-07-0402)?**

A. In the 2008 rate case, the APS cost of service study showed that the residential class was paying only 75% of its allocated cost of service under the then existing present rates, while general service customers were paying a relative rate of return that was approximately 130% of the system average. Essentially, there was zero progress made in moving rates towards cost of service in the last rate case; in fact, general service customers now are further from cost of service than they were at the time of the last rate case.

**Q. Have you computed the dollar subsidies being paid and received by each rate class at present rates, based on the results of the 2010 Company's cost of service study filed in this case?**

A. Yes. Figure 1 below shows the dollar subsidies paid and received at present rates. As can be seen, the residential class is receiving (shown as a positive value) over $125 million in subsidies at present rate from other rate classes. At the same time, general service customers pay annual subsidies of over $125 million. These results are based on the Company's filed AED class cost of service study, without any adjustments. These subsidies have actually grown substantially since the Company's last base rate case. Baron Exhibit__(SJB-2) shows the calculation of these subsidies by rate schedule.

**Figure 1**
**Present Rate Subsidies**
**Received and (Paid)**




**Q. Has APS made rate spread proposals in this case that adequately address the substantial disparities between present rates and cost of service?**

A. Not in my opinion. APS states that it is requesting an "overall increase in retail base rates of $95,493,000, which is a 3.33% increase over adjusted test year base revenues.[3] Based on this overall increase, APS is proposing to increase residential rates by 3.95% and general service rates by 2.64%. APS witness Charles Miessner states that this rate spread is based on the results of the Company's class cost of

[3] Direct Testimony of Charles Miessner at page 3, line 23.

service study and gradualism. While I agree with the Company's principles governing its proposed rate spread (cost of service and gradualism), I disagree that the Company has reasonably applied these principles in its rate spread recommendation.

As I showed above in Table 1 and in Figure 1, the residential class is currently paying rates substantially below cost of service, while general service customers are paying rates substantially above cost. Based on this cost of service data, general service rates should receive a below average increase and residential customers should receive an above average increase in this case.

Q. **Doesn't the Company's rate spread proposal result in a lower overall increase to general service customers?**

A. No. While the Company has presented its increase in this case as a $95 million, 3.3% base rate increase, this is misleading and does not correctly portray the increases that are actually being requested by APS in this case. In addition, as I will demonstrate, when the full effect of the Company's proposed increase is properly reflected in the analysis, general service rates are actually being increased by more than the retail system average and residential rates are being increased by less than the system average.

Q. **Would you explain why the actual APS proposal in this case is a $194 million increase, rather than $95 million?**

A. While it is true that the "base rate" increase request is $95 million, APS customers currently receive a $143 million PSA credit that is being rolled in to base rates. This credit will no longer be available in the PSA, but rather included directly in base rates. The real impact on customers is thus $95 million plus $143 million. In addition, the Company is transferring $45 million into base rates from the existing REAC charge. This transfer has the opposite effect on rates from the PSA roll-in; the RES/REAC charges are reduced by $45 million and base rates are increase by $45 million. When these two transfers are netted against the $95 million reported base rate increase, the true "base rate" increase to APS retail customers is $194.093 million.

Q. **What is the impact of the actual $194 million requested increase on APS rates?**

A. Baron Exhibit__(SJB-3) shows the Company's proposed increases for each rate class and on an overall retail basis. This analysis calculates the percentage impacts on present rate revenues, excluding fuel revenues and transmission revenues.[4] Since the Company's requested increase in this case does not include fuel or transmission costs, it is appropriate to examine the APS proposal exclusive of these two revenue sources. In other words, fuel costs and transmission costs are not at issue in this

[4] The PSA and RES roll-in impacts by rate schedule have been provided by APS in response to AEEC 1.1. The base fuel amounts in present rates have been calculated using the approach used by APS in LRS_WP1.

case. Also, the class cost of service study, which APS states has been relied (together with gradualism) to apportion the overall increase to rate classes, reports class rates of return under the assumption that fuel and transmission revenues equal fuel and transmission expenses for each rate class.

The problem with the APS rate spread, which is summarized in Mr. Miessner's Schedule H-1, is that it ignores the roll-in effects of the PSA, and the REAC, and calculates the percentage increases on present revenues that include all fuel and transmission revenues, even though these costs are not affected by the proposed rate change. By failing to remove the effect of the PSA roll-in, the Company's reported rate schedule increases show a disproportionate benefit to high load factor rates that doesn't exist, because the Company fails to also include the loss of the PSA credit (it zeros out as a result of the roll-in). Since the PSA roll-in is revenue neutral on a total system basis and on a rate schedule basis, it is appropriate to remove these fuel revenues when evaluating the true impact of the Company's rate spread recommendation.

As shown in Exhibit__(SJB-3), the true overall increase requested by APS, as a percent of revenues, excluding fuel and transmission revenues, is 11.36%. This is the increase on retail revenues at issue in this case. Residential rates are being increased by 11.10% and APS is proposing that general service rates receive an 11.73% increase. However, within the general service class, a number of individual rate schedules are receiving increases substantially above the retail average. Table 2 below summarizes the Company's proposed increases by rate class, including details for general service rate schedules.

**TABLE 2**
**APS Proposed Increases**
**(% Increases on Base Revenues, Less Fuel and Transmisson)**

| Class | Proposed Increase | Proposed % Increase |
|---|---|---|
| Residential | 102,029 | 11.10% |
| General Svc | 88,421 | 11.73% |
| E-20 | 219 | 9.90% |
| E-30 | 38 | 3.33% |
| E-32 TOU | 2,837 | 16.11% |
| E-32 (0-20 kW) | 5,983 | 4.28% |
| E-32 (21-100 kW) | 9,199 | 5.11% |
| E-32 (101-400 kW) | 22,441 | 12.50% |
| E-32 (401+ kW) | 26,933 | 17.59% |
| E-34 | 8,170 | 22.72% |
| E-35 | 12,601 | 28.59% |
| Irrigation | 2,047 | 15.96% |
| Outdoor Lighting | 1,339 | 8.87% |
| Dusk to Dawn | 257 | 3.46% |
| Total Retail | 194,093 | 11.36% |

As can be seen from the table, Rate E-32 L ("401 + kW") customers will receive an increase of 17.59 under the APS proposed rate spread, compared to the average retail increase of 11.36%. This is about 150% of the average increase, despite the fact that Rate E-32 L is earning an above average rate of return (index of 1.31). There simply is no basis for the Company's proposal, which is clearly inconsistent with the stated objectives relied on by APS (cost of service, gradualism). At the same time, APS is proposing an average percentage increase to the residential class, despite the fact that residential customers are currently paying rates covering only 73% of cost of service. As I noted, the entire general service rate class is receiving a system average increase, despite the fact that present rates are substantially above cost of service.

**Q. Does the Company's proposed rate spread result in a reduction in the dollar subsidies that exist in present rates?**

A. Not in any material manner. Table 3 shows a comparison between present and proposed subsidies by rate schedule based on the Company's rate spread.

**Table 3**
**APS Present and Proposed Rate Class Subsidies**
**($1,000)**

| Class | Present Subsidy | Proposed Subsidy | Subsidy Reduction |
|---|---|---|---|
| Residential | (125,177) | (124,161) | 1.02 |
| General Service | 127,407 | 126,771 | (0.64) |
| Irrigation | (1,686) | (1,482) | 0.20 |
| Street Lighting | (1,226) | (1,590) | (0.36) |
| Dusk to Dawn Lt | 682 | 462 | (0.22) |

**Q. What conclusions have you made regarding the Company's proposed rate spread?**

A. The APS proposal is not reasonable, is inconsistent with the Company's own objectives, and will only exacerbate the existing disparities between rates and cost of service.

**Q. Have you developed an alternative rate spread recommendation that more reasonably reflects the APS cost of service results and gradualism?**

A. Yes. Baron Exhibit__(SJB-4) shows the development my recommended rate spread that reduces rate/cost disparities and reflects gradualism. Table 4 summarizes my recommendation.

**TABLE 4**
**Recommended Rate Spread**

| Class | Proposed Increase | Percent | % Deviation From Average |
|---|---|---|---|
| Residential | 132,018 | 14.36% | 3.00% |
| General Svc | 57,498 | 7.63% | -3.73% |
| Irrigation | 1,843 | 14.36% | 3.00% |
| Street Light | 2,167 | 14.36% | 3.00% |
| Dusk to Dawn | 567 | 7.63% | -3.73% |
| Total Retail | 194,093 | 11.36% | 0.00% |

**Q. Does your recommended rate spread eliminate all rate subsidies?**

A. No. I recognize that this would not be realistic, given the impact on residential customers. It would also be inconsistent with the regulatory concept of gradualism. Though this would be an ideal result and one that should be recognized as a longer-term goal in future rate proceedings, I am not recommending the elimination of all subsidies in this proceeding. However, there is no justification for increasing the disparities, given the existing situation. Some mitigation of the subsidies should be made in this case. At the same time, it is unreasonable to completely ignore the results of the Company's cost of service study.

## III. RATE E-32 L RATE DESIGN

**Q. Have you reviewed APS' proposal to redesign Rate E-32 L by eliminating the current hours-use kWh rate design and shifting demand cost recovery to the kW demand charges of the rate?**

A. Yes. I have reviewed the Company's proposal and support the revision to the E-32 L rate design. Kroger has consistently supported cost of service based rates, which will recover all demand related costs through a properly designed demand charge.

**Q. Do you have any concerns with the Company's proposed increases to the redesigned Rate E-32 L demand and energy charges?**

A. Yes. Based on my analysis, APS is proposing larger increases to higher load factor E-32 L customers than to lower load factor customers. There is no evidence to support this rate design. Baron Exhibit__(SJB-5), pages 1 and 2, show a revised typical bill analysis for Rate E-32 L that properly reflects the roll-in of the current negative PSA and the RES charge. As can be seen in this exhibit, higher load factor E-32 L customers are receiving larger percentage increases in both the winter and the summer than lower load factor customers.[5]

[5] A small number of extremely low load factor customers do receive larger increases due to the movement of demand costs from the 1st hours-use energy block to the demand charge of the rate.

**Q. How does APS' proposed E-32 L energy charge compare to the unit energy cost per kWh from the Company's cost of service study?**

A. Table 5 below shows this comparison. After removing the base fuel cost from both the unit cost rate per kWh and the proposed energy rate, the proposed non-fuel energy rate is 40% to 70% higher than cost of service. This difference cannot be justified, even considering the subsidy amount added to Rate E-32 L. Since the subsidy is effectively an additional rate of return paid built into the rate, it is reasonably related to rate base. The energy portion of E-32 L rate base is less than 1% of the overall rate base assigned to this rate schedule. Thus, even the large dollar subsidy built-in to the E-32 L rate cannot justify the excessive non-fuel energy charge proposed by APS.

**Table 5**
**Rate E-32 L Unit Energy Cost**

| | Unit Cost Data | Base Fuel | Non-Fuel Unit Cost | Percent |
|---|---|---|---|---|
| Energy Related Rev. Req. | 140,655,737 | | | |
| E-32 L kWh | 3,647,138,609 | | | |
| Unit Energy Cost | 0.038566 | 0.03242 | 0.00615 | |
| Proposed E-32 L Energy Rate | | | | |
| Summer | 0.059350 | 0.03242 | 0.02694 | |
| Winter | 0.042490 | 0.03242 | 0.01008 | |
| Excess Non-Fuel Energy Charge | | | | |
| Summer | | | 0.02078 | |
| Winter | | | 0.00392 | |
| Excess Non-Fuel Energy Charge - Percent | | | | |
| Summer | | | | 77.2% |
| Winter | | | | 38.9% |

Table 6 shows an analysis of the proposed increase in the E-32 L non-fuel energy rate. As can be seen, on a weighted average basis (summer and winter charges weighted by respective period kWh), the Company is proposing a 39% increase to this charge. Finally, the table also shows that APS' proposed non-fuel energy rate should actually be decreased on a cost of service basis by 55%.

**Table 6**
**Rate E-32 L Excess Energy Rate Analysis**

| | Present/Proposed Rates | Base Fuel | Non-Fuel Unit Cost | Percent Increase |
|---|---|---|---|---|
| Present E-32 L Energy Rate (2nd Blk) | | | | |
| Summer | 0.05902 | 0.03757 | 0.02145 | |
| Winter | 0.04239 | 0.03757 | 0.00482 | |
| Weighted Average | | | 0.01386 | |
| Proposed E-32 L Energy Rate | | | | |
| Summer | 0.059350 | 0.03242 | 0.02694 | |
| Winter | 0.042490 | 0.03242 | 0.01008 | |
| Weighted Average | | | 0.01924 | |
| APS Proposed Increase in Non-Fuel Energy Rate | | | | |
| Summer | | | 0.00549 | 25.6% |
| Winter | | | 0.00526 | 109.1% |
| Weighted Average | | | 0.00538 | 38.8% |
| Increase Supported by Unit Cost of Service (based on wtd. Avg. rates) | | | | -55.6% |

Based on these results, the Company's E-32 L rate should be modified such that, after accounting for the shift of demand cost recovery from the 1st hours-use energy block to the demand charge (as proposed by APS), the restructured demand and energy charges should be increased by a uniform percentage. To accomplish this objective, it is appropriate to use a three step process:

1. Remove demand costs from the 1st hours-use energy block of the present rate and shift these costs to the demand charge of the rate. This is a revenue neutral change.

2. Pro-form the proposed level of base fuel into the present rate, reflecting the Company's proposed roll-in of the PSA.

3. Uniformly increase both demand and energy charges (as revised in steps 1 and 2) based on the approved base rate increase in this case.

Applying this three step approach sequentially, will produce a reasonable set of increases to Rate E-32 L customers and not result in large than average increases to higher load factor E-32 L customers.

**Q. Does that complete your testimony?**

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) |
| ARIZONA PUBLIC SERVICE COMPANY FOR | ) |
| A HEARING TO DETERMINE THE FAIR VALUE | ) |
| OF THE UTILITY PROPERTY OF THE COMPANY | ) Docket No. E-01345A-11-0224 |
| FOR RATEMAKING PURPOSES, TO FIX A JUST | ) |
| AND REASONABLE RATE OF RETURN | ) |
| THEREON, TO APPROVE RATE SCHEDULES | ) |
| DESIGNED TO DEVELOP SUCH RETURN | ) |

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

# AFFIDAVIT

STATE OF GEORGIA )

COUNTY OF FULTON )

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
30th day of November 2011.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) |
| ARIZONA PUBLIC SERVICE COMPANY FOR | ) |
| A HEARING TO DETERMINE THE FAIR VALUE | ) |
| OF THE UTILITY PROPERTY OF THE COMPANY | ) Docket No. E-01345A-11-0224 |
| FOR RATEMAKING PURPOSES, TO FIX A JUST | ) |
| AND REASONABLE RATE OF RETURN | ) |
| THEREON, TO APPROVE RATE SCHEDULES | ) |
| DESIGNED TO DEVELOP SUCH RETURN | ) |

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

COST OF SERVICE/RATE DESIGN

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 4/81 | 203(B) | KY | Louisville Gas & Electric Co. | Louisville Gas & Electric Co. | Cost-of-service. |
| 4/81 | ER-81-42 | MO | Kansas City Power & Light Co. | Kansas City Power & Light Co. | Forecasting. |
| 6/81 | U-1933 | AZ | Arizona Corporation Commission | Tucson Electric Co. | Forecasting planning. |
| 2/84 | 8924 | KY | Airco Carbide | Louisville Gas & Electric Co. | Revenue requirements, cost-of-service, forecasting, weather normalization. |
| 3/84 | 84-038-U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Excess capacity, cost-of-service, rate design. |
| 5/84 | 830470-EI | FL | Florida Industrial Power Users' Group | Florida Power Corp. | Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility. |
| 10/84 | 84-199-U | AR | Arkansas Electric Energy Consumers | Arkansas Power and Light Co. | Cost allocation and rate design. |
| 11/84 | R-842651 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Interruptible rates, excess capacity, and phase-in. |
| 1/85 | 85-65 | ME | Airco Industrial Gases | Central Maine Power Co. | Interruptible rate design. |
| 2/85 | I-840381 | PA | Philadelphia Area Industrial Energy Users' Group | Philadelphia Electric Co. | Load and energy forecast. |
| 3/85 | 9243 | KY | Alcan Aluminum Corp., et al. | Louisville Gas & Electric Co. | Economics of completing fossil generating unit. |
| 3/85 | 3498-U | GA | Attorney General | Georgia Power Co. | Load and energy forecasting, generation planning economics. |
| 3/85 | R-842632 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 5/85 | 84-249 | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design return multipliers. |
| 5/85 | | City of | Chamber of | Santa Clara | Cost-of-service, rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | Santa Clara | Commerce | Municipal | |
| 6/85 | 84-768-E-42T | WV | West Virginia Industrial Intervenors | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 6/85 | E-7 Sub 391 | NC | Carolina Industrials (CIGFUR III) | Duke Power Co. | Cost-of-service, rate design, interruptible rate design. |
| 7/85 | 29046 | NY | Industrial Energy Users Association | Orange and Rockland Utilities | Cost-of-service, rate design. |
| 10/85 | 85-043-U | AR | Arkansas Gas Consumers | Arkla, Inc. | Regulatory policy, gas cost-of-service, rate design. |
| 10/85 | 85-63 | ME | Airco Industrial Gases | Central Maine Power Co. | Feasibility of interruptible rates, avoided cost. |
| 2/85 | ER-8507698 | NJ | Air Products and Chemicals | Jersey Central Power & Light Co. | Rate design. |
| 3/85 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve, prudence, off-system sales guarantee plan. |
| 2/86 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Optimal reserve margins, prudence, off-system sales guarantee plan. |
| 3/86 | 85-299U | AR | Arkansas Electric Energy Consumers | Arkansas Power & Light Co. | Cost-of-service, rate design, revenue distribution. |
| 3/86 | 85-726-EL-AIR | OH | Industrial Electric Consumers Group | Ohio Power Co. | Cost-of-service, rate design, interruptible rates. |
| 5/86 | 86-081-E-GI | WV | West Virginia Energy Users Group | Monongahela Power Co. | Generation planning economics, prudence of a pumped storage hydro unit. |
| 8/86 | E-7 Sub 408 | NC | Carolina Industrial Energy Consumers | Duke Power Co. | Cost-of-service, rate design, interruptible rates. |
| 10/86 | U-17378 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Excess capacity, economic analysis of purchased power. |
| 12/86 | 38063 | IN | Industrial Energy | Indiana & Michigan | Interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Consumers | Power Co. | |
| 3/87 | EL-86-53-001 EL-86-57-001 | Federal Energy Regulatory Commission (FERC) | Louisiana Public Service Commission Staff | Gulf States Utilities, Southern Co. | Cost/benefit analysis of unit power sales contract. |
| 4/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Load forecasting and imprudence damages, River Bend Nuclear unit. |
| 5/87 | 87-023-E-C | WV | Airco Industrial Gases | Monongahela Power Co. | Interruptible rates. |
| 5/87 | 87-072-E-G1 | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims. |
| 5/87 | 86-524-E-SC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic dispatching of pumped storage hydro unit. |
| 5/87 | 9781 | KY | Kentucky Industrial Energy Consumers | Louisville Gas & Electric Co. | Analysis of impact of 1986 Tax Reform Act. |
| 6/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning. |
| 6/87 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Phase-in plan for River Bend Nuclear unit. |
| 7/87 | 85-10-22 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Methodology for refunding rate moderation fund. |
| 8/87 | 3673-U | GA | Georgia Public Service Commission | Georgia Power Co. | Test year sales and revenue forecast. |
| 9/87 | R-850220 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Excess capacity, reliability of generating system. |
| 10/87 | R-870651 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Interruptible rate, cost-of-service, revenue allocation, rate design. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 10/87 | I-860025 | PA | Pennsylvania Industrial Intervenors | | Proposed rules for cogeneration, avoided cost, rate recovery. |
| 10/87 | E-015/ GR-87-223 | MN | Taconite Intervenors | Minnesota Power & Light Co. | Excess capacity, power and cost-of-service, rate design. |
| 10/87 | 8702-EI | FL | Occidental Chemical Corp. | Florida Power Corp. | Revenue forecasting, weather normalization. |
| 12/87 | 87-07-01 | CT | Connecticut Industrial Energy Consumers | Connecticut Light Power Co. | Excess capacity, nuclear plant phase-in. |
| 3/88 | 10064 | KY | Kentucky Industrial Energy Consumers | Louisville Gas & Electric Co. | Revenue forecast, weather normalization rate treatment of cancelled plant. |
| 3/88 | 87-183-TF | AR | Arkansas Electric Consumers | Arkansas Power & Light Co. | Standby/backup electric rates. |
| 5/88 | 870171C001 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Cogeneration deferral mechanism, modification of energy cost recovery (ECR). |
| 6/88 | 870172C005 | PA | GPU Industrial Intervenors | Pennsylvania Electric Co. | Cogeneration deferral mechanism, modification of energy cost recovery (ECR). |
| 7/88 | 88-171-EL-AIR 88-170-EL-AIR Interim Rate Case | OH | Industrial Energy Consumers | Cleveland Electric/ Toledo Edison | Financial analysis/need for interim rate relief. |
| 7/88 | Appeal of PSC | 19th Judicial Docket U-17282 | Louisiana Public Service Commission Circuit Court of Louisiana | Gulf States Utilities | Load forecasting, imprudence damages. |
| 11/88 | R-880989 | PA | United States Steel | Carnegie Gas | Gas cost-of-service, rate design. |
| 11/88 | 88-171-EL-AIR 88-170-EL-AIR | OH | Industrial Energy Consumers | Cleveland Electric/ Toledo Edison. General Rate Case. | Weather normalization of peak loads, excess capacity, regulatory policy. |
| 3/89 | 870216/283 284/286 | PA | Armco Advanced Materials Corp., | West Penn Power Co. | Calculated avoided capacity, recovery of capacity payments. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | Allegheny Ludlum Corp. | | |
| 8/89 | 8555 | TX | Occidental Chemical Corp. | Houston Lighting & Power Co. | Cost-of-service, rate design. |
| 8/89 | 3840-U | GA | Georgia Public Service Commission | Georgia Power Co. | Revenue forecasting, weather normalization. |
| 9/89 | 2087 | NM | Attorney General of New Mexico | Public Service Co. of New Mexico | Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting. |
| 10/89 | 2262 | NM | New Mexico Industrial Energy Consumers | Public Service Co. of New Mexico | Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost. |
| 11/89 | 38728 | IN | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates. |
| 1/90 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Jurisdictional cost allocation, O&M expense analysis. |
| 5/90 | 890366 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Non-utility generator cost recovery. |
| 6/90 | R-901609 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Allocation of QF demand charges in the fuel cost, cost-of-service, rate design. |
| 9/90 | 8278 | MD | Maryland Industrial Group | Baltimore Gas & Electric Co. | Cost-of-service, rate design, revenue allocation. |
| 12/90 | U-9346 Rebuttal | MI | Association of Businesses Advocating Tariff Equity | Consumers Power Co. | Demand-side management, environmental externalities. |
| 12/90 | U-17282 Phase IV | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Revenue requirements, jurisdictional allocation. |
| 12/90 | 90-205 | ME | Airco Industrial Gases | Central Maine Power Co. | Investigation into interruptible service and rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 1/91 | 90-12-03 Interim | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Interim rate relief, financial analysis, class revenue allocation. |
| 5/91 | 90-12-03 Phase II | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Revenue requirements, cost-of-service, rate design, demand-side management. |
| 8/91 | E-7, SUB SUB 487 | NC | North Carolina Industrial Energy Consumers | Duke Power Co. | Revenue requirements, cost allocation, rate design, demand-side management. |
| 8/91 | 8341 Phase I | MD | Westvaco Corp. | Potomac Edison Co. | Cost allocation, rate design, 1990 Clean Air Act Amendments. |
| 8/91 | 91-372 EL-UNC | OH | Armco Steel Co., L.P. | Cincinnati Gas & Electric Co. | Economic analysis of cogeneration, avoid cost rate. |
| 9/91 | P-910511 P-910512 | PA | Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group | West Penn Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 9/91 | 91-231 -E-NC | WV | West Virginia Energy Users' Group | Monongahela Power Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 | 8341 - Phase II | MD | Westvaco Corp. | Potomac Edison Co. | Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures. |
| 10/91 | U-17282 | LA | Louisiana Public Service Commission Staff | Gulf States Utilities | Results of comprehensive management audit. |
| Note: No testimony was prefiled on this. | | | | | |
| 11/91 | U-17949 Subdocket A | LA | Louisiana Public Service Commission Staff | South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co. | Analysis of South Central Bell's restructuring and |
| 12/91 | 91-410-EL-AIR | OH | Armco Steel Co., Air Products & Chemicals, Inc. | Cincinnati Gas & Electric Co. | Rate design, interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 12/91 | P-880286 | PA | Armco Advanced Materials Corp., Allegheny Ludlum Corp. | West Penn Power Co. | Evaluation of appropriate avoided capacity costs - QF projects. |
| 1/92 | C-913424 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Industrial interruptible rate. |
| 6/92 | 92-02-19 | CT | Connecticut Industrial Energy Consumers | Yankee Gas Co. | Rate design. |
| 8/92 | 2437 | NM | New Mexico Industrial Intervenors | Public Service Co. of New Mexico | Cost-of-service. |
| 8/92 | R-00922314 | PA | GPU Industrial Intervenors | Metropolitan Edison Co. | Cost-of-service, rate design, energy cost rate. |
| 9/92 | 39314 | ID | Industrial Consumers for Fair Utility Rates | Indiana Michigan Power Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 10/92 | M-00920312 C-007 | PA | The GPU Industrial Intervenors | Pennsylvania Electric Co. | Cost-of-service, rate design, energy cost rate, rate treatment. |
| 12/92 | U-17949 | LA | Louisiana Public Service Commission Staff | South Central Bell Co. | Management audit. |
| 12/92 | R-00922378 | PA | Armco Advanced Materials Co. The WPP Industrial Intervenors | West Penn Power Co. | Cost-of-service, rate design, energy cost rate, $SO_2$ allowance rate treatment. |
| 1/93 | 8487 | MD | The Maryland Industrial Group | Baltimore Gas & Electric Co. | Electric cost-of-service and rate design, gas rate design (flexible rates). |
| 2/93 | E002/GR-92-1185 | MN | North Star Steel Co. Praxair, Inc. | Northern States Power Co. | Interruptible rates. |
| 4/93 | EC92 21000 ER92-806-000 (Rebuttal) | Federal Energy Regulatory Commission | Louisiana Public Service Commission Staff | Gulf States Utilities/Entergy agreement. | Merger of GSU into Entergy System; impact on system |
| 7/93 | 93-0114-E-C | WV | *Airco Gases* | Monongahela Power Co. | Interruptible rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 8/93 | 930759-EG | FL | Florida Industrial Power Users' Group | Generic - Electric Utilities | Cost recovery and allocation of DSM costs. |
| 9/93 | M-009 30406 | PA | Lehigh Valley Power Committee | Pennsylvania Power & Light Co. | Ratemaking treatment of off-system sales revenues. |
| 11/93 | 346 | KY | Kentucky Industrial Utility Customers | Generic - Gas Utilities | Allocation of gas pipeline transition costs - FERC Order 636. |
| 12/93 | U-17735 | LA | Louisiana Public Service Commission Staff | Cajun Electric Power Cooperative | Nuclear plant prudence, forecasting, excess capacity. |
| 4/94 | E-015/ GR-94-001 | MN | Large Power Intervenors | Minnesota Power Co. | Cost allocation, rate design, rate phase-in plan. |
| 5/94 | U-20178 | LA | Louisiana Public Service Commission | Louisiana Power & Light Co. | Analysis of least cost integrated resource plan and demand-side management program. |
| 7/94 | R-00942986 | PA | Armco, Inc.; West Penn Power Industrial Intervenors | West Penn Power Co. | Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense. |
| 7/94 | 94-0035-E-42T | WV | West Virginia Energy Users Group | Monongahela Power Co. | Cost-of-service, allocation of rate increase, and rate design. |
| 8/94 | EC94 13-000 | Federal Energy Regulatory Commission | Louisiana Public Service Commission | Gulf States Utilities/Entergy | Analysis of extended reserve shutdown units and violation of system agreement by Entergy. |
| 9/94 | R-00943 081 R-00943 081C0001 | PA | Lehigh Valley Power Committee | Pennsylvania Public Utility Commission | Analysis of interruptible rate terms and conditions, availability. |
| 9/94 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Evaluation of appropriate avoided cost rate. |
| 9/94 | U-19904 | LA | Louisiana Public Service Commission | Gulf States Utilities | Revenue requirements. |
| 10/94 | 5258-U | GA | Georgia Public Service Commission | Southern Bell Telephone & Telegraph Co. | Proposals to address competition in telecommunication markets. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 11/94 | EC94-7-000 ER94-898-000 | FERC | Louisiana Public Service Commission | El Paso Electric and Central and Southwest | Merger economics, transmission equalization hold harmless proposals. |
| 2/95 | 941-430EG | CO | CF&I Steel, L.P. | Public Service Company of Colorado | Interruptible rates, cost-of-service. |
| 4/95 | R-00943271 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Cost-of-service, allocation of rate increase, rate design, interruptible rates. |
| 6/95 | C-00913424 C-00946104 | PA | Duquesne Interruptible Complainants | Duquesne Light Co. | Interruptible rates. |
| 8/95 | ER95-112 -000 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. | Open Access Transmission Tariffs - Wholesale. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Company | Nuclear decommissioning, revenue requirements, capital structure. |
| 10/95 | ER95-1042 -000 | FERC | Louisiana Public Service Commission | System Energy Resources, Inc. | Nuclear decommissioning, revenue requirements. |
| 10/95 | U-21485 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Nuclear decommissioning and cost of debt capital, capital structure. |
| 11/95 | I-940032 | PA | Industrial Energy Consumers of Pennsylvania | State-wide - all utilities | Retail competition issues. |
| 7/96 | U-21496 | LA | Louisiana Public Service Commission | Central Louisiana Electric Co. | Revenue requirement analysis. |
| 7/96 | 8725 | MD | Maryland Industrial Group | Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co. | Ratemaking issues associated with a Merger. |
| 8/96 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Revenue requirements. |
| 9/96 | U-22092 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 2/97 | R-973877 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Competitive restructuring policy issues, stranded cost, transition charges. |
| 6/97 | Civil Action No. 94-11474 | US Bank-ruptcy Court Middle District of Louisiana | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Confirmation of reorganization plan; analysis of rate paths produced by competing plans. |
| 6/97 | R-973953 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 6/97 | 8738 | MD | Maryland Industrial Group | Generic | Retail competition issues |
| 7/97 | R-973954 | PA | PP&L Industrial Customer Alliance | Pennsylvania Power & Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | 97-204 | KY | Alcan Aluminum Corp. Southwire Co. | Big River Electric Corp. | Analysis of cost of service issues - Big Rivers Restructuring Plan |
| 10/97 | R-974008 | PA | Metropolitan Edison Industrial Users | Metropolitan Edison Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 10/97 | R-974009 | PA | Pennsylvania Electric Industrial Customer | Pennsylvania Electric Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 11/97 | U-22491 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Decommissioning, weather normalization, capital structure. |
| 11/97 | P-971265 | PA | Philadelphia Area Industrial Energy Users Group | Enron Energy Services Power, Inc./ PECO Energy | Analysis of Retail Restructuring Proposal. |
| 12/97 | R-973981 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 12/97 | R-974104 | PA | Duquesne Industrial Intervenors | Duquesne Light Co. | Retail competition issues, rate unbundling, stranded cost analysis. |
| 3/98 (Allocated Stranded Cost Issues) | U-22092 | LA | Louisiana Public Service Commission | Gulf States Utilities Co. | Retail competition, stranded cost quantification. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 3/98 | U-22092 | | Louisiana Public Service Commission | Gulf States Utilities, Inc. | Stranded cost quantification, restructuring issues. |
| 9/98 | U-17735 | | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Revenue requirements analysis, weather normalization. |
| 12/98 | 8794 | MD | Maryland Industrial Group and Millennium Inorganic Chemicals Inc. | Baltimore Gas and Electric Co. | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 12/98 | U-23358 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 5/99 (Cross-Answering Testimony) | EC-98-40-000 | FERC | Louisiana Public Service Commission | American Electric Power Co. & Central South West Corp. | Merger issues related to market power mitigation proposals. |
| 5/99 (Response Testimony) | 98-426 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. | Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services. |
| 6/99 | 98-0452 | WV | West Virginia Energy Users Group | Appalachian Power, Monongahela Power, & Potomac Edison Companies | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | 99-03-35 | CT | Connecticut Industrial \Energy Consumers | United Illuminating Company | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 7/99 | Adversary Proceeding No. 98-1065 | U.S. Bankruptcy Court | Louisiana Public Service Commission | Cajun Electric Power Cooperative | Motion to dissolve preliminary injunction. |
| 7/99 | 99-03-06 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power Co. | Electric utility restructuring, stranded cost recovery, rate unbundling. |
| 10/99 | U-24182 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, weather normalization, Entergy System Agreement. |
| 12/99 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Ananlysi of Proposed Contract Rates, Market Rates. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 03/00 | U-17735 | LA | Louisiana Public Service Commission | Cajun Electric Power Cooperative, Inc. | Evaluation of Cooperative Power Contract Elections |
| 03/00 | 99-1658-EL-ETP | OH | AK Steel Corporation | Cincinnati Gas & Electric Co. | Electric utility restructuring, stranded cost recovery, rate Unbundling. |
| 08/00 | 98-0452 E-GI | WVA | West Virginia Energy Users Group | Appalachian Power Co. American Electric Co. | Electric utility restructuring rate unbundling. |
| 08/00 | 00-1050 E-T 00-1051-E-T | WVA | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Electric utility restructuring rate unbundling. |
| 10/00 | SOAH 473-00-1020 PUC 2234 | TX | The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities | TXU, Inc. | Electric utility restructuring rate unbundling. |
| 12/00 | U-24993 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning, revenue requirements. |
| 12/00 | EL00-66-000 & ER00-2854 EL95-33-002 | LA | Louisiana Public Service Commission | Entergy Services Inc. | Inter-Company System Agreement: Modifications for retail competition, interruptible load. |
| 04/01 | U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Jurisdictional Business Separation - Texas Restructuring Plan |
| 10/01 | 14000-U | GA | Georgia Public Service Commission Adversary Staff | Georgia Power Co. | Test year revenue forecast. |
| 11/01 | U-25687 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Nuclear decommissioning requirements transmission revenues. |
| 11/01 | U-25965 | LA | Louisiana Public Service Commission | Generic | Independent Transmission Company ("Transco"). RTO rate design. |
| 03/02 | 001148-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design, resource planning and demand side management. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 06/02 | U-25965 | LA | Louisiana Public Service Commission | Entergy Gulf States Entergy Louisiana | RTO Issues |
| 07/02 | U-21453 | LA | Louisiana Public Service Commission | SWEPCO, AEP | Jurisdictional Business Sep. - Texas Restructuring Plan. |
| 08/02 | U-25888 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. Entergy Gulf States, Inc. | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 08/02 | EL01-88-000 | FERC | Louisiana Public Service Commission | Entergy Services Inc. and the Entergy Operating Companies | Modifications to the Inter-Company System Agreement, Production Cost Equalization. |
| 11/02 | 02S-315EG | CO | CF&I Steel & Climax Molybdenum Co. | Public Service Co. of Colorado | Fuel Adjustment Clause |
| 01/03 | U-17735 | LA | Louisiana Public Service Commission | Louisiana Coops | Contract Issues |
| 02/03 | 02S-594E | CO | Cripple Creek and Victor Gold Mining Co. | Aquila, Inc. | Revenue requirements, purchased power. |
| 04/03 | U-26527 | LA | Louisiana Public Service Commission | Entergy Gulf States, Inc. | Weather normalization, power purchase expenses, System Agreement expenses. |
| 11/03 | ER03-753-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Tariff MSS-4. |
| 11/03 | ER03-583-000 ER03-583-001 ER03-583-002<br>ER03-681-000, ER03-681-001<br>ER03-682-000, ER03-682-001 ER03-682-002 | FERC | Louisiana Public Service Commission | Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 12/03 | U-27136 | LA | Louisiana Public Service Commission | Entergy Louisiana, Inc. | Evaluation of Wholesale Purchased Power Contracts. |
| 01/04 | E-01345-03-0437 | AZ | Kroger Company | Arizona Public Service Co. | Revenue allocation rate design. |
| 02/04 | 00032071 | PA | Duquesne Industrial Intervenors | Duquesne Light Company | Provider of last resort issues. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 03/04 | 03A-436E | CO | CF&I Steel, LP and Climax Molybedenum | Public Service Company of Colorado | Purchased Power Adjustment Clause. |
| 04/04 | 2003-00433 2003-00434 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service Rate Design |
| 0-6/04 | 03S-539E | CO | Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co. | Aquila, Inc. | Cost of Service, Rate Design Interruptible Rates |
| 06/04 | R-00049255 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 10/04 | 04S-164E | CO | CF&I Steel Company, Climax Mines | Public Service Company of Colorado | Cost of service, rate design, Interruptible Rates. |
| 03/05 | Case No. 2004-00426 Case No. 2004-00421 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities Louisville Gas & Electric Co. | Environmental cost recovery. |
| 06/05 | 050045-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design |
| 07/05 | U-28155 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc. Entergy Gulf States, Inc. | Independent Coordinator of Transmission – Cost/Benefit |
| 09/05 | Case Nos. 05-0402-E-CN 05-0750-E-PC | WVA | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Environmental cost recovery, Securitization, Financing Order |
| 01/06 | 2005-00341 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Power Company | Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism |
| 03/06 | U-22092 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |
| 04/06 | U-25116 | LA | Louisiana Public Service Commission Staff | Entergy Louisiana, Inc. | Transmission Prudence Investigation |
| 06/06 | R-00061346 C0001-0005 | PA | Duquesne Industrial Intervenors & IECPA | Duquesne Light Co. | Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues |
| 06/06 | R-00061366 R-00061367 P-00062213 | | Met-Ed Industrial Energy Users Group and Penelec Industrial Customer | Metropolitan Edison Co. Pennsylvania Electric Co. | Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | P-00062214 | | Alliance | | |
| 07/06 | U-22092 Sub-J | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. | Separation of EGSI into Texas and Louisiana Companies. |
| 07/06 | Case No. 2006-00130 Case No. 2006-00129 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Utilities Louisville Gas & Electric Co. | Environmental cost recovery. |
| 08/06 | Case No. PUE-2006-00065 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment |
| 09/06 | E-01345A-05-0816 | AZ | Kroger Company | Arizona Public Service Co. | Revenue allocation, cost of service, rate design. |
| 11/06 | Doc. No. 97-01-15RE02 | CT | Connecticut Industrial Energy Consumers | Connecticut Light & Power United Illuminating | Rate unbundling issues. |
| 01/07 | Case No. 06-0960-E-42T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Retail Cost of Service Revenue apportionment |
| 03/07 | U-29764 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. Entergy Louisiana, LLC | Implementation of FERC Decision Jurisdictional & Rate Class Allocation |
| 05/07 | Case No. 07-63-EL-UNC | OH | Ohio Energy Group | Ohio Power, Columbus Southern Power | Environmental Surcharge Rate Design |
| 05/07 | R-00049255 Remand | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues and transmission service charge. |
| 06/07 | R-00072155 | PA | PP&L Industrial Customer Alliance PPLICA | PPL Electric Utilities Corp. | Cost of service, rate design, tariff issues. |
| 07/07 | Doc. No. 07F-037E | CO | Gateway Canyons LLC | Grand Valley Power Coop. | Distribution Line Cost Allocation |
| 09/07 | Doc. No. 05-UR-103 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Electric Power Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 11/07 | ER07-682-000 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues. |
| 1/08 | Doc. No. 20000-277-ER-07 | WY | Cimarex Energy Company | Rocky Mountain Power (PacifiCorp) | Vintage Pricing, Marginal Cost Pricing Projected Test Year |
| 1/08 | Case No. 07-551 | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| | | | | | Rate Schedules |
| 2/08 | ER07-956 | FERC | Louisiana Public Service Commission Staff | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 2/08 | Doc No. P-00072342 | PA | West Penn Power Industrial Intervenors | West Penn Power Co. | Default Service Plan issues. |
| 3/08 | Doc No. E-01933A-05-0650 | AZ | Kroger Company | Tucson Electric Power Co. | Cost of Service, Rate Design |
| 05/08 | 08-0278 E-GI | WV | West Virginia Energy Users Group | Appalachian Power Co. American Electric Power Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 6/08 | Case No. 08-124-EL-ATA | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Recovery of Deferred Fuel Cost |
| 7/08 | Docket No. 07-035-93 | UT | Kroger Company | Rocky Mountain Power Co. | Cost of Service, Rate Design |
| 08/08 | Doc. No. 6680-UR-116 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Power and Light Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 09/08 | Doc. No. 6690-UR-119 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Public Service Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 09/08 | Case No. 08-936-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Competitive Solicitation |
| 09/08 | Case No. 08-935-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Rate Plan |
| 09/08 | Case No. 08-917-EL-SSO 08-918-EL-SSO | OH | Ohio Energy Group | Ohio Power Company Columbus Southern Power Co. | Provider of Last Resort Rate Plan |
| 10/08 | 2008-00251 2008-00252 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service, Rate Design |
| 11/08 | 08-1511 E-GI | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 11/08 | M-2008-2036188, M-2008-2036197 | PA | Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance | Metropolitan Edison Co. Pennsylvania Electric Co. | Transmission Service Charge |
| 01/09 | ER08-1056 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 01/09 | E-01345A-08-0172 | AZ | Kroger Company | Arizona Public Service Co. | Cost of Service, Rate Design |
| 02/09 | 2008-00409 | KY | Kentucky Industrial Utility Customers, Inc. | East Kentucky Power Cooperative, Inc. | Cost of Service, Rate Design |
| 5/09 | PUE-2009 -00018 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Transmission Cost Recovery Rider |
| 5/09 | 09-0177-E-GI | WV | West Virginia Energy Users Group | Appalachian Power Company | Expanded Net Energy Cost "ENEC" Analysis |
| 6/09 | PUE-2009 -00016 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Fuel Cost Recovery Rider |
| 6/09 | PUE-2009 -00038 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Company | Fuel Cost Recovery Rider |
| 7/09 | 080677-EI | FL | South Florida Hospital and Healthcare Assoc. | Florida Power & Light Company | Retail cost of service, rate design |
| 8/09 | U-20925 (RRF 2004) | LA | Louisiana Public Service Commission Staff | Entergy Louisiana LLC | Interruptible Rate Refund Settlement |
| 9/09 | 09AL-299E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Energy Cost Rate issues |
| 9/09 | Doc. No. 05-UR-104 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Electric Power Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 9/09 | Doc. No. 6680-UR-117 | WI | Wisconsin Industrial Energy Group, Inc. | Wisconsin Power and Light Co. | Cost of Service, rate design, tariff Issues, Interruptible rates. |
| 10/09 | Docket No. 09-035-23 | UT | Kroger Company | Rocky Mountain Power Co. | Cost of Service, Allocation of Rev Increase |
| 10/09 | 09AL-299E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Cost of Service, Rate Design |
| 11/09 | PUE-2009 -00019 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Cost of Service, Rate Design |
| 11/09 | 09-1485 E-P | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |
| 12/09 | Case No. 09-906-EL-SSO | OH | Ohio Energy Group | Ohio Edison, Toledo Edison Cleveland Electric Illuminating | Provider of Last Resort Rate Plan |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 12/09 | ER09-1224 | FERC | Louisiana Public Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | Entergy's Compliance Filing System Agreement Bandwidth Calculations. |
| 12/09 | Case No. PUE-2009-00030 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Allocation of Rev Increase, Rate Design |
| 2/10 | Docket No. 09-035-23 | UT | Kroger Company | Rocky Mountain Power Co. | Rate Design |
| 3/10 | Case No. 09-1352-E-42T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Retail Cost of Service Revenue apportionment |
| 3/10 | E015/ GR-09-1151 | MN | Large Power Intervenors | Minnesota Power Co. | Cost of Service, rate design |
| 4/10 | EL09-61 | FERC | Louisiana Public Service Service Commission | Entergy Services, Inc. and the Entergy Operating Companies | System Agreement Issues Related to off-system sales |
| 4/10 | 2009-00459 | KY | Kentucky Industrial Utility Customers, Inc. | Kentucky Power Company | Cost of service, rate design, transmission expenses. |
| 4/10 | 2009-00548 2009-00549 | KY | Kentucky Industrial Utility Customers, Inc. | Louisville Gas & Electric Co. Kentucky Utilities Co. | Cost of Service, Rate Design |
| 7/10 | R-2010-2161575 | PA | Philadelphia Area Industrial Energy Users Group | PECO Energy Company | Cost of Service, Rate Design |
| 09/10 | 2010-00167 | KY | Kentucky Industrial Utility Customers, Inc. | East Kentucky Power Cooperative, Inc. | Cost of Service, Rate Design |
| 09/10 | 10M-245E | CO | CF&I Steel Company Climax Molybdenum | Public Service Company of Colorado | Economic Impact of Clean Air Act |
| 11/10 | 10-0699-E-42T | WV | West Virginia Energy Users Group | Appalachian Power Company | Cost of Service, Rate Design, Transmission Rider |
| 11/10 | Doc. No. 4220-UR-116 | WI | Wisconsin Industrial Energy Group, Inc. | Northern States Power Co. Wisconsin | Cost of Service, rate design |
| 12/10 | 10A-554EG | CO | CF&I Steel Company Climax Molybdenum | Public Service Company | Demand Side Management Issues |
| 12/10 | 10-2586-EL-SSO | OH | Ohio Energy Group | Duke Energy Ohio | Provider of Last Resort Rate Plan Electric Security Plan |

**Expert Testimony Appearances**
**of**
**Stephen J. Baron**
**As of November 2011**

| Date | Case | Jurisdict. | Party | Utility | Subject |
|---|---|---|---|---|---|
| 3/11 | 20000-384-ER-10 | WY | Wyoming Industrial Energy Consumers | Rocky Mountain Power Wyoming | Electric Cost of Service, Revenue Apportionment, Rate Design |
| 6/11 | Docket No. 10-035-124 | UT | Kroger Company | Rocky Mountain Power Co. | Class Cost of Service |
| 6/11 | PUE-2011 -00045 | VA | VA Committee For Fair Utility Rates | Dominion Virginia Power Company | Fuel Cost Recovery Rider |
| 07/11 | U-29764 | LA | Louisiana Public Service Commission Staff | Entergy Gulf States, Inc. Entergy Louisiana, LLC | Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues |
| 07/11 | Case Nos. 11-346-EL-SSO 11-348-EL-SSO | OH | Ohio Energy Group | Ohio Power Company Columbus Southern Power Co. | Electric Security Rate Plan, Provider of Last Resort Issues |
| 08/11 | PUE-2011-00034 | VA | Old Dominion Committee For Fair Utility Rates | Appalachian Power Co. | Cost Allocation, Rate Recovery of RPS Costs |
| 09/11 | 2011-00161 2011-00162 | KY | Kentucky Industrial Utility | Louisville Gas & Electric Co. Kentucky Utilities Company | Environmental Cost Recovery |
| 09/11 | Case Nos. 11-346-EL-SSO 11-348-EL-SSO | OH | Ohio Energy Group | Ohio Power Company Columbus Southern Power Co. | Electric Security Rate Plan, Stipulation Support Testimony |
| 10/11 | 11-0452 E-P-T | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Energy Efficiency/Demand Reduction Cost Recovery |
| 11/11 | 11-1274 E-P | WV | West Virginia Energy Users Group | Mon Power Co. Potomac Edison Co. | Expanded Net Energy Cost "ENEC" Analysis. |

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) |
| ARIZONA PUBLIC SERVICE COMPANY FOR | ) |
| A HEARING TO DETERMINE THE FAIR VALUE | ) |
| OF THE UTILITY PROPERTY OF THE COMPANY | ) Docket No. E-01345A-11-0224 |
| FOR RATEMAKING PURPOSES, TO FIX A JUST | ) |
| AND REASONABLE RATE OF RETURN | ) |
| THEREON, TO APPROVE RATE SCHEDULES | ) |
| DESIGNED TO DEVELOP SUCH RETURN | ) |

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

COST OF SERVICE/RATE DESIGN

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

**ARIZONA PUBLIC SERVICE COMPANY**
**CALCULATION OF SUBSIDIES UNDER PRESENT AND PROPOSED RATES**
TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED

| | ACC JURISDICTION | | | | | |
|---|---|---|---|---|---|---|
| | TOTAL RETAIL (5) | RESIDENTIAL (6) | GENERAL SERVICE (7) | E-221 (Water Pumping) (8) | STREET LIGHTING (9) | DUSK TO DAWN (10) |
| Adjusted Rate Revenue *per APS* | 2,868,857,719 | 1,470,133,377 | 1,342,600,008 | 26,669,231 | 20,998,548 | 8,456,555 |
| Other Revenue | 121,013,337 | 61,674,921 | 56,525,049 | 1,216,323 | 1,167,525 | 429,518 |
| Total Adjusted Revenue | 2,989,871,056 | 1,531,808,298 | 1,399,125,057 | 27,885,554 | 22,166,073 | 8,886,073 |
| Total Operating Expenses | 2,515,515,172 | 1,323,943,907 | 1,142,987,717 | 25,119,326 | 17,323,570 | 6,140,652 |
| Adjusted Operating Income | 474,355,885 | 207,864,392 | 256,137,340 | 2,766,228 | 4,842,504 | 2,745,421 |
| Adjusted Rate Base | 5,720,277,476 | 3,419,731,076 | 2,159,417,218 | 45,658,280 | 67,341,332 | 28,129,571 |
| Rate of Return at Present Rates | 8.29% | 6.08% | 11.86% | 6.06% | 7.19% | 9.76% |
| Relative Rate of Return | 1.00 | 0.73 | 1.43 | 0.73 | 0.87 | 1.18 |
| Subsdidy at Present ROR | (0) | (125,176,880) | 127,407,098 | (1,686,263) | (1,226,341) | 682,386 |
| Requested ROR - Original Cost | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% |
| Required Revenue Increase to Req ROR | 54,609,705 | 157,823,986 | (106,791,815) | 2,122,148 | 1,869,228 | (413,842) |
| APS Requested Fair Value Increment | 40,883,000 | 24,440,924 | 15,433,422 | 326,321 | 481,291 | 201,043 |
| Total Increase Requested - Equal ROR | 95,492,705 | 182,264,910 | (91,358,393) | 2,448,469 | 2,350,518 | (212,799) |
| APS Proposed Increases | 95,493,000 | 58,104,000 | 35,413,000 | 966,000 | 761,000 | 249,000 |
| Tax on Proposed Increase | (37,729,284) | (22,956,890) | (13,991,676) | (381,667) | (300,671) | (98,380) |
| Operating Income at Proposed Rates | 532,119,601 | 243,011,501 | 277,558,664 | 3,350,562 | 5,302,833 | 2,896,041 |
| Rate of Return at Proposed Rates | 9.30% | 7.11% | 12.85% | 7.34% | 7.87% | 10.30% |
| Relative Rate of Return | 1.00 | 0.76 | 1.38 | 0.79 | 0.85 | 1.11 |
| Subsidy at Proposed ROR | (0) | (124,161,065) | 126,771,269 | (1,482,468) | (1,589,529) | 461,793 |

**ARIZONA PUBLIC SERVICE COMPANY**
**CALCULATION OF SUBSIDIES UNDER PRESENT AND PROPOSED RATES**
TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED

| | GENERAL SERVICE RATE SCHEDULES | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | TOTAL GENERAL SVC (12) | E-20 (Church Rate) (13) | E-32 TOU (0-100kW) (14) | E-32 TOU (101-400kW) (15) | E-32 TOU (401+ kW) (16) | E-30, E-32 (0 - 100 kW) (17) | E-32 (101 - 400 kW) (18) | E-32 (401+ kW) (19) | E-34 (20) | E-35 (21) |
| Adjusted Rate Revenue per APS | 1,342,600,008 | 3,885,908 | 5,087,112 | 6,385,132 | 22,916,517 | 490,605,200 | 317,315,278 | 303,798,301 | 80,597,093 | 112,009,467 |
| Other Revenue | 56,525,049 | 165,168 | 179,003 | 267,333 | 1,120,199 | 17,230,008 | 13,386,728 | 13,992,412 | 4,122,181 | 6,062,018 |
| Total Adjusted Revenue | 1,399,125,057 | 4,051,076 | 5,266,115 | 6,652,465 | 24,036,716 | 507,835,208 | 330,702,006 | 317,790,713 | 84,719,274 | 118,071,485 |
| Total Operating Expenses | 1,142,987,717 | 3,624,832 | 3,894,824 | 5,243,470 | 20,317,695 | 394,821,973 | 269,399,544 | 266,433,886 | 73,645,452 | 105,606,042 |
| Adjusted Operating Income | 256,137,340 | 426,244 | 1,371,291 | 1,408,995 | 3,719,021 | 113,013,235 | 61,302,461 | 51,356,827 | 11,073,822 | 12,465,443 |
| Adjusted Rate Base | 2,159,417,218 | 10,796,550 | 5,439,067 | 7,934,303 | 31,602,764 | 852,780,613 | 521,011,457 | 471,197,520 | 117,735,373 | 140,919,571 |
| Rate of Return at Present Rates | 11.86% | 3.95% | 25.21% | 17.76% | 11.77% | 13.25% | 11.77% | 10.90% | 9.41% | 8.85% |
| Relative Rate of Return | 1.43 | 0.48 | 3.04 | 2.14 | 1.42 | 1.60 | 1.42 | 1.31 | 1.13 | 1.07 |
| Subsidy at Present ROR | 127,407,098 | (775,455) | 1,521,365 | 1,241,620 | 1,815,795 | 69,923,950 | 29,918,647 | 20,305,625 | 2,166,647 | 1,288,903 |
| Requested ROR - Original Cost | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% | 8.87% |
| Required Revenue Increase to Req ROR | (106,791,815) | 878,527 | (1,469,440) | (1,165,874) | (1,514,093) | (61,782,720) | (24,944,713) | (15,807,249) | (1,042,664) | 56,412 |
| APS Requested Fair Value Increment | 15,433,422 | 77,163 | 38,873 | 56,707 | 225,866 | 6,094,849 | 3,723,685 | 3,367,663 | 841,458 | 1,007,157 |
| Total Increase Requested - Equal ROR | (91,358,393) | 955,690 | (1,430,567) | (1,109,167) | (1,288,227) | (55,687,870) | (21,221,028) | (12,439,586) | (201,206) | 1,063,569 |
| APS Proposed Increases | 35,413,000 | 151,000 | 101,000 | 158,000 | 635,000 | 10,911,000 | 8,791,000 | 8,418,000 | 2,476,000 | 3,772,000 |
| Tax on Proposed Increase | (13,991,676) | (59,660) | (39,905) | (62,426) | (250,889) | (4,310,936) | (3,473,324) | (3,325,952) | (978,268) | (1,490,317) |
| Operating Income at Proposed Rates | 277,558,664 | 517,584 | 1,432,386 | 1,504,569 | 4,103,133 | 119,613,298 | 66,620,137 | 56,448,876 | 12,571,555 | 14,747,126 |
| Rate of Return at Proposed Rates | 12.85% | 4.79% | 26.34% | 18.96% | 12.98% | 14.03% | 12.79% | 11.98% | 10.68% | 10.46% |
| Relative Rate of Return | 1.38 | 0.52 | 2.83 | 2.04 | 1.40 | 1.51 | 1.37 | 1.29 | 1.15 | 1.12 |
| Subsidy at Proposed ROR | 126,771,269 | (804,691) | 1,531,567 | 1,267,167 | 1,923,228 | 66,598,757 | 30,012,003 | 20,857,573 | 2,677,211 | 2,708,453 |

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) |
| ARIZONA PUBLIC SERVICE COMPANY FOR | ) |
| A HEARING TO DETERMINE THE FAIR VALUE | ) |
| OF THE UTILITY PROPERTY OF THE COMPANY | ) Docket No. E-01345A-11-0224 |
| FOR RATEMAKING PURPOSES, TO FIX A JUST | ) |
| AND REASONABLE RATE OF RETURN | ) |
| THEREON, TO APPROVE RATE SCHEDULES | ) |
| DESIGNED TO DEVELOP SUCH RETURN | ) |

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

COST OF SERVICE/RATE DESIGN

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

# ARIZONA PUBLIC SERVICE COMPANY
## ANALYSIS OF BASE REVENUES BY DETAILED CLASS
## TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED

*Revenues without Fuel and Transmission*

| Line No. | Customer Classification and Current Rate Designation | Base Revenues under Present Rates[1] ($000) | 0.037571 Less: Base Fuel | Less: Transmission | Total Revenues Less Fuel and Transmission | Increase -Base Rates Per APS Calculation Amount ($000) | Increase -Base Rates Per APS Calculation % | Bill Impacts PSA Impact[11] ($000) | Bill Impacts RES Impact[12] ($000) | Bill Impacts Net of PSA, RES Impact ($000) | Bill Impacts Net Impact on Non-Fuel, Trans % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential | | | | | | | | | | |
| 2 | E-12 | 464,358 | 138,959 | 19,267 | 306,132 | 15,668 | 3.37% | 19,718 | (9,003) | 26,383 | 8.62% |
| 3 | ET-1 | 462,337 | 155,423 | 21,553 | 285,360 | 18,566 | 4.02% | 22,054 | (6,573) | 34,047 | 11.93% |
| 4 | ET-2 | 250,031 | 65,363 | 11,604 | 173,064 | 10,039 | 4.02% | 9,275 | (2,727) | 16,587 | 9.58% |
| 5 | ECT-2 | 104,438 | 51,272 | 5,533 | 47,633 | 4,194 | 4.02% | 7,275 | (916) | 10,553 | 22.15% |
| 6 | ECT-1R | 120,460 | 52,065 | 6,250 | 62,145 | 4,837 | 4.02% | 7,388 | (1,140) | 11,085 | 17.84% |
| 7 | ET-SP | 221 | 86 | 10 | 124 | 8 | 3.62% | 12 | (3) | 17 | 13.68% |
| 8 | E-12 Low Income | 29,008 | 7,891 | 1,434 | 19,683 | 2,035 | 7.02% | - | (801) | 1,234 | 6.27% |
| 9 | ET-1 low income | 18,649 | 5,388 | 997 | 12,263 | 1,309 | 7.02% | - | (366) | 943 | 7.69% |
| 10 | ET-2 low income | 16,008 | 5,258 | 753 | 9,997 | 1,124 | 7.02% | - | (209) | 915 | 9.15% |
| 11 | ECT-2 low income | 2,988 | 1,059 | 182 | 1,747 | 210 | 7.03% | - | (35) | 175 | 10.02% |
| 12 | ECT-1R Low Income | 1,636 | 560 | 109 | 966 | 114 | 6.97% | - | (24) | 90 | 9.31% |
| 13 | Total Residential | 1,470,134 | 483,325 | 67,693 | 919,116 | 58,104 | 3.95% | 65,722 | (21,797) | 102,029 | 11.10% |
| 14 | | | | | | | | | | | |
| 15 | General Service | | | | | | | | | | |
| 16 | E-20 | 3,886 | 1,378 | 295 | 2,213 | 151 | 3.89% | 195 | (127) | 219 | 9.90% |
| 17 | E-30 | 1,406 | 239 | 27 | 1,141 | 35 | 2.49% | 34 | (31) | 38 | 3.33% |
| 18 | E-40 | 1 | - | - | 1 | | | | | | |
| 19 | E-32 XS | 199,177 | 53,311 | 6,037 | 139,829 | 4,435 | 2.23% | 7,565 | (6,017) | 5,983 | 4.28% |
| 20 | E-32 S | 290,021 | 95,881 | 13,992 | 180,148 | 6,441 | 2.22% | 13,605 | (10,847) | 9,199 | 5.11% |
| 21 | E-32 M | 317,315 | 123,216 | 14,631 | 179,468 | 8,791 | 2.77% | 17,484 | (3,834) | 22,441 | 12.50% |
| 22 | E-32 L | 303,798 | 137,027 | 13,648 | 153,123 | 8,418 | 2.77% | 19,444 | (929) | 26,933 | 17.59% |
| 23 | E-32 TOU XS | 633 | 173 | 20 | 440 | 13 | 2.05% | 25 | (13) | 25 | 5.68% |
| 24 | E-32 TOU S | 4,454 | 1,562 | 171 | 2,721 | 88 | 1.98% | 222 | (130) | 180 | 6.62% |
| 25 | E-32 TOU M | 6,385 | 2,628 | 242 | 3,515 | 158 | 2.47% | 373 | (68) | 463 | 13.17% |
| 26 | E-32 TOU L | 22,917 | 11,107 | 880 | 10,931 | 635 | 2.77% | 1,576 | (42) | 2,169 | 19.84% |
| 27 | E-34 | 80,597 | 40,804 | 3,832 | 35,962 | 2,476 | 3.07% | 5,790 | (96) | 8,170 | 22.72% |
| 28 | E-35 | 112,009 | 62,870 | 5,069 | 44,070 | 3,772 | 3.37% | 8,921 | (92) | 12,601 | 28.59% |
| 29 | Total General Service | 1,342,599 | 530,193 | 58,844 | 753,562 | 35,413 | 2.64% | 75,234 | (22,226) | 88,421 | 11.73% |

# ARIZONA PUBLIC SERVICE COMPANY
## ANALYSIS OF BASE REVENUES BY DETAILED CLASS
## TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED

***Revenues without Fuel and Transmission***

| Line No. | Customer Classification and Current Rate Designation | Base Revenues under Present Rates[1] ($000) | 0.037571 Less: Base Fuel | Less: Transmission | Total Revenues Less Fuel and Transmission | Increase - Base Rates Per APS Calculation Amount ($000) | Increase - Base Rates Per APS Calculation % | Bill Impacts: PSA Impact[11] ($000) | Bill Impacts: RES Impact[12] ($000) | Bill Impacts: Net of PSA, RES Impact ($000) | Bill Impacts: Net Impact on Non-Fuel, Trans % |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 30 | | | | | | | | | | | |
| 31 | Irrigation and Water Pumping | 26,669 | 11,771 | 2,069 | 12,829 | 966 | 3.62% | 1,670 | (589) | 2,047 | 15.96% |
| 32 | | | | | | | | | | | |
| 33 | Outdoor Lighting | | | | | | | | | | |
| 34 | E-58 | 10,107 | 1,248 | 138 | 8,721 | 371 | 3.67% | 177 | (89) | 459 | 5.26% |
| 35 | E-59 | 9,701 | 3,513 | 396 | 5,792 | 346 | 3.57% | 498 | (52) | 792 | 13.68% |
| 36 | Contract 12 | 1,013 | 432 | 42 | 539 | 35 | 3.46% | 61 | (18) | 78 | 14.47% |
| 37 | E-67 | 178 | 129 | 13 | 36 | 9 | 5.06% | 18 | (17) | 10 | 27.90% |
| 38 | Total Outdoor Lighting | 20,999 | 5,322 | 590 | 15,087 | 761 | 3.62% | 754 | (176) | 1,339 | 8.87% |
| 39 | | | | | | | | | | | |
| 40 | Dusk to Dawn Lighting | 8,457 | 925 | 104 | 7,428 | 249 | 2.94% | 131 | (123) | 257 | 3.46% |
| 41 | | | | | | | | | | | |
| 42 | Total Sales to Ultimate Retail Customers | 2,868,858 | 1,031,536 | 129,301 | 1,708,022 | 95,493 | 3.33% | 143,511 | (44,911) | 194,093 | 11.36% |

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues based on rates established in Decision No. 71448.
2) Share the Light Rate Schedules are included in Rate Schedule E-58.
3) Rider rate schedules are included in the "Parent" rate schedules listed on schedule H-2 as applicable.
   Riders include: E-3, E-4, CPP-RES, CMPW-01, E-53, E-54, PPR, CPP-GS, Solar-2, Solar-3, GPS-1, GPS-2, GPS-3, EPR-2,EPR-6, E-56, and SC-S.
4) Rate Schedule E-36 is not included as proposed price changes are market-related.
5) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.
7) Transmission revenues based on OATT charges effective during test year.
8) Rate Schedules GS Schools M, GS-Schools L have no revenue or customers.
9) Rate E-40 proposed revenue is reflected in E-32 M
10) Excludes 144,149 MWh of revenue credits, total sales with revenue credits = 27,833,756 MWh
11) Reflects increase in PSA revenues due to requested decrease in base fuel rate.
12) Reflects decrease in RES revenues due to requested transfer of RES funds to base rates.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) |
| ARIZONA PUBLIC SERVICE COMPANY FOR | ) |
| A HEARING TO DETERMINE THE FAIR VALUE | ) |
| OF THE UTILITY PROPERTY OF THE COMPANY | ) Docket No. E-01345A-11-0224 |
| FOR RATEMAKING PURPOSES, TO FIX A JUST | ) |
| AND REASONABLE RATE OF RETURN | ) |
| THEREON, TO APPROVE RATE SCHEDULES | ) |
| DESIGNED TO DEVELOP SUCH RETURN | ) |

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

COST OF SERVICE/RATE DESIGN

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

## Recommended Rate Spread Analysis

| | ACC JURISDICTION | | | | | |
|---|---|---|---|---|---|---|
| | TOTAL RETAIL (5) | RESIDENTIAL (6) | GENERAL SERVICE (7) | E-221 (Water Pumping) (8) | STREET LIGHTING (9) | DUSK TO DAWN (10) |
| Revenues, less Fuel and Transmission | 1,708,022 | 919,116 | 753,562 | 12,829 | 15,087 | 7,428 |
| APS Proposed Increase - Base Rates | 95,493 | 58,104 | 35,413 | 966 | 761 | 249 |
| APS Proposed Net PSA, RES Revenue Increase | *98,600* | 43,925 | 53,008 | 1,081 | 578 | 8 |
| APS Proposed Increase - NET | 194,093 | 102,029 | 88,421 | 2,047 | 1,339 | 257 |
| Percent Increase | 11.36% | 11.10% | 11.73% | 15.96% | 8.87% | 3.46% |
| Total Increase Requested - Equal ROR | 95,493 | 182,265 | (91,358) | 2,448 | 2,351 | (213) |
| APS Proposed Net PSA, RES Revenue Increase | 98,600 | 43,925 | 53,008 | 1,081 | 578 | 8 |
| Total Increase @ Equal ROR - NET | 194,093 | 226,190 | (38,350) | 3,529 | 2,929 | (205) |
| Percent Increase | 11.36% | 24.61% | -5.09% | 27.51% | 19.41% | -2.76% |
| Recommended Proposed Rate Spread - Percent Incre | 11.36% | 14.36% | 7.63% | 14.36% | 14.36% | 7.63% |
| Total Increase @ Equal ROR - NET | 194,093 | 132,018 | 57,498 | 1,843 | 2,167 | 567 |
| Percentage Point Deviation From Average Increase | 0.00% | 3.00% | -3.73% | 3.00% | 3.00% | -3.73% |

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) |
| ARIZONA PUBLIC SERVICE COMPANY FOR | ) |
| A HEARING TO DETERMINE THE FAIR VALUE | ) |
| OF THE UTILITY PROPERTY OF THE COMPANY | ) Docket No. E-01345A-11-0224 |
| FOR RATEMAKING PURPOSES, TO FIX A JUST | ) |
| AND REASONABLE RATE OF RETURN | ) |
| THEREON, TO APPROVE RATE SCHEDULES | ) |
| DESIGNED TO DEVELOP SUCH RETURN | ) |

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

COST OF SERVICE/RATE DESIGN

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

# RATE E-32 L
## TYPICAL BILL ANALYIS - WINTER

| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Components of Proposed Bill: Base | Components of Proposed Bill: Transmission | Monthly Bill under Proposed Rates | Change: Amount($) | Change: % | Impact of PSA Roll-in | Impact of RES/REAC Roll-in | Net Change: Amount($) | Net Change: % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 401 | 15% | 43,910 | 6,191.67 | 7,301.67 | 635.59 | 7,937.26 | 1,745.58 | 28.2% | 234.09 | (89.37) | 1,890.30 | 30.5% |
| 401 | 30% | 87,819 | 9,573.93 | 9,167.38 | 635.59 | 9,802.97 | 229.04 | 2.4% | 468.19 | (89.37) | 607.86 | 6.3% |
| 401 | 45% | 131,729 | 11,435.26 | 11,033.10 | 635.59 | 11,668.69 | 233.43 | 2.0% | 702.28 | (89.37) | 846.34 | 7.4% |
| 401 | 60% | 175,638 | 13,296.58 | 12,898.81 | 635.59 | 13,534.40 | 237.82 | 1.8% | 936.38 | (89.37) | 1,084.83 | 8.2% |
| 401 | 75% | 219,548 | 15,157.90 | 14,764.53 | 635.59 | 15,400.12 | 242.21 | 1.6% | 1,170.47 | (89.37) | 1,323.31 | 8.7% |
| 600 | 15% | 65,700 | 9,022.22 | 10,677.83 | 951.00 | 11,628.83 | 2,606.61 | 28.9% | 350.27 | (89.37) | 2,867.51 | 31.8% |
| 600 | 30% | 131,400 | 14,082.96 | 13,469.43 | 951.00 | 14,420.43 | 337.47 | 2.4% | 700.53 | (89.37) | 948.63 | 6.7% |
| 600 | 45% | 197,100 | 16,867.98 | 16,261.02 | 951.00 | 17,212.02 | 344.04 | 2.0% | 1,050.80 | (89.37) | 1,305.47 | 7.7% |
| 600 | 60% | 262,800 | 19,653.00 | 19,052.61 | 951.00 | 20,003.61 | 350.61 | 1.8% | 1,401.07 | (89.37) | 1,662.30 | 8.5% |
| 600 | 75% | 328,500 | 22,438.03 | 21,844.21 | 951.00 | 22,795.21 | 357.18 | 1.6% | 1,751.33 | (89.37) | 2,019.14 | 9.0% |
| 800 | 15% | 87,600 | 11,866.99 | 14,070.96 | 1,268.00 | 15,338.96 | 3,471.97 | 29.3% | 467.02 | (89.37) | 3,849.62 | 32.4% |
| 800 | 30% | 175,200 | 18,614.64 | 17,793.09 | 1,268.00 | 19,061.09 | 446.45 | 2.4% | 934.04 | (89.37) | 1,291.12 | 6.9% |
| 800 | 45% | 262,800 | 22,328.00 | 21,515.21 | 1,268.00 | 22,783.21 | 455.21 | 2.0% | 1,401.07 | (89.37) | 1,766.90 | 7.9% |
| 800 | 60% | 350,400 | 26,041.37 | 25,237.34 | 1,268.00 | 26,505.34 | 463.97 | 1.8% | 1,868.09 | (89.37) | 2,242.68 | 8.6% |
| 800 | 75% | 438,000 | 29,754.73 | 28,959.46 | 1,268.00 | 30,227.46 | 472.73 | 1.6% | 2,335.11 | (89.37) | 2,718.47 | 9.1% |
| 1,000 | 15% | 109,500 | 14,711.76 | 17,464.10 | 1,585.00 | 19,049.10 | 4,337.34 | 29.5% | 583.78 | (89.37) | 4,831.74 | 32.8% |
| 1,000 | 30% | 219,000 | 23,146.32 | 22,116.75 | 1,585.00 | 23,701.75 | 555.43 | 2.4% | 1,167.56 | (89.37) | 1,633.61 | 7.1% |
| 1,000 | 45% | 328,500 | 27,788.03 | 26,769.41 | 1,585.00 | 28,354.41 | 566.38 | 2.0% | 1,751.33 | (89.37) | 2,228.34 | 8.0% |
| 1,000 | 60% | 438,000 | 32,429.73 | 31,422.06 | 1,585.00 | 33,007.06 | 577.33 | 1.8% | 2,335.11 | (89.37) | 2,823.07 | 8.7% |
| 1,000 | 75% | 547,500 | 37,071.44 | 36,074.72 | 1,585.00 | 37,659.72 | 588.28 | 1.6% | 2,918.89 | (89.37) | 3,417.79 | 9.2% |
| 1,500 | 15% | 164,250 | 21,823.69 | 25,946.92 | 2,377.50 | 28,324.42 | 6,500.74 | 29.8% | 875.67 | (89.37) | 7,287.03 | 33.4% |
| 1,500 | 30% | 328,500 | 34,475.53 | 32,925.91 | 2,377.50 | 35,303.41 | 827.88 | 2.4% | 1,751.33 | (89.37) | 2,489.84 | 7.2% |
| 1,500 | 45% | 492,750 | 41,438.08 | 39,904.89 | 2,377.50 | 42,282.39 | 844.31 | 2.0% | 2,627.00 | (89.37) | 3,381.93 | 8.2% |
| 1,500 | 60% | 657,000 | 48,400.64 | 46,883.87 | 2,377.50 | 49,261.37 | 860.73 | 1.8% | 3,502.67 | (89.37) | 4,274.02 | 8.8% |
| 1,500 | 75% | 821,250 | 55,363.20 | 53,862.85 | 2,377.50 | 56,240.35 | 877.15 | 1.6% | 4,378.33 | (89.37) | 5,166.11 | 9.3% |
| 3,000 | 15% | 328,500 | 43,159.46 | 51,395.41 | 4,755.00 | 56,150.41 | 12,990.95 | 30.1% | 1,751.33 | (268.13) | 14,474.15 | 33.5% |
| 3,000 | 30% | 657,000 | 68,463.14 | 65,353.37 | 4,755.00 | 70,108.37 | 1,645.23 | 2.4% | 3,502.67 | (268.13) | 4,879.77 | 7.1% |
| 3,000 | 45% | 985,500 | 82,388.26 | 79,311.34 | 4,755.00 | 84,066.34 | 1,678.08 | 2.0% | 5,254.00 | (268.13) | 6,663.95 | 8.1% |
| 3,000 | 60% | 1,314,000 | 96,313.37 | 93,269.30 | 4,755.00 | 98,024.30 | 1,710.93 | 1.8% | 7,005.33 | (268.13) | 8,448.13 | 8.8% |
| 3,000 | 75% | 1,642,500 | 110,238.49 | 107,227.27 | 4,755.00 | 111,982.27 | 1,743.78 | 1.6% | 8,756.66 | (268.13) | 10,232.31 | 9.3% |

**RATE E-32 L**
**TYPICAL BILL ANALYIS - SUMMER**

| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Components of Proposed Bill: Base | Components of Proposed Bill: Transmission | Monthly Bill under Proposed Rates | Change: Amount($) | Change: % | Impact of PSA Roll-in | Impact of RES/REAC Roll-in | Net Change: Amount($) | Net Change: % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 401 | 15% | 43,910 | 6,921.89 | 8,041.98 | 635.59 | 8,677.57 | 1,755.68 | 25.4% | 234.09 | (89.37) | 1,900.40 | 27.5% |
| 401 | 30% | 87,819 | 11,034.36 | 10,648.01 | 635.59 | 11,283.60 | 249.24 | 2.3% | 468.19 | (89.37) | 628.05 | 5.7% |
| 401 | 45% | 131,729 | 13,625.90 | 13,254.04 | 635.59 | 13,889.63 | 263.73 | 1.9% | 702.28 | (89.37) | 876.64 | 6.4% |
| 401 | 60% | 175,638 | 16,217.44 | 15,860.07 | 635.59 | 16,495.66 | 278.22 | 1.7% | 936.38 | (89.37) | 1,125.22 | 6.9% |
| 401 | 75% | 219,548 | 18,808.98 | 18,466.10 | 635.59 | 19,101.69 | 292.71 | 1.6% | 1,170.47 | (89.37) | 1,373.81 | 7.3% |
| 600 | 15% | 65,700 | 10,114.81 | 11,785.54 | 951.00 | 12,736.54 | 2,621.72 | 25.9% | 350.27 | (89.37) | 2,882.62 | 28.5% |
| 600 | 30% | 131,400 | 16,268.14 | 15,684.83 | 951.00 | 16,635.83 | 367.69 | 2.3% | 700.53 | (89.37) | 978.85 | 6.0% |
| 600 | 45% | 197,100 | 20,145.75 | 19,584.13 | 951.00 | 20,535.13 | 389.37 | 1.9% | 1,050.80 | (89.37) | 1,350.80 | 6.7% |
| 600 | 60% | 262,800 | 24,023.37 | 23,483.42 | 951.00 | 24,434.42 | 411.05 | 1.7% | 1,401.07 | (89.37) | 1,722.75 | 7.2% |
| 600 | 75% | 328,500 | 27,900.98 | 27,382.72 | 951.00 | 28,333.72 | 432.73 | 1.6% | 1,751.33 | (89.37) | 2,094.69 | 7.5% |
| 800 | 15% | 87,600 | 13,323.78 | 15,547.90 | 1,268.00 | 16,815.90 | 3,492.12 | 26.2% | 467.02 | (89.37) | 3,869.77 | 29.0% |
| 800 | 30% | 175,200 | 21,528.21 | 20,746.96 | 1,268.00 | 22,014.96 | 486.75 | 2.3% | 934.04 | (89.37) | 1,331.42 | 6.2% |
| 800 | 45% | 262,800 | 26,698.37 | 25,946.02 | 1,268.00 | 27,214.02 | 515.65 | 1.9% | 1,401.07 | (89.37) | 1,827.35 | 6.8% |
| 800 | 60% | 350,400 | 31,868.52 | 31,145.08 | 1,268.00 | 32,413.08 | 544.56 | 1.7% | 1,868.09 | (89.37) | 2,323.28 | 7.3% |
| 800 | 75% | 438,000 | 37,038.67 | 36,344.14 | 1,268.00 | 37,612.14 | 573.47 | 1.5% | 2,335.11 | (89.37) | 2,819.21 | 7.6% |
| 1,000 | 15% | 109,500 | 16,532.75 | 19,310.27 | 1,585.00 | 20,895.27 | 4,362.52 | 26.4% | 583.78 | (89.37) | 4,856.92 | 29.4% |
| 1,000 | 30% | 219,000 | 26,788.29 | 25,809.09 | 1,585.00 | 27,394.09 | 605.80 | 2.3% | 1,167.56 | (89.37) | 1,683.98 | 6.3% |
| 1,000 | 45% | 328,500 | 33,250.98 | 32,307.92 | 1,585.00 | 33,892.92 | 641.93 | 1.9% | 1,751.33 | (89.37) | 2,303.89 | 6.9% |
| 1,000 | 60% | 438,000 | 39,713.67 | 38,806.74 | 1,585.00 | 40,391.74 | 678.07 | 1.7% | 2,335.11 | (89.37) | 2,923.81 | 7.4% |
| 1,000 | 75% | 547,500 | 46,176.36 | 45,305.57 | 1,585.00 | 46,890.57 | 714.21 | 1.5% | 2,918.89 | (89.37) | 3,543.72 | 7.7% |
| 1,500 | 15% | 164,250 | 24,555.16 | 28,716.18 | 2,377.50 | 31,093.68 | 6,538.52 | 26.6% | 875.67 | (89.37) | 7,324.81 | 29.8% |
| 1,500 | 30% | 328,500 | 39,938.48 | 38,464.42 | 2,377.50 | 40,841.92 | 903.43 | 2.3% | 1,751.33 | (89.37) | 2,565.39 | 6.4% |
| 1,500 | 45% | 492,750 | 49,632.52 | 48,212.65 | 2,377.50 | 50,590.15 | 957.64 | 1.9% | 2,627.00 | (89.37) | 3,495.26 | 7.0% |
| 1,500 | 60% | 657,000 | 59,326.55 | 57,960.89 | 2,377.50 | 60,338.39 | 1,011.84 | 1.7% | 3,502.67 | (89.37) | 4,425.13 | 7.5% |
| 1,500 | 75% | 821,250 | 69,020.59 | 67,709.13 | 2,377.50 | 70,086.63 | 1,066.04 | 1.5% | 4,378.33 | (89.37) | 5,355.00 | 7.8% |
| 3,000 | 15% | 328,500 | 48,622.42 | 56,933.92 | 4,755.00 | 61,688.92 | 13,066.50 | 26.9% | 1,751.33 | (268.13) | 14,549.70 | 29.9% |
| 3,000 | 30% | 657,000 | 79,389.05 | 76,430.39 | 4,755.00 | 81,185.39 | 1,796.34 | 2.3% | 3,502.67 | (268.13) | 5,030.88 | 6.3% |
| 3,000 | 45% | 985,500 | 98,777.12 | 95,926.87 | 4,755.00 | 100,681.87 | 1,904.75 | 1.9% | 5,254.00 | (268.13) | 6,890.61 | 7.0% |
| 3,000 | 60% | 1,314,000 | 118,165.19 | 115,423.34 | 4,755.00 | 120,178.34 | 2,013.15 | 1.7% | 7,005.33 | (268.13) | 8,750.35 | 7.4% |
| 3,000 | 75% | 1,642,500 | 137,553.26 | 134,919.82 | 4,755.00 | 139,674.82 | 2,121.55 | 1.5% | 8,756.66 | (268.13) | 10,610.09 | 7.7% |

Kroger Ex. 3

ORIGINAL


BOEHM, KURTZ & LOWRY
ATTORNEYS AT LAW
36 EAST SEVENTH STREET
SUITE 1510
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255
TELECOPIER (513) 421-2764


RECEIVED
2012 JAN 18 P 2:03
AZ CORP COMMISSION
DOCKET CONTROL

EXHIBIT
Kroger-3
ADMITTED

Arizona Corporation Commission
DOCKETED
JAN 18 2012
DOCKETED BY

**Via Overnight Mail**

January 17, 2012

Arizona Corporation Commission
Attn: Docket Filing Window
1200 West Washington Street
Phoenix, AZ 85007

***Re: Docket No. E-01345A-11-0224***

Dear Sir or Madam:

Attached please find the original and 13 copies each of the TESTIMONY IN SUPPORT OF SETTLEMENT OF STEPHEN J. BARON on behalf of THE KROGER CO. for filing in the above-referenced matter.

All parties of record have been served. Please place this document of file.

Very Truly Yours,

Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

John William Moore, Jr., (Az. Bar No. 021942)

**COUNSEL FOR THE KROGER CO.**

KJB/kew
Attachments

G:\WORK\MLK\KROGER\ARIZONA\E-01345A-11-0224 (Arizona Public Service)\Commission ltr.docx

## CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by electronic mail (when available) or regular U.S. mail 18th day of January 2012 on the parties listed below.

Kurt J. Boehm, Esq.
John William Moore., Jr., (Az Bar NO. 021942)

| Company | Contact | Address |
|---|---|---|
| | Mel Beard | 4108 W. Calle Lejos<br>Glendale, Arizona 85310 |
| | Steve Chriss | 2011 S.E. 10th St.<br>Bentonville, Arkansas 72716-0500 |
| | Craig Marks | 10645 N. Tatum Blvd.<br>Suite 200-676<br>Phoenix, Arizona 85028 |
| | Scott Wakefield | 201 N. Central Ave., Suite 3300<br>Phoenix, Arizona 85004-1052 |
| | Jay Moyes | 1850 N. Central Ave. - 1100<br>Phoenix, Arizona 85004 |
| | Jeffrey Woner | K.R. SALINE & ASSOC., PLC<br>160 N. Pasadena, Suite 101<br>Mesa, Arizona 85201 |
| | Lawrence Robertson, Jr. | PO Box 1448<br>Tubac, Arizona 85646 |
| | Laura Sanchez | P.O. Box 287<br>Albuquerque, New Mexico 87103 |
| | Nicholas Enoch | 349 N. Fourth Ave.<br>Phoenix, Arizona 85003 |
| | Greg Patterson | 2398 E. Camelback Rd., Ste. 240<br>Phoenix, Arizona 85016 |
| | Karen White | AFLOA/JACL-ULT<br>139 Barnes Drive<br>Tyndall Air Force Base, Florida 32403 |
| | Gary Yaquinto | Arizona Utiltiy Investors Association<br>2100 North Central Avenue, Suite 210<br>Phoenix, Arizona 85004 |
| | Michael Grant | 2575 E. Camelback Rd.<br>Phoenix, Arizona 85016-9225 |
| | Jeffrey Crockett | One E. Washington St., Ste. 2400<br>Phoenix, Arizona 85004 |
| | Michael Patten | 400 E. Van Buren St. - 800<br>Phoenix, Arizona 85004-3906 |
| | Cynthia Zwick | 1940 E. Luke Avenue<br>Phoenix, Arizona 85016 |
| | John Moore, Jr. | 7321 N. 16th Street<br>Phoenix, Arizona 85020 |

| | | |
|---|---|---|
| | Bradley Carroll | One South Church Ave., Ste. UE201<br>Tucson, Arizona 85701 |
| | Timothy Hogan | 202 E. McDowell Rd. - 153<br>Phoenix, Arizona 85004 |
| | David Berry | P.O. Box 1064<br>Scottsdale, Arizona 85252-1064 |
| | Barbara Wyllie-Pecora | 14410 W. Gunsight Dr.<br>Sun City West, Arizona 85375 |
| | Michael Curtis | 501 East Thomas Road<br>Phoenix, Arizona 85012-3205 |
| | Daniel Pozefsky | 1110 West Washington, Suite 220<br>Phoenix, Arizona 85007 |
| | C. Webb Crockett | 3003 N. Central Ave. - 2600<br>Phoenix, Arizona 85012-2913 |
| | Janice Alward | 1200 W. Washington<br>Phoenix, Arizona 85007 |
| | Steve Olea | 1200 W. Washington St.<br>Phoenix, Arizona 85007 |
| Arizona Corporation Commission | Lyn Farmer | 1200 W. Washington<br>Phoenix, Arizona 85007-2927 |
| | Meghan Grabel | P.O. Box 53999, Station 8695<br>Phoenix, Arizona 85072-3999 |

**BEFORE THE ARIZONA CORPORATION COMMISSION**

RECEIVED

2012 JAN 18 P 2: 04

AZ CORP COMMISSION
DOCKET CONTROL

**COMMISSIONERS**

**GARY PIERCE, CHAIRMAN**
**BOB STUMP**
**SANDRA D. KENNEDY**
**PAUL NEWMAN**
**BRENDA BURNS**

| | |
|---|---|
| **IN THE MATTER OF THE APPLICATION OF** | ) |
| **ARIZONA PUBLIC SERVICE COMPANY FOR** | ) |
| **A HEARING TO DETERMINE THE FAIR VALUE** | ) |
| **OF THE UTILITY PROPERTY OF THE COMPANY** | ) **Docket No. E-01345A-11-0224** |
| **FOR RATEMAKING PURPOSES, TO FIX A JUST** | ) |
| **AND REASONABLE RATE OF RETURN** | ) |
| **THEREON, TO APPROVE RATE SCHEDULES** | ) |
| **DESIGNED TO DEVELOP SUCH RETURN** | ) |

# TESTIMONY IN SUPPORT OF SETTLEMENT

**OF**

**STEPHEN J. BARON**

**ON BEHALF OF THE**

**KROGER CO.**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**January 2012**

**BEFORE THE**

**ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| **IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN** | **) Docket No. E-01345A-11-0224** |

**TESTIMONY IN SUPPORT OF SETTLEMENT OF STEPHEN J. BARON**

**Q. Please state your name and business address.**

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

**Q. Have you previously presented testimony before the Arizona Corporation Commission?**

A. Yes. I presented testimony in three previous Arizona Public Service Company rate cases on behalf of Kroger Co. in 2004, 2006 and in 2008 (Docket Nos. E-01345-03-0437, E-01345A-05-0816 and E-01345A-08-0172). I also presented testimony in two Tucson Electric Power Company proceedings; in 1981 on behalf of the Commission (Docket No. U-1933I) and in 2008 on behalf of Kroger Co. (Docket No. E-01933A-07-0402).

**Q. Have you previously submitted testimony in the proceeding?**

A. Yes. I submitted Direct Testimony on Cost of Service/Rate Design and Decoupling.

**Q. What is the purpose of your Testimony?**

A. I will be presenting brief testimony in support of the Proposed Rate Settlement Agreement of January 6, 2012 ("Settlement Agreement"). Kroger is a signatory to this agreement and fully supports the settlement for the reasons that I will discuss below. Kroger did not present testimony on the overall level of APS's revenue requirement increase. Our testimony was limited to the allocation of the overall approved revenue increase to rate classes, specific rate design issues affecting general service rates and proposals regarding a decoupling mechanism. Notwithstanding this, Kroger supports the entire settlement and believes that it will result in reasonable rates.

**Q. Have you specifically reviewed the provisions of the settlement regarding revenue requirement?**

A. Yes. The proposed Settlement contemplates that APS receive a base rate increase of zero dollars. This amount is comprised of: (1) a non-fuel base rate increase of $116.3 million, which includes providing for a return on and of plant that is in service as of March 31, 2012; (2) a fuel base rate decrease of $153.1 million; and (3) a transfer of cost recovery from the Renewable Energy Surcharge to base rates. I believe that this is a reasonable settlement result.

**Q. Have you reviewed the proposed settlement rate design for large commercial customer rate schedules?**

A. Yes. Based on my review of the proposed tariffs and the issues that I addressed in my Direct Testimony in this case, I believe that the proposed settlement is reasonable and consistent with the underlying cost of service. I therefore fully support and recommend approval of the Settlement Agreement.

**Q. Have you reviewed the proposed settlement provisions concerning the Lost Fixed Cost Recovery ("LFCR") mechanism?**

ALJ
E32-L
AG-1

A. Yes. Kroger supports the provision of the LFCR mechanism that exempts E-32 L, E-32 L TOU and other schedules consisting of large business customers from the LFCR mechanism. It is appropriate to exempt these customers from the LFCR mechanism because the level of costs recovered through demand charges in these schedules is sufficiently high to significantly reduce the revenue risk to the Company as a result of energy conservation.

would all of Kroger's load under AG-1?

**Q. Are there additional reasons why you believe that the Commission should approve the Settlement Agreement?**

A. Yes. The rate case stability provision, freezing base rates until July 1, 2016 is likely to be of significant benefit to all of the Company's ratepayers.

Additionally, Kroger supports the proposed Experimental Rate Schedule AG-1. Kroger is hopeful that the AG-1 rate will result in savings for large commercial customers.

**Q. Does that complete your testimony?**

A. Yes

## AFFIDAVIT

STATE OF GEORGIA )

COUNTY OF FULTON )

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this 17th day of January 2012.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

EXHIBIT

NRDC-1

ADMITTED

Laura E. Sanchez
NATURAL RESOURCES
DEFENSE COUNCIL
PO Box 65623
Albuquerque, NM 87193
(505) 352-7408
lsanchez@nrdc.org

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE – Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| 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-11-0224<br><br>**NRDC's NOTICE OF DIRECT TESTIMONY** |

Natural Resources Defense Council ("NRDC") by and through its attorney hereby files the Direct Testimony of its Witness Ralph Cavanagh in the above-referenced matter.

RESPECTFULLY SUBMITTED this 17th day of November, 2011.

By ______________________
Laura E. Sanchez
NRDC
PO Box 65623
Albuquerque, NM 87193

ORIGINAL and 13 COPIES of the foregoing filed this 17th day of November, 2011 to:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing
electronically mailed this
13th day of November, 2011 to:

All Parties of Record

By: ______________________

## TABLE OF CONTENTS

BEFORE THE ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY

OF

RALPH CAVANAGH

**SECTION I - Introduction**

Q. Please state your name, address, and employment.

A. My name is Ralph Cavanagh. I am the Energy Program Co-Director for the Natural Resources Defense Council ("NRDC"), 111 Sutter Street, 20th Floor, San Francisco, CA 94104.

Q. Please outline your educational background and professional experience.

A. I am a graduate of Yale College and Yale Law School, and I joined NRDC in 1979. I am a member of the faculty of the University of Idaho's Utility Executive Course, and I have been a Visiting Professor of Law at Stanford and the University of California. From 1993-2003, I served as a member of the U.S. Secretary of Energy's Advisory Board, and I am now a member of the Department of Energy's Electricity Advisory Board. My current board memberships include the Bipartisan Policy Center, the Bonneville Environmental Foundation, the Center for Energy Efficiency and Renewable Technologies, the Renewable Northwest Project, and the Northwest Energy Coalition. I have received the Mary Kilmarx Award from the National Association of Regulatory Utility Commissioners (2007), the Heinz Award for Public Policy (1996) and the Bonneville Power Administration's Award for Exceptional Public Service

(1986). Prior to 2011, I had not testified before the Arizona Corporation Commission in at least two decades, but I was an invited participant in the workshops that preceded the Commission's adoption last December of its Final Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Final Policy Statement"). I also filed testimony for NRDC in support of the Southwest Gas Company's "energy efficiency enabling provision," a revenue-per-customer decoupling mechanism that was included in an application now pending before the Commission.

Q. On whose behalf are you testifying?

A. I am testifying for the Natural Resources Defense Council (NRDC).

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

A. My testimony supports the Arizona Public Service Company's ("APS") proposal for an Efficiency and Infrastructure Account ("EIA") mechanism.

**SECTION II - Summary of Testimony**

Q. Summarize your conclusions and recommendations.

A. I agree with APS that its proposed EIA "is necessary given the [Commission's] ambitious Energy

Efficiency Standard and increasing DG requirements," because "without [the EIA], successful energy efficiency programs - even at levels below that set by the Commission in the EES - create a significant disincentive for the utility with serious adverse financial impacts."[1] The company's General Rate Case Application appropriately links the EIA to "the Commission's recently approved decoupling policy statement," and indicates that the EIA would "address the loss in fixed cost recovery that occurs when the historical volumetric pricing structure is used in combination with increasing energy efficiency and distributed generation requirements."[2] To underscore the EIA's importance and urgency, APS notes that in its 2010 Test Year it collected more than two-thirds of the fixed costs of serving its residential and commercial through volumetric charges.[3]

I conclude that the proposed EIA is entirely consistent with the Commission's decoupling policy statement, and I recommend its approval. My testimony summarizes experience with comparable revenue decoupling

---

[1] See Testimony of Leland R. Snook on behalf of APS, p. 2:17-28.
[2] Arizona Public Service Commission, Docket No. E-01345A-11-0224, Application (June 1, 2011), p. 6.
[3] See Testimony of Leland R. Snook, p. 3 (noting that APS collected 73% of residential sector fixed costs and 66% of commercial sector fixed costs, respectively, through kWh charges).

mechanisms and responds to concerns commonly raised about them. APS's proposal would remove a potent disincentive to the company's engagement with all forms of progress in energy efficiency and distributed generation, by ensuring that the Company recovers the fixed costs previously authorized by the Commission (but no more than that amount), notwithstanding any short-term fluctuations in metered electricity use. My testimony also shows that efforts to link rate adjustments specifically to energy efficiency program impacts would have perverse consequences and impede statewide progress in achieving cost-effective savings.

My testimony anticipates and rebuts claims that approval of APS's proposal should be linked to reductions in its return on equity. I am aware of no evidence that decoupling mechanisms have reduced any utility's cost of capital, and customer benefits from the proposed mechanism are illustrated by the specific reference in the Commission's policy statement to opportunities for "direct bill savings to [APS] ratepayers on the order of $4.6 billion between 2011 and 2030", which "were principally driven by utility plant deferrals and by reductions in utility fuel and purchased power budgets" associated with the enhanced energy efficiency efforts required to comply with the Commission's Energy Efficiency Standard.[4] Reducing the Company's authorized return on equity ("ROE") would undercut a principal rationale for the Commission's Final Policy Statement, which was to "encourage and enable aggressive use of demand side management programs and the achievement of Arizona's Electric and Gas Energy Efficiency Standards, which will benefit ratepayers and minimize utility costs."[5]

**SECTION III - Energy Efficiency Benefits to APS Customers**

Q. What is the source of that estimate of $4.6 billion in net energy-efficiency benefits to APS customers[6], and why is it different from the $8.9 billion figure that appears in Mr. Leland Snook's testimony for APS (p. 12:1 & n. 3)?

A. Both numbers appear in a comprehensive analysis by the Lawrence Berkeley National Laboratory, which was initially presented during the Commission's workshops and later published in a document that is attached as an exhibit to this testimony (A. Satchwell, P. Cappers & C. Goldman, <u>Carrots and Sticks: A Comprehensive Business Model for the Successful Achievement of Energy</u>

[4] See Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314, (Dec. 29, 2010), p. 20 (comparing "high efficiency scenario" to "the business as usual case").
[5] Id. at p. 30.
[6] See this testimony, p. 4:20-21.

Efficiency Resource Standards (March 2011) [EXHIBIT NRDC-1]. The period covered by the estimates runs from 2011 through 2030; the higher ($8.9 billion) number reflects the difference between achieving the state's EES targets and a "business as usual" case involving no utility intervention to promote energy efficiency. The lower ($4.6 billion) number is the difference between reaching the EES targets and maintaining the current level of savings from utility programs. Both numbers "are net of the costs of energy efficiency programs (e.g., the costs of administering the program, incentives to customers)." Id. at p. 10.

**SECTION IV – The APS Proposal is Consistent with the Commission's Statement on Energy Efficiency and Decoupling**

Q. What is the basis for your conclusion that APS's proposal is consistent with the Commission's Final Policy Statement?

A. APS has proposed a revenue per-customer decoupling mechanism, which includes an annual adjustment to reconcile actual and allowed fixed cost recovery,[7] enhanced bill stability "by mitigating the impact of

---

[7] In the EIA proposal, "fixed costs" appropriately include "virtually all base rate costs, except for fuel and transmission costs, which are determined to be fixed cost in the most recent cost of service study," which itself is based on the NARUC Electric Utility Cost Allocation Manual. "Other costs that vary in the short-term with sales levels are also excluded from the mechanism, primarily generation maintenance costs." See Testimony of Leland R. Snook, p. 15:16-23 & n. 6.

weather for customers," broad inclusion of customer classes (except for those with non-metered accounts and large gas-fired plants not included in energy efficiency programs), and a three percent limit on potential surcharges associated with the mechanism (but no limit on potential rate reductions).[8] APS also "proposes to aggregate all of the differences between authorized and actual fixed cost recovery for each customer class," and to allocate the "total amount of over or under-recovery of fixed costs … to each customer class on an equal percentage basis," in order "to provide customers with greater rate stability."[9]

The Commission anticipated and encouraged all of these decoupling elements in its Final Policy Statement:

- "Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency . . ." [p. 30, item 3]

- "[N]on-fuel revenue per customer decoupling may be well suited for Arizona as it responds to customer growth and is better suited to address the issues associated with customer growth." [p. 30, item 4]

- "Adoption of decoupling . . . should not occur as a pilot, as this insufficiently supports demand side management efforts, discourages beneficial changes in

---

[8] See Testimony of Leland R. Snook, including Attachment LRS-1, which illustrates the operation of the proposed EIA. "If in any year the cap is exceeded APS proposes to defer that amount with interest until such time as it can be included in the annual adjustment without reaching the cap." Id., p. 21:6-9.

[9] Id. at p. 19:9-16.

rate design and is unlikely to encourage financial ratings improvements." [p. 30, item 5]

- "Full decoupling is preferable to partial decoupling ..." [p. 31, item 8]

- "Decoupling adjustments should occur at least on an annual basis; however, parties may propose more current adjustments as this may provide ratepayers with weather related relief following extreme events." [p. 31, item 10]

- "Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes." [p. 31, item 11]

- "Decoupling adjustments should be blended and applied across customer classes to discourage dramatic changes experienced by any one class." [p. 31, item 12]

**SECTION V - Experience with Revenue Decoupling in Other States**

Q. Describe experience with revenue decoupling elsewhere in the country.

A. Nationally, the count of states with decoupling for at least one utility stands at 14 for electricity and 22 for natural gas. In the West, Hawaii, California, Idaho and Oregon have adopted decoupling for at least one electric utility; Washington's Commission is now considering such mechanisms for its two largest electric utilities, Avista and Puget Power. California, Utah, Oregon, Washington and Wyoming have adopted natural gas decoupling mechanisms. New Mexico's Public Service Commission has left open "the determination of whether a decoupling mechanism should be approved or required for any utility," and the New Mexico Legislature has acknowledged the need to "identify regulatory disincentives or barriers for public utility expenditures on energy efficiency and load management measures and ensure that they are removed in a manner that balances the public interest, consumers' interests and investors' interests."[10]

**SECTION VI – Rate Impacts of APS's Proposal**

Q. What about rate impacts of revenue decoupling?

A. Neither revenue decoupling in general nor the APS proposal in particular add any additional costs to utility bills; they simply ensure that previously approved fixed costs are neither over- nor under-recovered. In terms of rate adjustments to achieve this objective, industry experience shows that effects are minimal in practice, with adjustments that go in both directions. A comprehensive industry-wide assessment found that, of 88 gas and electric rate adjustments from 2000-2009 under decoupling mechanisms, less than one-seventh involved increases exceeding 3 percent. (Refunds accounted for a much larger fraction.) Typical adjustments in utility bills "amount[ed] to less than $1.50 per month in higher or lower charges for residential gas customers and less than

[10] See Case No. 08-00024-UT, Final Order Repealing and Replacing 17.7.2 NMAC (2010), p. 10; Efficient Use of Energy Act, Section 62-17-5.F.

$2.00 per month . . . for residential electric customers."[11] For electric bills, that represents less than seven cents a day in annual variations for the average household, which hardly seems like dangerous rate volatility, particularly since it sometimes comes in the form of a rebate - and serves only to ensure that the utility recovers no more and no less than the fixed costs of service that regulators have reviewed and approved.

**SECTION VII - Revenue Decoupling Does Not Reduce the Incentive to Save Energy**

Q. What do you say to those who are concerned that revenue decoupling reduces incentives to save energy, by raising rates and depriving customers of rewards from consumption reductions?

A. Experience proves the opposite: revenue decoupling results in trivial rate adjustments that go both ways, and do not materially affect rewards for saving electricity and natural gas. As the Oregon Public Utility Commission found when it adopted a decoupling mechanism for Portland General Electric in January 2009, responding to analogous claims that decoupling would rob customers of the rewards of conservation: "We believe the opposite is true: an individual customer's action to reduce usage will have

---

[11] See Pamela Lesh, Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review, Electricity Journal (October 2009), p. 67.

no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient." Oregon PUC Order No. 09-020, p. 28 (Jan. 2009).

Finally, note that unlike so-called "fixed-variable rate designs" that load fixed costs into monthly customer charges, APS's proposal does not establish a high fixed minimum bill that would greatly reduce customers' rewards for saving electricity; if all its fixed costs were recovered in that way, APS would need to raise the basic service charge for residential service "to over $90 per month," and "General Service customers would experience even larger increases."[12]

**SECTION VIII - Approving APS's Proposal Should Not Result in an Adjustment in Its Authorized Return on Equity**

Q. Explain your conclusion that approving APS's proposal should not result in an adjustment in its authorized return on equity.

A. In this I am of course echoing the Commission's conclusion in the Final Policy Statement: "Commitment to and early implementation of decoupling should precede significant decoupling-specific adjustments to cost of capital if a revenue per customer decoupling

[12] Testimony of Leland R. Snook, p. 8:14-17.

mechanism is approved for a utility."[13] The data summarized earlier from Pamela Lesh's Electricity Journal study provide additional support for my recommendation: rate impacts this modest (typically averaging less than seven cents per household per day) simply do not imply appreciable consequences for company-wide cost of capital, and I have seen no empirical evidence to the contrary. Indeed, in the specific context of natural gas utility decoupling, a March 2011 investigation by the Brattle Group reached the opposite conclusion:

> The findings of our analysis do not support the belief that utilities with decoupling have a lower cost of capital than utilities without decoupling. Contrary to what some might expect to find, at least on the basis of the opinions of certain intervenors and the (minority set of) judgments where commissions reduced allowed rates of return because of decoupling, we found that the estimated cost of capital for decoupled utilities was higher by a small but statistically significant amount (emphasis in original).[14]

**SECTION IX - Adjustments Keyed Solely to Adjudicated Savings Would Mean Automatic Annual Rate Increases**

Q. Why shouldn't the Commission amend the proposal so that adjustments track only electricity savings attributable to the Company's energy efficiency programs?

---

[13] Final ACC Policy Statement, note 4 above, p. 31 [item 6].
[14] J. Wharton, M. Vilbert, R. Goldberg & T. Brown, The Impact of Decoupling on the Cost of Capital (Discussion Paper, The Brattle Group, March 2011), p. 2.

A. This would undercut the whole purpose of the mechanism, while introducing a whole new set of perverse incentives. It would reintroduce automatic penalties, in the form of reduced fixed-cost recovery, for all cost-effective electricity savings not directly associated with APS's programs, even when the Company by action or inaction could make a material difference in prospects for those savings. It would create a reason for the Company to promote programs that looked good on paper but delivered little or no savings in practice. And it would ensure adversarial discord over every savings calculation, since significant financial stakes would then hinge on the results. Finally, and most tellingly, adjustments keyed solely to adjudicated savings would mean automatic annual rate increases (unless the company was wholly ineffective), whereas decoupling adjustments can be either positive or negative (Southwest Gas notes as part of its own pending decoupling proposal, for example, that its most recent Nevada decoupling adjustment "will return approximately $2 million to its customers."[15])

Q. But doesn't your recommendation mean paying APS for savings that it didn't help achieve?

---

[15] In the Matter of Southwest Gas Corporation, Docket No. G-01551A-10-0458, Prepared Direct Testimony of Edward B. Gieseking, p. 9:5 (Nov. 12, 2010).

A. No, because the proposed EIA doesn't "pay" APS any incremental amount for anything; it is simply a mechanism that allows the company to receive no more and no less than the fixed-cost revenue requirement per customer that the Commission has reviewed and approved.

**SECTION X - The APS Proposal Reduces Risk to Customers**

Q. Revenue decoupling has been criticized as "use less, pay more" and shifting risk to customers; do you believe those are valid concerns regarding APS's proposal?

A. No. As indicated earlier in my testimony, customers who find ways to use significantly less energy will not be appreciably affected by decoupling-induced rate adjustments, and of course a principal justification for the Commission's Energy Efficiency Standards is to reduce the costs of providing reliable energy services, with long-term multi-billion dollar savings to APS customers (in the form of reductions in the company's revenue requirements and fuel purchases) that revenue decoupling will not affect. As regards risk shifting, an appealing feature of APS's proposal is that it reduces risks for *both* customers and the company; customers get relief from cost increases driven by extreme weather events, and APS avoids downside risk on recovery of its authorized fixed costs (although, as noted earlier, I do not view this as justification for a reduction in the company's ROE). Risk reduction is not a zero sum enterprise here.

**SECTION XI - Conclusion: Revenue Decoupling Removes a Powerful Disincentive for APS to Increase Its Energy Efficiency Investment**

Q. Does revenue decoupling remove the rationale for the Commission to provide energy-efficiency-related incentives for APS, in order to spur utility effort and achievement?

A. No. Revenue decoupling eliminates a potent disincentive for utility engagement in energy efficiency, but it does not supply an upside analogous to that accompanying utility-owned generation or grid assets. Meeting Arizona's appropriately aggressive energy efficiency targets requires more than institutional neutrality, and although it would certainly help to avoid automatic utility shareholder losses from cost-effective energy efficiency improvements, it would be even better to combine decoupling with shareholder rewards for utilities' success in delivering cost-effective savings. From the standpoint of motivating utility management and maximizing benefits to utility customers, my view is that both revenue decoupling and earnings opportunities are ultimately necessary and appropriate to ensuring that cost-effective energy efficiency remains a core element of the APS business model.

Q. Does this conclude your testimony?

A. Yes.

# Ernest Orlando Lawrence Berkeley National Laboratory

# Carrots and Sticks: A Comprehensive Business Model for the Successful Achievement of Energy Efficiency Resource Standards

Andrew Satchwell, Peter Cappers, and Charles Goldman

*Preprint version of paper for conference proceedings, ECEEE Summer Study, Giens, France, June 6-11, 2011*

Environmental Energy Technologies Division

**March 2011**

The work described in this report was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) - Permitting, Siting and Analysis Division under Contract No. DE-AC02-05CH11231.

## Disclaimer

## Acknowledgements

The work described in this report was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) - Permitting, Siting and Analysis Division under Contract No. DE-AC02-05CH11231.

The authors would like to thank Larry Mansueti (DOE OE) for his support of this project. The authors would also like to thank Jeff Schlegel for his comments and feedback on this paper.

LBNL-4399E

# Carrots and Sticks:
# A Comprehensive Business Model for the Successful Achievement of Energy Efficiency Resource Standards

Principal Authors

Andrew Satchwell, Peter Cappers, and Charles Goldman

March 2011

The work described in this report was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability (OE) - Permitting, Siting and Analysis Division under Contract No. DE-AC02-05CH11231.

## Table of Contents

## List of Figures and Tables

## Abstract

Energy efficiency resource standards (EERS) are a prominent strategy to potentially achieve rapid and aggressive energy savings goals in the U.S. As of December 2010, twenty-six U.S. states had some form of an EERS with savings goals applicable to energy efficiency (EE) programs paid for by utility customers. The European Union has initiated a similar type of savings goal, the Energy End-use Efficiency and Energy Services Directive, where it is being implemented in some countries through direct partnership with regulated electric utilities.

U.S. utilities face significant financial disincentives under traditional regulation which affects the interest of shareholders and managers in aggressively pursuing cost-effective energy efficiency. Regulators are considering some combination of mandated goals ("sticks") and alternative utility business model components ("carrots" such as performance incentives) to align the utility's business and financial interests with state and federal energy efficiency public policy goals. European countries that have directed their utilities to administer EE programs have generally relied on non-binding mandates and targets. In the U.S., most state regulators have increasingly viewed "carrots" as a necessary condition for successful achievement of energy efficiency goals and targets.

In this paper, we analyze the financial impacts of an EERS on a large electric utility in the State of Arizona using a pro-forma utility financial model, including impacts on utility earnings, customer bills and rates. We demonstrate how a viable business model can be designed to improve the business case while retaining sizable ratepayer benefits. Quantifying these concerns and identifying ways they can be addressed are crucial steps in gaining the support of major stakeholder groups - lessons that can apply to other countries looking to significantly increase savings targets that can be achieved from their own utility-administered EE programs.

## Common Acronyms and Definitions

- ACC *Arizona Corporation Commission* – Arizona state regulatory body with authority over public utilities, incorporation of businesses and organizations, securities regulation, and railroad/pipeline safety. The ACC is composed of five publicly elected Commissioners.
- APS *Arizona Public Service* – Arizona investor-owned utility that is the subject of this analysis.
- BAU *Business-As-Usual* – Used in this analysis as a scenario representing the pre-existing path of energy savings for a particular utility and assuming no new energy efficiency or demand response programs.
- DSM *Demand Side Management* – Strategies designed to encourage consumers to modify patterns of electricity usage, including reducing usage in many hours (i.e., energy efficiency) and reducing usage in peak periods (i.e., load management and demand response programs).
- EE *Energy Efficiency* – Programs intended to reduce the overall amount of energy used, while providing the same level of service to consumers.
- EERS *Energy Efficiency Resource Standard* – Molina et al. (2010) defines an EERS as "a quantitative, long-term energy savings target for utilities." Utilities may administer their own programs or use an authorized program administrator to achieve energy savings.
- EES *Energy Efficiency Standard* – The same long-term energy savings target as an EERS and implemented in some states, including Arizona.
- FERC *Federal Energy Regulatory Commission* – U.S. Federal regulatory agency with jurisdiction over interstate electricity sales and wholesale electric rates, among other things.
- O&M *Operations and Maintenance* – Category of utility costs pertaining to the ongoing maintenance of a utility power system which may be fixed or variable in nature.
- ROE *Return on Equity* – The level of earnings on utility equity determined by regulators in a utility rate case proceeding, expressed as a percentage. The utility may not exceed this established level (i.e., authorized ROE) and the utility often earns less than this authorized level as a function of declining sales due to energy savings or weather, regulatory lag, and/or business cycle fluctuations
- RPC *Revenue-Per-Customer* – A form of decoupling, whereby a utility's total revenues needed to provide safe, adequate, and reliable service are determined for a set amount of time and only allowed to change as the number of customers changes. This is the most common form of decoupling in the U.S.
- RPS *Renewable Portfolio Standard* – Regulation requiring a certain percentage of energy from renewable energy sources.

## 1. Introduction

U.S. regulators and legislators are utilizing energy savings goals in the form of energy efficiency resource standards (EERS) as a means to mandate aggressive energy efficiency (EE) savings (Barbose et al. 2009). As of December 2010, twenty-six U.S. states had some form of an EERS. Policy drivers for such mandates include offsetting potentially higher costs and environmental impacts associated with the construction of new generation resources and providing additional options for customers to control their energy costs. In the U.S., ratepayer-funded EE programs are a common means of delivering these savings.

U.S. utilities face significant financial disincentives under traditional regulation in pursuing aggressive energy efficiency goals which limits the interest of shareholders and managers. Both are concerned that the pursuit of aggressive EE savings will result in reduced utility revenues, affecting the utility's ability to fully recover its fixed costs and ultimately increasing the likelihood that the utility under-achieves its authorized return on equity (ROE), and limited opportunities to expand rate base thereby foregoing earnings-generating investments. Regulators and policymakers are considering or have adopted more comprehensive business models (e.g., shareholder incentives, and/or lost revenue recovery mechanisms) to align the utility's business and financial interests with a state's public policy goals for the electricity sector (e.g., increased efficiency, reduced emissions).

In establishing energy efficiency goals and targets, policymakers and legislators in both Europe and the U.S. can utilize varying combinations of "sticks" and "carrots". At one extreme is a "stick-only" approach, whereby utilities must meet mandated energy savings targets or face financial penalties. This approach is common in many U.S. states that have adopted a Renewable Portfolio Standards (RPS) with an alternative compliance payment provision if a utility does not achieve renewable energy goals. However, this "stick-only" approach (i.e., mandate with penalties) is much less common in the U.S. for energy efficiency.[1] As a practical matter though, because of financial disincentives, some/many U.S. utilities would characterize an energy savings mandate (i.e., EERS) absent the ability to recover fixed costs as a "sticks only" approach. In the U.S., utility energy efficiency programs have been most successful in those states that utilize a "sticks-and-carrots" approach, combining a mandated savings goal or target with a comprehensive business model.

This study examines (1) the customer bill and rate impacts, and (2) the shareholder earnings and return on equity (ROE) impacts when a utility achieves aggressive energy savings from an EERS. Our analysis will compare a "stick-only" approach of mandated energy savings goals to a "sticks-and-carrots" approach that includes a comprehensive business model. We model our analysis based on the Arizona Energy Efficiency Standard (EES), which directs Arizona investor-owned utilities to achieve 22% cumulative energy savings by 2020.[2] We provide a long-term assessment of impacts on ratepayers and shareholders from energy efficiency programs that achieve these savings reduction targets (about 2% per year) through 2020 with

[1] Pennsylvania is an example of a state with an EERS with a financial penalty provision and no ability for the utility to earn an incentive for successful achievement of energy efficiency targets or to recover lost revenues.
[2] Arizona Corporation Commission. *In the Matter of the Notice of Proposed Rulemaking on Electric Energy Efficiency.* Decision No. 71819. Docket No. RE-09-0427. August 10, 2010. An Energy Efficiency Standard (EES) is the same as an Energy Efficiency Resource Standard (EERS).

impacts over a 20-year time-horizon (2011-2030) to fully capture the benefits over the installed measures' useful lifetimes.

We characterize and model Arizona Public Service (APS), which is the largest investor-owned utility in Arizona, and analyze two EE portfolios: (1) a "business-as-usual" (BAU) EE scenario as if the EES was not enacted and APS continues on its pre-existing EE savings path of approximately 1% annual savings; and (2) an EES scenario as if APS meets the EES savings targets of about 2% annual savings.[3] We examine issues from a customer perspective – impacts of the EES on aggregate customer bills and rates compared to the "business as usual" case. We also analyze issues from the perspective of utility shareholders and managers and assess the effects on earnings and ROE of the EES compared to the "business as usual" case with and without a comprehensive business model (e.g., a revenue-per-customer decoupling mechanism and a shareholder incentive mechanism).

The remainder of the paper describes the comprehensive business model, discusses the study approach (including the utility financial characterization, EE portfolios, and ratepayer and shareholder impact scenarios), presents analysis results, and concludes with key findings and policy discussion.

[3] The specific provisions of the Arizona EES allow utilities to take some credit for energy efficiency measures installed prior to 2011 (starting in 2016), demand response programs, and the effects of improved building codes as part of complying with their savings target.

## 2. Comprehensive Business Model

The traditional electric utility business model in the U.S. provides a financial incentive for increasing electricity sales and making investment in supply-side generation. Regulators in the U.S. establish a utility's tariff (i.e., rates), based on forecasted sales and its existing and forecasted costs, including a return on investment, in a rate case proceeding. Once rates are established, the utility may improve its financial performance between rate cases by either increasing sales above those forecasted and/or managing its costs. This financial incentive comes in the form of increased revenues and/or lower costs, respectively, and hence larger profits (if revenues grow faster than costs), as well as a guaranteed return on supply-side investments that are utilized to serve increasing demand.

Conversely, a utility may experience financial harm when sales decrease between rate cases. Because a utility's revenues are a function of the regulated price for energy and its sales to customers, any downward change in sales from the forecasted level results in reduced utility revenues. The pursuit of energy savings exists then as a disincentive to the investor-owned utility as it directly impacts and reduces the utility's collected revenue and hence profitability between rate cases (again if revenue reductions outpace cost savings) through decreased sales while deferring investment in supply-side generation. Despite the clear benefits of EE to ratepayers and society as a whole, there is a bias among U.S. investor-owned utilities against the pursuit of energy savings.

The traditional utility business model is further challenged by regulatory or legislative energy savings mandates (e.g., EERS), which alone may function as a "stick" for the utility. A regulated utility prefers a viable business model when faced with energy savings mandates; a viable business model encourages or incents the utility to capture the societal benefits of energy efficiency, delivering benefits to customers, while ensuring that profitability can in fact come from EE investment.

There are three components of a comprehensive EE business model, from the utility perspective: recovery of prudently-incurred program costs, collection of lost revenues associated with EE savings (the portion of lost revenues that would be used to recover authorized fixed costs), and the development of a shareholder incentive. If a regulator approves only a subset of the three components, the effectiveness of any component may be undermined (Hayes et al. 2011).

1. Ensure cost recovery. The recovery of program costs is intended to allow the utility to fully offset the costs of implementing and administering EE programs. In the U.S., when energy efficiency programs were first offered by utilities in the late 1980s and 1990s, a few utilities were unable to recover all of their costs for administering EE programs in subsequent regulatory proceedings because cost recovery mechanisms were not in place. Since then, utilities request and regulatory authorities often provide guidance on the cost recovery mechanism that utilities can use to recover program costs associated with administering energy efficiency programs. In many cases, regulatory authorities allow and authorize utilities to expense their program costs incurred in situations where the regulatory authority has reviewed and approved an EE plan; this approach is designed to mitigate the risk that the utility will not fully recover prudently incurred EE program expenses in a timely fashion.

2. Reduce the disincentive. The utility must have sufficient revenues to cover its system costs. A utility's past investments in their generation, transmission, and distribution systems are recovered through current and, to some degree, future retail rates based on a forecast of energy sales, among other things. As discussed earlier, any decrease in forecasted sales between rate cases because of energy savings from energy efficiency programs may result in a reduction in utility revenues. Regulators may approve the collection of those revenues lost to the decline in sales in order to insulate the company from not being able to recover its fixed, non-fuel costs, thereby making the utility "financially indifferent" to a change in sales from EE. Decoupling is a common form of lost revenue recovery mechanism and is designed to remove the link between sales and revenues by establishing a determined amount of revenues the utility may collect for a set period of time, regardless of sales levels.

3. Provide a shareholder incentive. The intent of a shareholder incentive is to provide a utility with an opportunity for additional earnings if it is successful in achieving aggressive savings goals and to make energy efficiency a potential business "profit center" for the utility. Supply-side investments are often much larger than dollars spent on EE and utilities can account for the investment in its ratebase, or value of utility property, and earn a return on the investment. This presents a potential bias towards such investments, as utilities may find the supply-side investment more attractive when compared to energy efficiency investments that typically are not part of ratebase. If a utility does not receive regulatory approval to implement a shareholder incentive but has a pre-existing incentive to make investments in supply-side generation, the utility will tend to prefer supply-side investments that provide greater earnings opportunities.

Shareholder incentives and lost revenue recovery mechanisms have seen increased attention in recent years at the federal and state levels. The American Recovery and Reinvestment Act of 2009 (ARRA), passed in February 2009, included additional state energy grant opportunities if the state regulator has sought to implement a policy that aligns financial incentives for electric utilities. At the state-level, 31 states have enacted some sort of lost revenue recovery and/or shareholder incentive mechanism. Of those states who lead the U.S. in energy efficiency program spending, eight of the top ten have implemented a combined shareholder incentive and lost revenue recovery mechanism (Molina et al 2010).

## 3. Approach

We used a pro-forma, spreadsheet-based financial model adapted from a tool (Benefits Calculator) constructed to support the National Action Plan for Energy Efficiency (Cappers et al. 2009a). This model builds on previous LBNL work on shareholder incentives (Cappers et al. 2009b, 2009c, 2010) by characterizing the effects of an EERS. The major steps in our analysis are depicted in Figure 1.

The first step is to identify the main inputs ("Model Inputs"): (1) a characterization of the utility which includes its initial financial and physical market position, a forecast of the utility's future sales, peak demand, and resource strategy and estimated costs to meet projected growth; and (2) a characterization of the demand side management (DSM) portfolio – projected electricity and demand savings, costs and useful lifetime of a portfolio of energy efficiency and demand response programs that the utility is planning or considering implementing during the analysis period.

The second step is to identify the scenarios of interest for the analysis ("Scenario Analysis"). These scenarios include a base case that maintains the current portfolio of DSM programs ("Business-As-Usual (BAU)") as well as alternative scenarios that include different energy efficiency and demand response resource savings levels and alternative business models ("With DSM").

The third step is to define the characteristics of the DSM business model of interest ("DSM Business Model"), determining what components will be included (e.g., DSM program cost recovery, lost fixed cost recovery and/or shareholder incentives).

The model provides outputs in the form of common stakeholder metrics ("Model Outputs"): (1) shareholder metrics include ROE and total earnings; and (2) ratepayer metrics include estimated retail rates and total customer bills for each year of the study period. Model outputs from various scenarios that differ by the level of achieved DSM savings and costs, application of alternative DSM business models, etc. can be compared to assess changes in utility earnings, ROE, average retail rates, and customer bills. The Benefits Calculator model also estimates total DSM resource costs and benefits of the DSM portfolio ("DSM Resource Costs & Benefits") using a forecast of avoided capacity and energy costs.

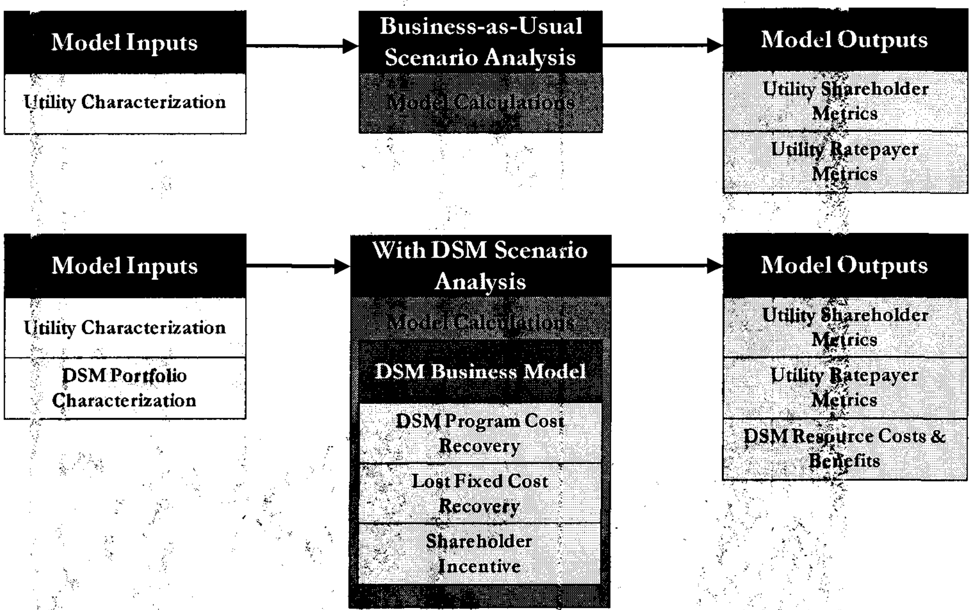



*Figure 1. Flowchart for analyzing impacts of portfolio of energy efficiency programs on stakeholders*

## 4. Modeling Characteristics

### *4.1 Utility Characterization*

We developed a long-range cost and load forecast for APS (2011 to 2030), using historic information from the US Federal Energy Regulatory Commission (FERC) Form 1 as well as the utility's most recent general rate case data. This information was used to construct an expected relationship between growth in peak demand and growth in costs, which was reviewed by APS staff and served as the basis for our analysis.

In 2011, APS has retail sales of ~30,000 GWh and a peak demand of ~6,470 MW, which are forecasted to grow at a compound annual rate of 2.9% and 3.1% per year, respectively over a 20-year time horizon (excluding energy efficiency programs). The utility has ~1.1 million customers in 2011 and expects significant customer account growth of 2.7% per year. With such fast growing electricity requirements, the utility projects that its non-fuel expenses, inclusive of return of and on capital expenditures and operations and maintenance (O&M) expenses associated with new generation assets will increase in excess of 5% per year. Increases in non-fuel expenses are reflected in retail rates after the Arizona Corporation Commission (ACC) has issued an order in a general rate case or other regulatory filing.[4] However, revenue growth between rate cases is not anticipated to keep pace with the ~5% annual growth in non-fuel expenses.[5] Thus, APS would be unable to achieve its authorized ROE of 11%. This is a case of significant utility under-earning prior to the achievement of aggressive EE savings. Without a decoupling mechanism to mitigate the revenue erosion between rate cases, we assume that the utility would file a rate case triennially (i.e., every third year) to reduce the detrimental impact on shareholder returns.[6]

### *4.2 Demand Side Management (DSM) Portfolio Characterization*

In 2008, Arizona's utilities achieved electricity savings of ~0.53% of retail sales, which places Arizona near the national average among U.S. utilities in pursuing energy efficiency (Molina et al. 2010). However, in 2010, the state's policymakers established energy savings goals that are among the most ambitious in the United States. The Arizona EES was established by ACC rulemaking in July 2010 requiring electric utilities to achieve 22% cumulative savings in 2020.[7] Under the EES, annual savings targets are set at 1.25% in 2011 and accelerate to 2.5% per year in 2016-2020.[8] We have constructed two EE portfolios that capture the pre-existing level of energy efficiency activity and savings (i.e., BAU with EE) and a second scenario that includes the required energy efficiency program savings goals under the new EES (see Figure 2).

The first energy efficiency portfolio represents a BAU with EE case as if Arizona had not passed the EES but simply continued on its pre-existing path of capturing energy efficiency savings of

---

[4] Fuel and purchased power costs are passed through to APS customers annually through a fuel adjustment clause (FAC) and so are modeled as if they are completely collected in the year they are incurred.

[5] APS receives additional base revenues as the number of customer accounts increase each year (2.7% per year) and/or as customers increase their electricity usage; although revenues from retail rates increase at a slower rate than expected non-fuel costs.

[6] APS is assumed to use a historic test year in their rate case filings. Generally there is a two-year lag between the time a general rate case is filed and the time the ACC issues an order setting retail rates.

[7] Arizona Corporation Commission. In the Matter of the Notice of Proposed Rulemaking on Electric Energy Efficiency. Decision No. 71819. Docket No. RE-09-0427. August 10, 2010.

[8] There are several provisions in the regulation that allow credits for pre-standard energy savings beginning in 2016, a credit for improvements in building codes, and a credit for demand response savings.

~1% annually on a nominal 2010 budget of $43M.[9] In this scenario, the utility achieves 43,581 GWh of electricity savings over the 2011-2030 period,[10] which provides ~$946M[11] in net resource benefits between 2011 and 2030 (see Table 1).[12] Program administration and measure costs are assumed to grow at a nominal annual rate of 4.3% for residential EE programs and 4.8% for non-residential programs.

The EES portfolio represents savings and expenditure levels based on utility compliance with the Arizona EES. Under this aggressive scenario, cumulative annual electricity savings exceed 7,000 GWh in the year 2020 when accounting for EES requirements and credits (see Figure 3). The utility achieves 95,002 GWh of electricity savings over the 2011-2030 period. The EES portfolio has a total resource cost of ~$2.2B and produces $3.6B in resource benefits, thus providing $1.4B in net resource benefits (see Table 1).

We constructed the portfolios based on typical program costs to achieve the established savings levels. In the BAU with EE portfolio, average EE costs were estimated at ~1.9 cents/lifetime-kWh. Given the increase in savings levels in the EES portfolio, we estimated that average EE costs would increase to ~2.8 cents/lifetime-kWh.[13] The costs associated with the EES portfolio is quite attractive compared to supply-side alternatives. In both portfolios, 50% of electric savings comes from residential programs in 2011 and the share decreases as we assume more savings will have to come from commercial and industrial EE programs over time. In Arizona, savings from residential lighting programs are projected to decrease due in large part to federal lighting standards set to change in 2012.[14]

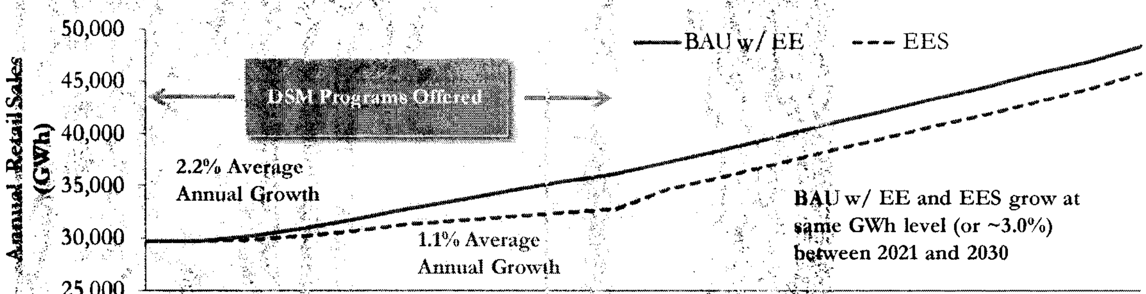



*Figure 2. Effect of energy efficiency portfolios on Arizona utility load forecast*

[9] APS had an existing level of EE savings determined as part of a settlement agreement in its most recent rate case, which established an annual savings goal of 1.0%, 1.25%, and 1.5% in 2010, 2011, and 2012, respectively. We assumed APS returned to 1.0% annual savings level in 2013-2020.
[10] A decision was made to implement energy efficiency programs for a ten year period (2011-2020) but allow the analysis period to extend out twenty years (2011-2030). This was done so the benefits derived from expenditures on energy efficiency measures implemented could be fully captured in the model time horizon.
[11] All dollar figures are reported on a present value basis using a societal discount rate of 4.0%.
[12] In the calculation of resource benefits, we include the avoided cost of energy, avoided cost of generation capacity, and avoided cost of T&D capacity and exclude non-electric benefits (e.g., water savings, avoided alternative fuel savings). We also do not include the shareholder incentive or the lost fixed cost recovery mechanism in estimating resource costs.
[13] The estimated program cost per lifetime kWh saved is averaged over the 2011-2020 period. EE program costs increase from ~1.5 cents/lifetime-kWh in 2011 to 4.0 cents/lifetime-kWh in 2020.
[14] Our EE portfolio savings and costs were reviewed and vetted by APS and are consistent with the utility's typical program offerings.

**Table 1. Lifetime savings, resource costs and benefits of alternative energy efficiency portfolios (2011-2020)**

| | Portfolio Lifetime Savings | | | | Total Resource ($M, PV) | | |
|---|---|---|---|---|---|---|---|
| Case | Peak Energy (GWH) | Off-Peak Energy (GWh) | Total Energy (GWh) | Peak Demand (MW) | Benefits | Costs | Net Benefits |
| BAU w/ EE | 30,507 | 13,074 | 43,581 | 602 | 1,675 | 729 | 946 |
| EES | 75,664 | 19,338 | 95,002 | 1,520 | 3,616 | 2,208 | 1,408 |

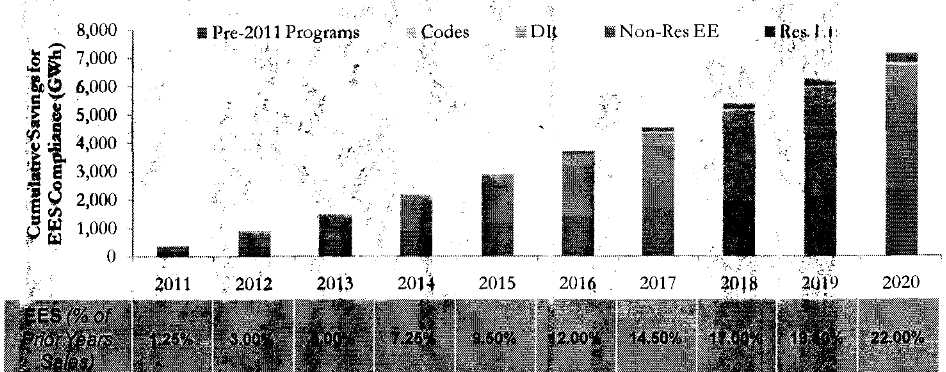



*Figure 3. Cumulative savings from Energy Efficiency Standard for Arizona Public Service Company*

### *4.3 Business Model Construction*

Arizona has historically allowed the recovery of prudently incurred EE program costs, and thus, we modeled program costs as a component of the utility revenue requirement. The ACC has also previously approved a shareholder incentive for APS for the successful achievement of target EE savings. The incentive is capped at 14% of program costs, on a pre-tax basis. We modeled the shareholder incentive at the approved amount and assumed the utility would achieve 100% of its targeted energy savings. We included both the program cost recovery and shareholder incentive business model components in the initial analysis of the BAU with EE and EES portfolios. Given the magnitude of the mandated energy efficiency savings in Arizona, revenue erosion will likely become a major concern for utilities in the achievement of the EES. At the time of our analysis, the ACC was considering allowing utilities to implement a decoupling mechanism to support recovery of authorized fixed costs.

Based on conversations with the ACC, we decided to apply a revenue-per-customer (RPC) decoupling mechanism. An RPC decoupling mechanism is designed to recover the utility's required revenues on a per-customer basis. The decoupling mechanism was applied only in the EES case to make the utility financially indifferent between the pursuit of the EES goals or lack thereof (relative to the BAU with EE).[15] When coupled with a shareholder incentive mechanism, this comprehensive business model may provide an opportunity for the utility to realize additional earnings and/or a higher ROE from the successful achievement of the aggressive energy efficiency savings goals.

[15] We did not include a decoupling or lost revenue recovery mechanism in the BAU with EE case based on discussions with ACC and Arizona utilities.

## 5. Analysis Results

We assess the impacts of implementing an EES portfolio on customers' bills and rates and on utility earnings and ROE compared to a "business as usual" case that includes current energy efficiency programs (BAU with EE). We then focused on developing a more robust EE business model by applying a RPC decoupling mechanism when the utility achieves the EES savings goals to assess the degree to which it will improve the financial outlook for shareholders and at what cost to ratepayers.

The EES portfolio provides substantial ratepayer bill savings at relatively modest rate increases.[16] If APS achieves the savings targets in the EES, then ratepayers would realize about $4.6B of customer bill savings between 2011 and 2030 (see Figure 4). These incremental bill savings are in addition to the bill savings that customers realize from participating in the existing energy efficiency programs offered by the utility in the BAU case (~$4.3B) and are also net of the costs of energy efficiency programs (e.g. costs of administering the program, incentives to customers). It is important to note that ratepayers, as a whole, begin to see bill savings starting in 2016 as new generation plants begin to be deferred and fuel costs are reduced (see Figure 4). This trend in aggregate bill savings occurs for two reasons. First, the utility cost savings associated with these energy efficiency portfolios (e.g. reduced fuel costs and lower capital and O&M requirements for new generation) take time to develop and inure to ratepayers (based on the timing of general rate case filings) sufficient to offset the annual EE program expenditures. Second, the costs of the energy efficiency programs are expensed during each program year, while the energy savings and other benefits accrue over the lifetimes of the measures.[17] Thus, in this situation, a short-term analysis might not full y capture the bill reductions that would occur over time and inure to consumers as a whole, depending upon the time horizon chosen.

Customer rate impacts from energy efficiency increase as savings levels rise. This is primarily a function of the decline in sales being higher than the reduction in revenue requirement from the achieved EE savings.[18] In the EES portfolio, annual rates are ~1.0 cents/kWh higher, on average, than in the BAU with EE portfolio (see Figure 5). There is an observed increase in retail rates while DSM programs are being offered (2011-2020) and a decrease in retail rates when DSM programs costs are no longer incurred and the savings from EE accrue to ratepayers.

[16] The Benefits Calculator model used to perform this analysis only provides aggregate ratepayer effects; thus rate and bill impacts can not be broken out separately for participants in the EE program or non-participating customers.

[17] Bill savings also increase after 2020 because DSM program costs are no longer incurred while savings from measures installed continue to yield savings over their economic lifetime (assumed to be 10 years for the entire portfolio of measures) and reduce customer bills.

[18] All-in retail rates are a function of the utility's revenue requirement in the numerator and sales in the denominator. Mathematically, a unit decrease in the numerator will decrease the fraction while a unit decrease in the denominator will increase the fraction, ceteris paribus. In this case, both the numerator and denominator are being reduced. In percentage terms, electricity sales (denominator) are dropping much faster than the revenue requirement (numerator), so retail rates (the fraction) will increase.

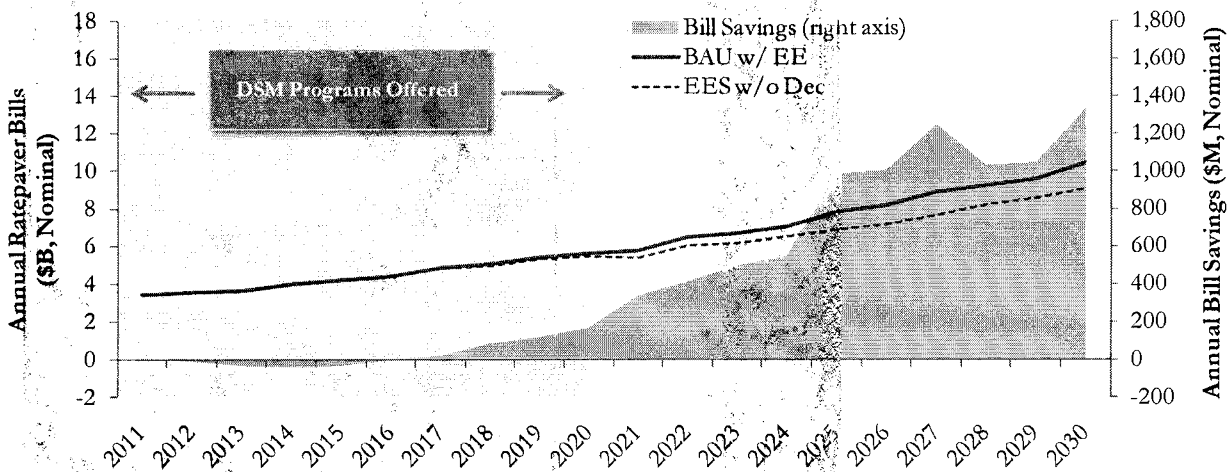



*Figure 4. Ratepayer bills and bill savings of Arizona Public Service Company customers*

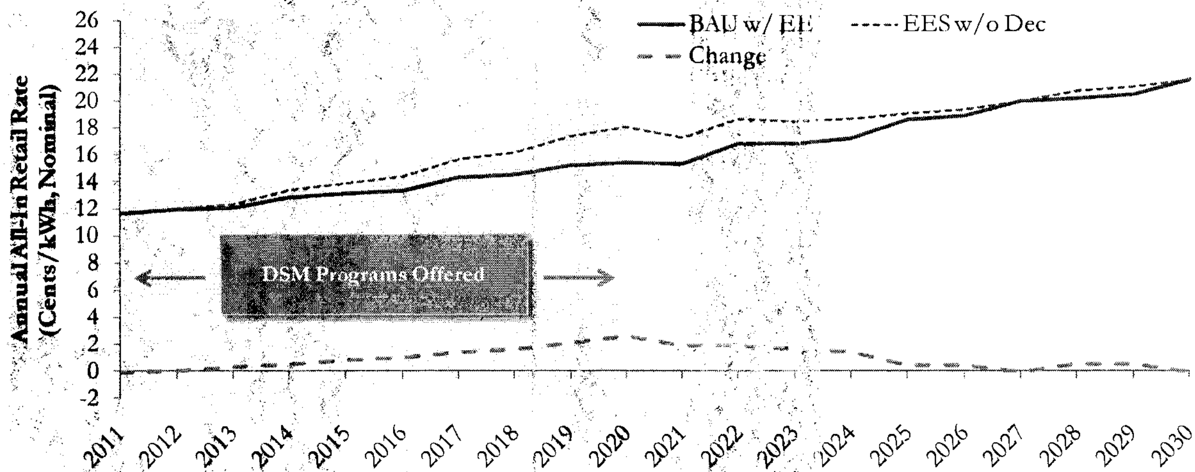



*Figure 5. Impact of EES portfolio on all-in retail rates of Arizona Public Service Company customers*

If the regulators adopt a "stick-only" approach, they would establish energy savings goals that the utility must achieve and only provide for recovery of energy efficiency program costs. The utility's base earnings for each scenario in Figure 6 and Figure 7 reflect this "stick only" approach in which the utility is only allowed to recover the costs of energy efficiency programs, but is not allowed to recover "lost revenues" associated with energy efficiency or provided an opportunity for additional earnings due to achieving energy efficiency savings targets (i.e. a case without a comprehensive business model). In the "business as usual" case (that includes the current level of energy efficiency programs), utility base earnings are about $2.52B between 2010 and 2030 (see Figure 6). In the EES scenario, the utility achieves base earnings of $2.23B, which is ~$290M lower than the BAU with EE case. This illustrates the point that a utility that achieves aggressive EES goals will end up with lower earnings compared to a BAU case. A similar trend is observed with respect to the impacts on the utility's return on equity (ROE). The achieved ROE for APS is much lower (~7%) than its authorized ROE (11%); APS is under-earning the authorized ROE by ~400 basis points based on our analysis.[19] The utility is experiencing significant under-earnings as a result of the lag in years between when a request for rate change is filed with regulators and when the regulators approve the rate increase (i.e., regulatory lag), as well as non-fuel costs are increasing at a faster rate than revenue collections. In addition to these pre-existing impacts on utility earnings, aggressive EES goals exacerbate the impact on the utility's ROE in the absence of a comprehensive business model. The utility's base ROE is 75 basis points lower if it achieves the EES savings goals compared to the BAU case, 6.73% vs. 7.48% (see Figure 7).

Utility shareholders are concerned about the impact of aggressive EE programs on their earnings and ROE, especially considering the degree to which the utility is already under-earning relative to authorized levels. We consider a "stick-and-carrots" approach by implementing a comprehensive business model to address shareholder concerns. Under the EES portfolio, the utility's returns are reduced even further, by 75 basis points and \$290M in earnings, but the shareholder incentive mechanism only adds back 34 basis points and \$110M in earnings. Without the introduction of some sort of decoupling or lost revenue recovery mechanism as part of a more comprehensive utility EE business model, it is unlikely the utility would voluntarily attempt to achieve the EES savings goals.

The implementation of an RPC decoupling mechanism, designed as part of a comprehensive business model for the achievement of the EES, would allow the utility to achieve nearly comparable shareholder returns to the BAU with EE case. The decoupling mechanism would increase earnings by ~\$150M and ROE by 45 basis points, which is a more lucrative component of the comprehensive business model than the performance incentive.

The incremental cost of the RPC decoupling mechanism to ratepayers would be ~\$320M, or a 0.9% increase in customer bills, between 2011 and 2020, and would raise all-in retail rates on average by ~1.5 mills/kWh (or 1.0%). Even with this additional recovery by the utility, ratepayers as a whole would still realize significant incremental bill savings under the EES portfolio of \$4.6B in aggregate.

[19] Basis points are used to denote the change in a financial metric. For example, a 100 basis points drop in ROE is equal to a 1% reduction in return on equity.

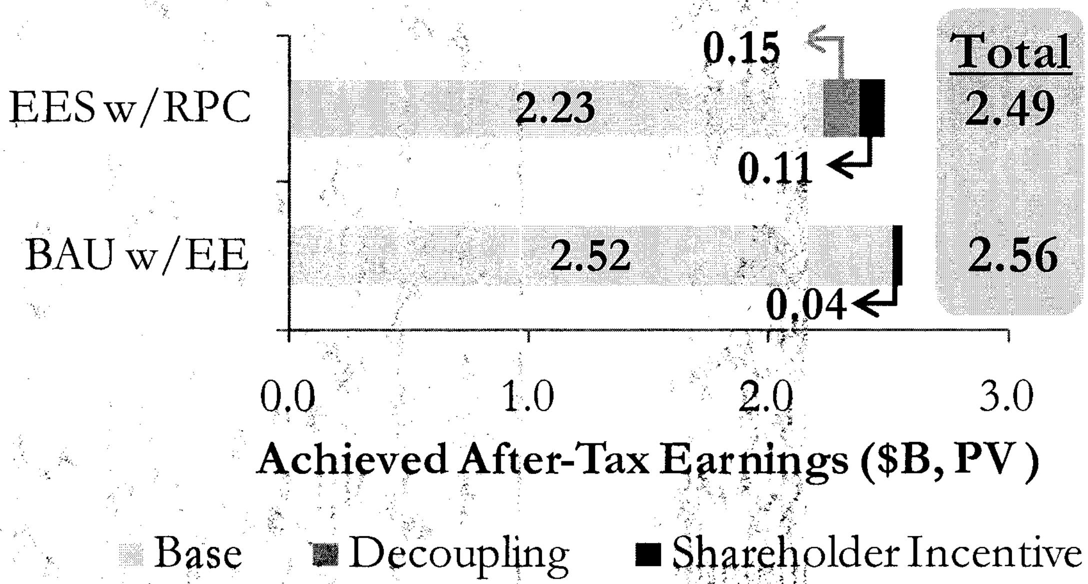



*Figure 6. Impact of a comprehensive energy efficiency business model on utility earnings*

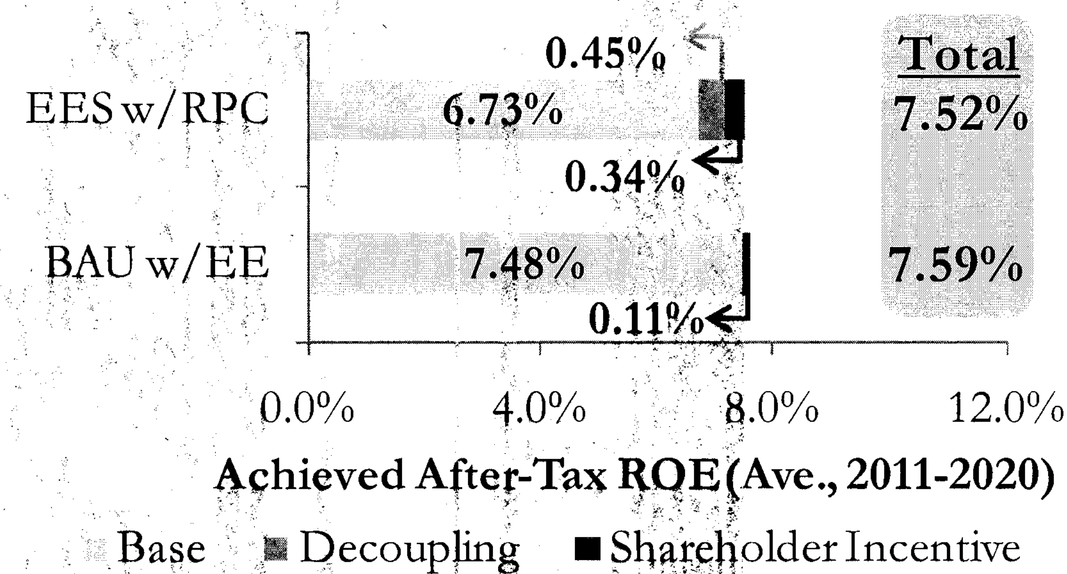



*Figure 7. Impact of a comprehensive energy efficiency business model on utility ROE*

## 6. Conclusion

This analysis quantifies the impacts on ratepayers and shareholders when a state like Arizona mandates aggressive energy efficiency goals: ~2.0% savings as percent of annual retail sales through ratepayer-funded programs offered by its electric utilities. We focus on the ability of a comprehensive business model, including program cost recovery, decoupling to support fixed cost recovery, and a shareholder incentive, to align the interests of utility shareholders and managers with the state's public policy goals (i.e., achieving aggressive EE savings targets).

The portfolio of energy efficiency programs included in the EES is an attractive, relatively low-cost resource for Arizona utility customers. We estimate that the portfolio of EE programs that meets EES goals would provide ~$1.4B in net resource benefits over the analysis period (2011-2030). Customer bills would be about $4.6B lower (or 5.9%) over the lifetime of installed measures (2011-2030) compared to the "business as usual" case that includes the pre-existing path of EE savings.[20] These bill savings account for and are net of any rate increases necessary to fund the increased energy efficiency efforts. Rates are modestly increased by ~1.0 cents/kWh higher, on average, than in the pre-existing case.

Our analysis also suggests that the utility faces significant erosion in earnings and a lower ROE as more aggressive energy efficiency programs are implemented. Without the effect of an RPC decoupling mechanism, utility earnings are ~$220M lower under the EES scenario compared to the BAU with EE scenario. Our analysis, however, shows that it is possible to design an RPC decoupling mechanism that allows the utility to effectively remove the impacts on the utility's achieved ROE from the lower sales and thus reduced recovery of fixed costs. With the implementation of an RPC decoupling mechanism designed in this fashion along with a shareholder incentive that provides the Arizona utility with 14% of program costs on a pre-tax basis, shareholder returns (i.e., ROE) would be comparable to the BAU with EE scenario. The implementation of this type of decoupling mechanism would only slightly increase average all-in retail rates by ~1.0%.

This study provides some insights for policymakers and regulators interested in pursuing aggressive EE goals. While this analysis was specific to a U.S. regulatory context, utilities that operate under a similar regulatory structure in which earnings (and the utility's profitability) increases as energy sales increase would have a bias against energy efficiency (because of the impact of energy savings on revenues from sales). As nations around the world begin to consider and/or mandate aggressive EE policy goals, it becomes vitally important for policymakers to consider comprehensive business models in order to mitigate potential utility financial impacts. Our case study of a large Arizona utility suggests that an aggressive EE portfolio can provide significant benefits to ratepayers and also demonstrates that regulators, utilities, and other stakeholders can align the financial interests of utilities with broader governmental energy policy goals.[21]

[20] Net resource benefits are a metric of societal benefits from the DSM portfolio. The BC model calculates net resource benefits as the administratively determined avoided energy and avoided capacity benefits minus the utility program costs and installed costs of the energy efficiency measures. Customer bill savings are a metric for the impact on customers when a utility achieves aggressive energy savings. The BC model calculates customer bill savings as the actual benefits of avoided energy and capacity expenditures net of any rate increases to customers to pay for the increased energy efficiency.

[21] The ACC unanimously approved a decoupling policy statement on December 15, 2010 establishing guidelines for an electric utility's decoupling mechanism based in large part on the results of this analysis. See ACC Docket No. E-J-08-0314.

We presented a comprehensive business model to achieve aggressive energy savings that assumes that utilities administer energy efficiency programs funded by their customers. It is important to note that a number of U.S. states, and other countries, have chosen other types of entities and organizations besides utilities to administer ratepayer-funded energy efficiency programs. There are two other types of administrative models that have emerged. First, some states have chosen an existing state agency to act as the program administrator (e.g., New York Energy Research and Development Authority) or have created a new agency or non-profit corporation (e.g., Energy Trust of Oregon). In these states, the state agency administering the energy efficiency programs has signed a Memorandum of Understanding (MOU) with the state regulatory commission which establishes a multi-year contract and performance period. If the state agency fails to effectively administer and deliver ratepayer-funded EE programs, the regulatory commission has the option of terminating and/or not renewing the MOU with the state agency. Second, other states have selected and signed multi-year contracts with third-parties, either non-profit or for-profit companies, that have been selected through competitive solicitations to administer ratepayer-funded EE programs. In the states that have utilized this approach (e.g., Vermont, Hawaii, Wisconsin, New Jersey), the third party program administrator typically has the opportunity to earn a performance incentive included as part of their contract (typically at levels that are between 1-4% of program costs) for successfully meeting program goals or targets It should be noted, however, that non-utility administration does not address the financial impacts of energy efficiency on the utility from declining sales and it fails to fully address the supply-side investment incentives obstructing energy efficiency policy objectives.[22] It is vital, therefore, that a successful business model for energy efficiency must take into account and balance the interests of all stakeholders.

[22] Cappers et al. (2009a) discussed the conceptual framework of the energy efficiency business model in further detail.

## References

Barbose, G., C. Goldman, and J. Schlegel, 2009. "The Shifting Landscape of Ratepayer Funded Energy Efficiency in the U.S." *The Electricity Journal* 22(8):29-44.

Cappers, P., C. Goldman, M. Chait, G. Edgar, J. Schlegel, and W. Shirley, 2009a. "Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility." LBNL-1598E. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Cappers, P. and C. Goldman, 2009b. "Empirical Assessment of Shareholder Incentive Mechanisms Designs under Aggressive Savings Goals: Case Study of a Kansas "Super-Utility"." LBNL-2492E. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Cappers, P. and C. Goldman, 2009c. "Financial Impact of Energy Efficiency Under a Federal Renewable Electricity Standard: Case Study of a Kansas "Super-Utility"" LBNL-2924E. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Cappers, P., A. Satchwell, C. Goldman, and J. Schlegel, 2010. "Benefits and Costs of Aggressive Energy Efficiency Programs and the Impacts of Alternative Sources of Funding: Case Study of Massachusetts." LBNL-3833E. Berkeley, Calif.: Lawrence Berkeley National Laboratory.

Hayes, S., S. Nadal, M. Kushler, and D. York, 2011. "Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency." *ACEEE* U111. Washington, D.C.: American Council for an Energy-Efficient Economy.

Molina, M., M. Neubauer, M. Sciortino, S. Nowak, S. Vaidyanathan, N. Kaufman, and A. Chittum, 2010. "The 2010 State Energy Efficiency Scorecard." *ACEEE* E107. Washington, D.C.: American Council for an Energy-Efficient Economy.

Jensen, V., 2007. "Aligning Utility Incentives with Investment in Energy Efficiency: A Product of the National Action Plan for Energy Efficiency." Fairfax, Va.: ICF International, Inc.

EXHIBIT
NRDC-2
ADMITTED

Laura E. Sanchez
NATURAL RESOURCES
DEFENSE COUNCIL
PO Box 65623
Albuquerque, NM 87193
(505) 352-7408
lsanchez@nrdc.org

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

GARY PIERCE – Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

| | |
|---|---|
| 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-11-0224<br><br>**NRDC's NOTICE OF TESTIMONY IN PARTIAL OPPOSITION TO THE PROPOSED SETTLEMENT** |

Natural Resources Defense Council ("NRDC") by and through its attorney hereby files the attached Testimony of its Witness Ralph Cavanagh in Partial Opposition to the Proposed Settlement Agreement in the above-referenced matter.

RESPECTFULLY SUBMITTED this 17th day of January, 2012.

By Laura E. Sanchez

Laura E. Sanchez
NRDC
PO Box 65623
Albuquerque, NM 87193

ORIGINAL and 13 COPIES of the foregoing filed this 17th day of January, 2012 to:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing electronically mailed this 17th day of January, 2012 to:

All Parties of Record

By: ____________

## TABLE OF CONTENTS

BEFORE THE ARIZONA CORPORATION COMMISSION

TESTIMONY OF RALPH CAVANAGH

IN PARTIAL OPPOSITION TO THE

PROPOSED SETTLEMENT AGREEMENT

## I. INTRODUCTION

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

A. My name is Ralph Cavanagh. My business address is c/o NRDC, 111 Sutter Street, San Francisco, CA 94014. I am the Energy Program Co-Director for NRDC.

Q. Did you submit direct testimony in this proceeding?

A. Yes, I filed testimony on behalf of the Natural Resources Defense Council in support of the Arizona Public Service Company's proposal for full revenue decoupling.

Q. Have there been any changes in your qualifications?

A. No.

## II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony in partial opposition to the proposed Settlement Agreement.

A. Barely a month after its decision in the Southwest Gas rate case, the Commission faces a virtually identical choice on the issue of whether to decouple a utility's financial health from increases in its retail energy sales. My direct testimony urged the Commission to approve the Arizona Public Service Company's (APS) proposal for an Efficiency and Infrastructure Account ("EIA"), which represented a straightforward decoupling mechanism of the very type endorsed in the Final Policy Statement adopted unanimously by the Commission less than a year earlier.[1] After the filing of my testimony, the Commission approved (on December 13, 2011) full revenue decoupling for the Southwest Gas Company, based on a settlement proposal that left the Commission a clear choice between full decoupling and a lost revenue recovery mechanism. The Commission's decision in favor of decoupling included a thorough review of policy and legal issues, and signaled no retreat from the Final Policy Statement. That same document is cited repeatedly in my direct testimony as the primary basis for NRDC's support of APS's revenue decoupling proposal in this proceeding.

In this proceeding, as in the Southwest Gas case, NRDC and SWEEP are urging the Commission to adopt full decoupling, while Staff and others are contending that the Commission should adopt a clearly inferior alternative in the form of a lost fixed-cost recovery mechanism. The only relevant difference between the two proceedings is that the Southwest Gas case framed the choice as part of a proposed Settlement Agreement (which NRDC joined), whereas in this

---

[1] Arizona Corporation Commission, Final Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314 (December 29, 2010) ("Final Policy Statement").

case the proposed Settlement Agreement attempts to prevent the Commission from making the same choice, by including only the inferior alternative in the body of the Agreement. For that reason, NRDC did not join the proposed Settlement Agreement. I recommend that the Commission decide this case in the same way it resolved the Southwest Gas case: approve the Settlement Agreement, but substitute decoupling (in the form of the original APS proposal) for lost fixed-cost recovery. My testimony primarily addresses that issue, although I support also the additional recommendations in Jeff Schlegel's testimony for SWEEP.

Prior to the filing of the Settlement Agreement, the principal opposition to the APS proposal for revenue decoupling came in testimony by Staff, AARP and RUCO. Staff championed the lost fixed cost recovery mechanism that became part of the proposed Settlement Agreement. AARP's witness, Nancy Brockway, essentially ignored the Commission's Final Policy Statement and (like the RUCO witness) tried to relitigate issues that the Statement addressed fully. This might be relevant if the Commission had acted to reopen these issues, but it has not done so. RUCO's witness said that he is "not unalterably opposed to decoupling,"[2] although he went on to oppose it on terms strikingly similar to those used unsuccessfully by RUCO in contesting the Commission's recent adoption of decoupling for Southwest Gas, including advocacy for a straight fixed variable rate design policy that would reduce customers' rewards for saving energy (Walmart Stores expressed a similar preference in the Testimony of Steve W. Chriss).

The testimony of these witnesses has an almost generic quality; the arguments could be and no doubt have been used in many other states to oppose revenue decoupling and support straight fixed-variable rate design. But as an invited and active participant in the 2010 workshops that preceded the Commission's Final Policy Statement, I believe that in Arizona, witnesses need at minimum to acknowledge and accommodate the Commission's analysis and conclusions. Opponents of decoupling in this case have conspicuously failed to do so.

## III. THE PROPOSED SETTLEMENT AGREEMENT

Q. The proposed Settlement Agreement essentially substitutes Staff's proposal for lost fixed-cost recovery (LFCR) for the APS decoupling proposal. Why isn't lost

[2] Additional Direct Testimony of Frank W. Radigan (Nov. 23, 2011), p. 12: 18-19.

fixed-cost recovery a reasonable alternative to full decoupling?

A. Without repeating the list of reasons in my direct testimony (see pp. 12-13), I emphasize here that the Commission itself has on two recent occasions rejected this very argument. The first such occasion is the Final Policy Statement, which states a clear preference for "full decoupling" compared to "lost margin recovery mechanisms" (pp 28-29). Moreover, in contesting the lost fixed-cost recovery provision here, NRDC and other parties are giving the Commission the opportunity to make exactly the same choice that it faced in the recent Southwest Gas case, where a stipulation joined by both Staff and NRDC asked the Commission to select either a lost fixed-cost recovery mechanism (Alternative A, favored by Staff) or full revenue decoupling (Alternative B, favored by NRDC and SWEEP). The Commission chose Alternative B, reaffirming the preference stated in its Final Policy Statement;

> [A] partial decoupling mechanism such as is included in Alternative A could create conflicting incentives for the Company by, on the one hand, imposing significant energy efficiency goals that must be achieved while, on the other hand, leaving in place a structure that would concurrently provide an incentive for SWG to sell higher volumes of gas in order to improve its bottom line, thereby undermining the Policy Statement's goal of encouraging conservation. Another concern raised by Alternative A is the nature of the annual proceedings that would be required to

> review the performance of the LFCR mechanism, and the likelihood that those proceedings would be extremely adversarial as parties were forced to litigate on a yearly basis whether SWG had achieved the required energy efficiency goals. Further, as Mr. Cavanagh pointed out, adoption of Alternative A may cause SWG to pursue energy efficiency programs that look good on paper but deliver much less in actual savings.[3]

In its lost fixed-cost recovery provision, the Settlement Agreement is really just trying to resurrect Alternative A from the Southwest Gas case, in an attempt to displace another clearly preferable full decoupling mechanism.

Q. But doesn't the Settlement Agreement include an opt-out provision for its lost fixed cost recovery mechanism?

A. Yes, but the "opt-out" option requires customers to accept higher fixed charges and reductions in the rewards that they would otherwise receive in their APS bills for saving electricity. The Commission's Policy Statement considered this rate design option and noted that it would adversely affect low-income customers and discourage efficient energy use.[4] The Commission went on to reject a very similar proposal from RUCO in the recent Southwest Gas case, on the ground that it would not "be consistent with the stated goals of the Policy Statement."[5]

---

[3] Decision No. 72723, Docket No. G-01551A-10-0458 (January 6, 2012), pp. 39-40.
[4] Final Policy Statement, note 1 above, p. 28.
[5] Decision No. 72723, note 3 above, pp. 40-41.

Section 9.7 of the Proposed Settlement proposes the same kind of rate design change for large customers as a rationale for excusing them from contributing to the lost fixed-cost recovery mechanism. Again, in the Commission's own words, this move toward "fixed cost/variable pricing" and larger customer charges would mean "reduced variable charges, which discourages efficient energy use."[6]

Q. But, from a consumer perspective, wouldn't the one percent rate cap in the Settlement Agreement's LFCR mechanism be preferable to the three percent rate cap in the original APS decoupling proposal?

A. No, because the LFCR represents an automatic rate increase, whereas decoupling can either raise or reduce rates. Also, from a customer perspective, an even more invidious element of the Settlement Agreement is the ways in which it undercuts APS's incentive to achieve or exceed Arizona's energy efficiency targets and accompanying utility bill savings "on the order of $4.6 billion between 2011 and 2030."[7]

Q. Why would the Settlement Agreement impair those incentives?

---

[6] Final Policy Statement, note 1 above, p. 28.
[7] Id., p. 20 (comparing "high efficiency scenario" to "the business as usual case" for APS).

A. The Settlement Agreement does not make APS whole for lost fixed costs even from those sales that APS is judged to have lost as a result of its programs. The proposed LFCR affects only "a portion of distribution and transmission costs," and entirely omits fixed costs of generation.[8] This means that even for savings potentially eligible for fixed cost recovery under the Settlement Agreement, APS would be better off financially if it gave up the savings and received instead equivalent increases in retail sales. And of course, in the words of the Final Policy Statement, all other electricity savings would automatically "impact recovery of fixed costs and investment returns," even as "sales growth . . . offers the opportunity to recovery fixed costs and earn profit;" this is precisely the dilemma that the Commission aimed to eliminate in its Statement and its subsequent Southwest Gas decision.[9] The Proposed Settlement Agreement leaves the dilemma largely unaddressed.

**IV. RUCO'S TESTIMONY**

Q. How do you respond to RUCO's legal objections to revenue decoupling (Additional Direct Testimony of Frank W. Radigan, p. 14)?

---

[8] Proposed Settlement Agreement, p. 10, section 9.3.
[9] See Final Policy Statement, note 1 above, p. 2 and Decision No. 72723, note 3 above.

A. RUCO raised the same concerns in the recent Southwest Gas case, and a full rebuttal appears in the Commission's decision.[10]

Q. What is your response to RUCO's review of decoupling in other states?

A. It is an episodic and incomplete account (citing only nine states and the Southern Company, which has no experience whatever with decoupling), and it is no substitute for the comprehensive assessment of results from every adopted decoupling mechanism prepared by Pamela Lesh Morgan and published in the Electricity Journal, which is summarized in my direct testimony (see pp. 9-10). Moreover, as regards the only western state covered by the RUCO assessment (Washington), I note RUCO's wholly equivocal conclusion about the Commission's decision to terminate a complex rate adjustment mechanism that included a decoupling element among many other features:

> [T]he rate impacts of the resource-cost adjustment overwhelmed the rate impacts of the decoupling adjustment, making a fair comparison of decoupling with traditional ratemaking difficult.[11]

Finally, virtually everything in RUCO's skewed summary predates this Commission's Final Policy Statement and the

[10] Decision No. 72723, note 3 above, pp. 31-37.

[11] Additional Direct Testimony of Frank Radigan, p. 17: 3-5.

very complete record on which it relied; there is no new evidence here that might suggest a need to reopen the inquiry.

Q. How do you respond to RUCO's contention that Arizonans can't afford revenue decoupling at a time of severe economic distress?

A. Here, and in his characterization of decoupling as a "surcharge,"[12] RUCO's witness is acting under the apparent misapprehension that revenue decoupling somehow adds dollars to a utility's cost of service. Yet of course revenue decoupling adds no costs to customers' bills; it is a mechanism designed to ensure that utilities recover only the fixed costs of service that the Commission has reviewed and authorized in the previous rate case. That strikes me as sound policy in good and hard times alike, particularly since - as the Commission's Final Policy Statement attests - revenue decoupling is essential to achieving the multi-billion dollar economic benefits that cost-effective energy efficiency can bring to all Arizonans.

## V. AARP'S TESTIMONY

Q. How do you respond to AARP's negative response to

[12] Id., p. 10:8.

moves in the direction of straight fixed-variable rate design?[13]

A. I agree with her entirely, and note that her succinct assessment is starkly at odds with the lost fixed cost recovery provision of the proposed Settlement Agreement. Ms. Brockway is entirely right to say that reducing variable charges and raising fixed charges would mean that "the cost and effort of making usage more efficient would be rewarded with lower bill reductions."[14]

Q. What about AARP's critique of the company's decoupling proposal, including its treatment of weather?

A. Here the AARP testimony is wholly unpersuasive, in part because the author apparently is unaware of the Commission's Final Policy Statement (or at least she does not cite it). For example, her lengthy assessment of "weather risk" (pp. 26-28) is flatly inconsistent with the Statement's conclusion that "[w]eather normalization in the application of decoupling is discouraged because such normalization would reduce the size of decoupling surcredits to customers following an extreme weather event."[15] AARP's witness also invokes constitutional issues raised by ALJ Dwight Nodes during the review of

---

[13] Direct Testimony of Nancy Brockway, p. 23:1-13.
[14] Id., p. 23:11-12.
[15] Final Policy Statement, note 1 above, p. 31, no. 9.

Southwest Gas Corporation's revenue decoupling proposal,[16] but Judge Nodes ultimately concluded that the constitutional arguments against revenue decoupling were without merit, and the Commission decided as much in its final order.[17]

**VI. RECOMMENDATION**

Q. If the Commission agrees with your testimony, what action should it take on the Settlement Agreement?

A. I recommend that the Commission resolve the decoupling issue as it did in the Southwest Gas case, by approving the Settlement Agreement except for section IX, which describes the Lost Fixed Cost Recovery option. The Commission should substitute for that option the original APS decoupling proposal, as described and supported in my Direct Testimony.

Q. Does this conclude your testimony?

A. Yes.

[16] Direct Testimony of Nancy Brockway, p. 21: 14-22.
[17] Decision No. 72723, note 3 above, pp. 31-37.

EXHIBIT
RUCO
1

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 18, 2011

# TABLE OF CONTENTS

**INTRODUCTION**

**Q. MR. RADIGAN, WOULD YOU PLEASE STATE YOUR FULL 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 utility industries and specializing in the fields of rates, planning and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203. A summary of my education, my business experience and my qualification is attached as Exhibit-FWR-1.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO"). RUCO was established by the Arizona Legislature in 1983 to represent the interests of residential utility ratepayers in rate-related proceedings involving public service corporations before the Arizona Corporation Commission ("ACC" or "Commission").

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

A. I have been asked to review the reasonableness of the Arizona Public Service Company's ("APS" or the "Company") rate request filed on June 1, 2011 and present RUCO's recommended revenue requirement in this proceeding. Based on my adjustment together with the recommendations of RUCO witness William Rigsby RUCO proposes that no net change in rates be made at this time.[1]

**Q WHAT IS RUCO'S PHILOSOPHY GOING INTO THIS RATE CASE?**

A. RUCO was a signatory to the 2009 Settlement Agreement. At that time, RUCO's chief concern was to end the cycle of financial "emergencies" associated with the Company's corporate health. RUCO realized that it was not in the ratepayers' interest to have a utility continuously on the verge of falling below investment grade rating. The last few rate cases had provided just enough rate relief to keep its rating from falling to junk status, but never enough to achieve real financial health. RUCO believes the 2009 Settlement Agreement put APS on the path to financial health which resulted in ratepayer benefits such as the ability for the utility to acquire debt at lower rates.

The 2009 Settlement Agreement "jump started" APS's progress on this path to financial health. That said, one must also recognize that in these tough economic times one must also expect the Company to pare expenditures at every opportunity. It cannot be just a desire that utility companies tighten their belts at the same time that their customers are tightening, and sometimes retightening, theirs. As such, one needs to bring balance to the issue and that is what RUCO advocates.

[1] This is done through a combination an increase in bases rates with an equal offsets of credits available through Power Supply Adjustor.

RUCO's position in this rate case is to continue the momentum of the Settlement with a resolution of this rate case that culminates in continued strong financial metrics without unjustly enriching the utility at the expense of ratepayers. RUCO also supports the continued investment in renewable technologies and would allow for the inclusion of post-test year plant for this category. Our rate proposal is to increase base rates for infrastructure investment made up to the end of the test year and offset set the cost of supporting these investments with credits available through lower fuel costs available from the Power Supply Adjustor. This approach provides fairness and balance to stockholders and ratepayers. Stockholders receive the revenues necessary to pay for investments already made and ratepayers do not pay for investment made after the test year which gives the utility the incentive to invest wisely.

<u>**SUMMARY**</u>

**Q. COULD YOU PLEASE SUMMARIZE THE FINDINGS OF YOUR REVIEW?**

A. Yes. Company witness Jason LeBenz provided the standard filing requirement schedules and made a total of thirty-five adjustments to normalize the 2010 test year income statement. These adjustments included a series of normalization of 2010 revenues and expenses, adjustments to annualize latest knows costs to reflect such things as staffing levels and union contract rates and to make adjustments for out of period costs/revenue elements or other cost/revenues that are not expected to reoccur. A review of the presentation shows that the two most notable features of the rate request are a request for a return on equity of 11% and a request to be allowed to charge for 18 months of post-test year plant additions in amount of approximately $690 million. These two items account for approximately $150 million of the $194 million non-fuel base rate increase. In short they drive the whole case.

The focus of allocating risk between company and ratepayers plays on several proposals made by the Company in this case. The Company has much ability to control costs as compared to ratepayers and should bear the risk of minimizing them. With this in mind, my recommendations are reflected in RUCO's cost of service exhibits which are appended as Exhibit--FWR-2 and reflect the following recommendations:

1. A net rate decrease of $0 million.
2. No post-year year plant additions for fossil, nuclear or distribution plant.
3. Allow recovery of test year AZ Sun costs and 18 months of post test year AZ Sun costs.
4. Continuation of the Power Supply adjustment ("PSA") with 90/10 sharing.
5. Reject the proposal to include chemical costs in the PSA.
6. Reject the proposal to establish an Environmental and Reliability Account.
7. Rejection of coal mine reclamation cost adjustment which would allow a four year recovery of costs.
8. Rejection at this time of Company's low income adjustment.

9. The Company's Decoupling Mechanism (the Energy and Infrastructure Account) is a rate design issue and will be addressed in the RUCO testimony to be filed on December 2, 2011.

The implementation of these recommendations result in a base rate increase of $140 million (a $98 million increase in base rate to covers costs and a $42 million from the transfer of the Az Sun program funding from the RES to base rates) offset by a credit of $140 million from the PSA. I would note that the PSA does have a credit of $153 million so the $140 million transfer still leaves another $13 million credit in the PSA which can be used to offset future rate increases. A summary of the details of the rate change of the Company and RUCO is presented in the table below.

| Rate Element | APS Position - 10/27 ($Millions) | RUCO Position ($Millions) |
|---|---|---|
| Base Rates | $196 | $98 |
| Az Sun transfer to base rates | $42 | $42 |
| Base Fuel Change | ($153) | ($140) |
| Net Rate Change | $85 | $0 |

**Q. PLEASE CONTINUE**

A. The Company's presentation in this case is essentially a continuation of the Settlement in the last Arizona Public Service ("APS") rate case, Docket No. E-

01345A-08-0172, which was approved by the Commission in Decision No 71448 (the "Settlement"). As testified to by Company Witness Guldner the Company views this proceeding as critical in maintaining the financial and regulatory momentum established in the Settlement (Guldner direct at page 1, lines 22-25). As described by Mr. Guldner the Settlement marked a turning point in providing for the electric infrastructure needed for Arizona's future while allowing APS the financial strength and stability to attract capital (Id at page 2). This was done by providing significant cash relief and other mechanisms (Id). The Company's presentation seeks to reset base rates at a level which is described as a moderate increase and reset many of the cost recovery mechanisms currently in place and establish a series of other automatic adjustment clauses which it describes as improving its financial health while also meeting regulatory objectives (e.g. rate decoupling so that energy conservation programs can succeed). In fact, the Company's whole case is based on non-traditional ratemaking proposals – post-test year plant recovery, automatic adjustors and decoupling.

The Settlement was a comprehensive resolution of numerous and divergent issues in 2009 that set the stage for long term financial health of the Company while at the same time achieving some energy efficiency goals and commitments to renewable energy goals. One provision that does carry forward is the commitment to process rate cases within 12 months. This is a provision that will benefit the Company for the long term and the value of this one provision is evidenced by the Company's own presentation.

> "APS's financial pressure is not caused by too much debt, operational inefficiency, or poor cost management. Rather, the primary cause of APS's substandard financial performance is the rate making process in Arizona has been lengthy (often taking, for APS as much as 18-24 months to resolve) and is based on a historical test year – conditions resulting in persistent regulatory lag. Under such a regulatory model, the rates set in APS rate cases have historically been based on costs as much as three to five years old." (Hatfield direct at page 4)

With the commitment by the Commission to streamline the rate review process the primary cause of the Company's past substandard financial performance is now history. With that gone one does not need to adopt the non-traditional ratemaking techniques used in the Settlement. One of those non-traditional provisions of the Settlement is the one for providing for a return on post-tear year plant additions. This provision was unique to that case as it addressed the Company's financial health and the fact that it took almost two years to adjudicate the case. The normal regulatory framework in Arizona is to set rates on a historical test year basis and provide for a return on equity higher than that usually set for utilities that use a pro-forma test year. While this regulatory framework may result in regulatory lag on the recovery of return on investment it also provides the Company an incentive to be frugal in investment decisions and adequately rewards stockholders for the added risk. Central to the RUCO presentation therefore is strict adoption of no pro-forma adjustments and providing for a higher return on equity. This focus will continue to provide the Company the ability to strengthen its financial metrics while at the same time keeping rates at reasonable levels.

## REVIEW OF RATE REQUEST

**Q. PLEASE DISCUSS THE COMPANY'S FILING**

A. On June 1, 2011, APS filed a rate case using adjusted Test Year sales and expenses for the Company's jurisdictional electric operations for the twelve months ended December 31, 2010 ("Test Year"). The rate request was to increase base rates by a net $95 million. The net $95 million was comprised of three parts a need for a non-fuel increase in base rates of $194 million, a transfer of $45 million of revenues to support the Az Sun Program from the Renewable Energy Surcharge ("ERS") to base rates and a decrease in base fuel expense of $144 million[2].

In addition to the base rate change in its presentation the Company also made a series of proposals for new riders, adjustment mechanisms, modifications to existing mechanisms including a decoupling mechanism, an adjustment to reflect increase in generation plant balances, removal of cost sharing on the power supply adjustor, and a mechanism to recover costs for efficiency programs. Through a variety of witnesses the case has been largely summarized by the Company as a continuation of the Company's last rate case which was widely viewed as a milestone that set the stage for positive developments in Arizona energy policy (Robinson direct at page 4). According to the Company the rate

[2] On October 27, 2011 the Company updated its filing and reduced its rate request to $85 million with the non-fuel base rate increase being revised to $196 million, the Az Sun Program revised to $42 million and the base fuel expense being reduced by $153 million.

request seeks to continue the momentum set in the last rate case and take further steps to make Arizona's energy landscape sustainable for the long term (Id).

**Q. PLEASE DISCUSS RUCO'S REVIEW OF THE COST OF CAPITAL.**

A. Mr. William Rigsby presents the RUCO recommendations on the weighted average cost of capital, the return on equity and the recommended rate treatment to reflect fair value rate of return. Mr. Rigsby recommends a slightly lower cost of long term debt and a return on equity of 10% for plant at original cost and a Fair Value Rate of Return of 6.1%. This compares to the company's request of a 11% return on equity and a Fair Value Rate of Return of 6.47%. These recommendations lower the overall average rate of return from the Company's proposed 8.87% to 8.27%. If no other change were made this recommendation would decrease the updated rate request from $85 million to a rate increase of $40 million or $45 million.

**Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED POST TEST YEAR ADJUSTMENTS?**

A. As noted above the company proposes to adjust for 18 months of post test year operation and maintenance expenses as well as post test year plant additions for nuclear power, fossil generation, distribution and general plant additions[3]. The operating expenses related to this proposal decrease net income by approximately

[3] The Company also proposes to transfer expenditures related to the Az Solar Program from the RES to base rates. RUCO agrees with this proposal as it merely transfers the revenue collection mechanism from the RES to base rates.

$15.3 million and increase rate base by $141 million. Together they increase the revenue requirement in this case by approximately $35 million.

The Commission has consistently ruled that post test year plant additions are generally not allowed unless extraordinary circumstances are shown to exist.[4] Every piece of evidence in this case has shown that the Company's financial health has improved. For example S&P upgraded the Company's credit rating in 2010 after the last rate case. As to necessary capital improvements I make the distinction between those necessary to serve new customers and forecast capital programs. In this case the Company has only identified $140 million of the $690 million as projects related to new customers coming on the system. The rest are upgrades to the existing equipment and can for the most part considered discretionary.

The 2009 Settlement Agreement included 18 months of post test year plant. However, that was a negotiated concession as a result of much give and take. Here, the Company requests the same amount of post test year plant without any acquiescence in other areas.

[4] See Decisions 7001 and 7360.

**Q. DOES RUCO SUPPORT INCLUSION OF ANY POST TEST YEAR PLANT?**

A. Yes. RUCO supports inclusion of 18 months of post test year plant for the Company's AZ Sun program. While acceptance of such plant outside of a test year is unprecedented for RUCO, RUCO does so because it recognizes the commitment the Arizona Corporation Commission and other branches of Arizona state government have made to encourage the expansion of solar and other renewable energy generation.

<u>FOUR CORNERS COAL RECLAMATION COSTS</u>

**Q. COULD YOU PLEASE DISCUSS THE APS PRO-FORMA ADJUSTMENT FOR THE COAL RECLAMATION COSTS AT THE FOUR CORNERS POWER PLANT?**

A. Yes, per the contract with its coal supplier the Company must pay for the reclamation of the coal mine and environs at the time that the mine for this mine mouth power plant is retired (See response to 25.15 attached as Exhibit FWR-3). Reclamation is necessary as mining disturbs land and leaves waste material. Modern mines reclaim the surface after mining is completed and return the land to useful purposes. Currently the date for the closure of Units 1-3 at Four Corners is estimated to be July 6, 2016 when the current coal contract expires (Id). In order to recover the portion of the latest coal reclamation cost estimate by the time the units retire related to Units 1-3, the Company has amortized the cost over four years (Id). The Company's use of the latest coal reclamation cost estimate and the short life for Units 1-4 cause an increase in costs from the test year amount of \$1.3 million to \$7.5 million for a decrease in pro-forma operating income of \$6.2 million (See APS JCL-WP32 IS Pro forma Annualize Four Corners Coal Reclamation Costs attached as Exhibit FWR-4).

**Q. DO YOU AGREE WITH THIS ADJUSTMENT?**

A. No. First, it is not certain that Units 1-3 will be shut down at this time. In October 2010 the EPA wanted to have the Company install selective catalytic reduction equipment on all five units at Four Corners and in February 2011 EPA changed its mind and wanted to close Units 1-3 and install Best Available Control Technology on Units 4-5 (see EPA Proposed Actions attached as Exhibit FWR-4). Obviously the EPA does not have a final plan as of yet. The Company is equally two faced. For depreciation and coal reclamation purposes the Company is planning a retirement data of 2016. Yet, the capital planning the Company is proposes to add \$13.1 million of capital projects at Units 1-3 in its Post-Test Year Plant Addition adjustment presented by Company Witness Schiavoni. These projects include over \$2 million in reliability upgrades to maintain the units for the long term (See Exhibit MAS-1). In addition in his testimony Mr. Schiavoni also has a picture of the new economizer being installed at Four Corners Unit 1 (See Schiavoni direct at page 9). An economizer which is a central part of a generating plant would not be knowingly upgraded on a Unit that is only going to provide only four more years of service. With all of these facts it is not a certainty that Units 1-3 will be retired in 2016. As such, at least for coal reclamation purposes the pro-forma adjustment should be rejected and replaced with one that reflects just the updated cost reclamation estimate. This results in a recovery of the reclamation costs over a longer period, 26 years, which is the projected service life of Four Corners Units 4 and 5 and is exactly the methodology that the Company depreciation expert proposed for recovery the unrecovered book reserve for Units 1-3 (See White direct at page 10). This proposal increases pro-forma net income by $1.6 million.

**<u>LOW INCOME CUSTOMER DISCOUNT</u>**

**Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED PRO-FORMA ADJUSTMENT FOR THE LOW INCOME CUSTOMER DISCOUNT?**

A. APS is proposing to adjust test year revenues to reflect the growth in low income programs from the end of the test year to mid-year 2012, when new rates are projected to be implemented (See Meissner direct at page 37). Low Income programs offer a lower base rate and a bill discount program. The Company reports that the programs resulted in test year base revenues being lower by approximately $20 million dollars (Id). For the rate case the Company proposes that it be allowed to reflect a growth in losses resulting from the low income program (Id). The Company notes that between January 2010 and December 2010 the number of customers participating in low income programs grew from 58,885 to 66,738 for an annual growth rate of 13.3% (Id). The Company projects this growth to continue at this annual growth rates and proposes an adjustment to test year revenues for low income programs is a reduction of $4.2 million (Id). APS believes that this adjustment to test year revenues is reasonable and appropriate since the amounts are known and measureable and occur in direct proximity to the test year (Meissner direct at page 38).

**Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?**

A. No. The Company's justification for this adjustment is one data point the growth between January 2010 and January 2011. This is not indicative of any trend let alone good justification of a pro-forma adjustment to rates. Besides the fact economic conditions in Arizona are improving. According to the Bureau of Labor Statistics the unemployment rate in Arizona has decreased from 9.6% in December 2010 to 9.1% in September 2011[5]. If economic conditions continue to improve there is a possibility that the number of low income customers could actually decrease. Based on the one data point presented by the Company I believe that the Company has not met its burden of proof that its proposed adjustment is actually known and actually measurable. Rejection of this proposal increase pro-forma net income by $2.6 million ($4.2 million of revenues less income taxes).

---

[5] http://data.bls.gov/timeseries/LASST04000003

## <u>ADJUSTOR MECHANISMS</u>

**Q. PLEASE DISCUSS THE COMPANY'S PROPOSED ADJUSTOR MECHANISMS**

A. As noted above the Company has proposed a series of adjustor mechanisms in this proceeding. Some such as the ERA are completely new and others such as proposed changes to the PSA are a modification to existing mechanisms already in place. Overall, the proposed mechanisms seek to give the Company greater protection of its bottom line, i.e. net income. For example, modifications to the PSA are designed to protect the Company from increases in the cost of chemicals and relieve the Company from sharing in fuel cost variations. Another example is the proposed ERA where the Company would be allowed to recover any investment in its generating plant.

The Arizona Court of Appeals discusses adjustment mechanisms in <u>Scates v. Arizona Corporation Commission</u>. The court indicated that such mechanisms are restricted to certain narrowly defined operating expenses that are characterized by fluctuations. The Commission has also defined adjustment mechanisms as applying to expenses that routinely widely fluctuate. The Commission stated the following regarding adjustor mechanisms:

> The principle justification for a fuel adjustor is volatility in fuel prices. A fuel adjustor allows the Commission to approve changes in rates for a utility in response to volatile changes in fuel or purchased power prices without having to conduct a rate case. (Arizona Public Service Company, Decision No. 56450, Page 6, dated April 13, 1989)

With the possible exception of the Company's proposed fuel and purchased power adjustor, none of the proposed mechanisms fit the criteria of a widely fluctuating volatile expense. In fact the returning customer, transition cost, and systems benefit proposed adjustors merely provide for the recovery of discrete and finite sets of expenses that can be quantified with certainty and will not be subject to cost volatility. These proposed mechanisms would more aptly be described as surcharges rather than adjustors.

The Company has repeatedly stated that its proposed adjustor mechanisms comport with and continue the spirit of the 2009 Settlement Agreement. However, RUCO points out that the Settlement was a well-debated negotiated settlement that was fair to both the utility and the ratepayers. While the Settlement did provide several benefits to the utility, it also included numerous ratepayer benefits including requiring the utility to contain its expenses. In its Application, the Company ***adds*** to the benefits it received in the Settlement such as the ERA, including chemicals in the PSA, eliminating the 90/10 sharing provision, a decoupling mechanism, but makes not additional commitments that inure to the benefit of the ratepayer.

**<u>PROPOSED MODIFICATION TO PSA</u>**

**Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL FOR MODIFICATION TO THE PSA.**

A. Company witness Peter Ewen proposes two modifications to the PSA. The first is to remove the 90/10 sharing provision which was approved by the Commission in Decision No. 69663 (June 28, 2007) and the second is to include the cost associated with environmental chemical costs, primarily lime, in the PSA (Ewen Direct at page 13).

As to the 90/10 Sharing provision the Company proposes that the PSA be modified to allow full pass-through of all fuel and purchased power costs, instead of the current sharing provision whereby the Company is only allowed to recover can only recover from customers 90% of most fuel expenses above the amounts recovered through the Base Fuel Rate (Ewen at page 15). To support its position to change the PSA the Company has four main arguments. First, it states that it is the only Company to have a 90/10 sharing provision in Arizona (Ewen direct at page 14). Since the implementation of the sharing provision there have been audits of the Company's fuel procurement practices which showed that APS's hedging and procurement practices and deemed them to be sound (Id). In addition, the soundness of its fuel purchasing strategy was recently confirmed in a benchmarking study (Id). Third, the Company notes that through the recent adoption of the new Integrated Resource Planning Rules ("IRP"), the Commission will effectively approve the Company's proposed resource mix so presumably the

Company is acting prudently in that area (Id). Fourth, the Company argues that the only other variables that exist are fuel costs (the cost of fuel and purchased power market prices) which is something entirely outside of APS's control and power plant operations (Id). On power plant operations the Company argues these have been effectively reviewed in prudence determinations (Id).

**Q. DO YOU AGREE WITH THE COMPANY'S REASONING?**

A. No. Sharing provisions are established so that the utility has a financial incentive to control the cost which comprises approximately one third of the customers' bill. While the Company argues that it has no control over market prices for fuel and purchased power, customers have even less. Customers must rely on the utility to use its best efforts to keep costs at a minimum and a sharing mechanism is the best way to do that. The Company's own arguments belie its efforts in this area. The Company hedges fuel costs because they are at risk for market price increase. In the IRP process the Commission does not assume responsibility of the resource mix but is there to make sure the Company is doing lest cost planning. As to power plant operations the Company's coal and nuclear power plant run at very high availability and capacity factors. This is not done by chance but rather by the Company's efforts to keep them up and running. And this is exactly the outcome one wants as high availability of these low cost resources keeps fuel costs down. The PSA is a much better control for this type of efforts on the Company's part on a day to day basis rather than some after the fact prudence case.

**Q. PLEASE DISCUSS THE INCLUSION OF ENVIRONMENTAL CHEMICAL COSTS IN THE PSA.**

A. The Company is proposing to include in the PSA environmental chemical costs that directly correlate to the use of fuel. Chemicals, such as lime, ammonia, and sulfur are used to scrub the emissions from a coal plant and are dependent upon the amount of fuel burned (Ewan direct at page 15). The Company argues that as production from the power plants varies, so too does the amount of chemicals used and therefore its costs (Id). Moreover, the Company also notes that chemical costs will increase over time (Ewan direct at page 16).

While I understand the Company's viewpoint of where it would like to be relieved from worrying about cost increases for chemicals there is nothing special about these costs nor is there a showing that they are highly volatile or material to the Company's operation. The test year cost of chemicals is built into base rates and between rate cases it is a cost of doing business just like thousands of other expense items that the Company has. The Company has shown no compelling reason to include this cost in the PSA and the proposal should be rejected.

**PROPOSED ERA**

**Q. COULD YOU PLEASE DISCUSS THE COMPANY'S PROPSOAL FOR THE ENVIRONMENTAL AND RELIABILITY ACCOUNT?**

A. Yes. As presented by Company Witness Leland Snook the Company proposes to establish an Environmental and Reliability Account ("ERA") mechanism that will allow it to recover the carrying costs of environmental improvement and generation plant capacity acquisition or additions (Snook direct at page 23). The ERA would include environmental improvement projects which are designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws or regulations (Snook at page 25). Generation plant capacity acquisitions, projects to improve efficiency or the construction of new generating plant would also be included (Id). For example, APS's pending acquisition of Southern California Edison's share of Four Corners Units 4 and 5 would be Qualified Investments for inclusion in the ERA in the year following the close of the transaction (Id). Under the Company's proposal it will calculate the ERA adjustment based on the investments that were actually placed in-service during the preceding calendar year and adjust rates on an annual basis (Snook direst at page 24). The Company believes this feature of the ERA complements its proposed post-Test Year plant adjustment proposed by APS witnesses Schiavoni, Edington and Froetscher (Snook direct at page 25).

**Q. ARE THERE ANY OTHER CONSIDERATIONS THAT SHOULD BE TAKEN INTO ACOCUNT WITH RESPECT TO THIS AUTOMATIC ADJUSTOR?**

A. Yes, the most practical one and that is need. One needs to remember that the utility business is one of very long term capital intensive assets. These are not costs that are highly volatile or made at a moment's notice. This is especially true for capital investments for environmental reasons or additions for capacity and/or reliability. Investments for power plant reliability or environmental compliance are easily contrasted to the utility's real short term capital needs of hooking up a new customers or replacing a street or traffic light that was demolished by a car in a rainstorm. These are low cost items easily available in inventory with construction time in hours.

Contrast the Street Light with the Economizer Replacement at the Cholla 3 Unit. This project is as $4.5 million project which is necessary to improve unit reliability due to tube failures (See Exhibit MAS 1, page 1 of 24). The economizer is a central component of any steam boiler whose purpose is to reheat condensed steam coming out of the steam turbine up to but not at the boiling pint of water. As the name implies it uses the waste heat of the steam to reheat water thereby providing improved economy to the Rankine cycle. In order to perform this project one first needs to experience the tube failures. This takes time. One then needs to analyze cause of the failures and possible solutions to the problem. This takes times. One then need to perform the economic cost of letting the problem continue versus the cost of fixing the problem. If the benefit of fixing the problem exceeds the cost, then a proposal is made to Company management to fix the problem. This takes time.

At a total cost of $4.5 million the project needs to be engineered and specifications sent out to bid. Bids must be then received and analyzed and then the most important part of all, the project must be scheduled. Project scheduling not only involves for arranging for labor and materials but also outage time of the unit itself. As I mentioned before the economizer is a central part of the steam boiler as a whole. To replace it therefore means that the unit must be shut down. Shutting down and restarting a steam boiler means shutting it down, letting it cool, draining the water out of all piping, erecting scaffolding to perform the work, performing the work, testing for leaks, demolishing scaffolding, filling the unit with water, testing again, and then finally restarting the unit. This process usually takes on the order of 5-12 weeks. One must also remember that the work must be done when the plant is down for maintenance which usually occurs doing the non-peak (i.e. not summer) period. For beginning to end this reliability project at Cholla Unit 3 could take a matter of years.

Just as with the Cholla economizer environmental projects are usually years in the making with the regulation being drafted, send out for comment, revised, compliance plans prepared and filed and then project planning can commence. In sum, I reject the notion that these types of projects are highly volatile in nature and cannot be planned with a reasonable degree of accuracy.

**Q. WHAT DO YOU RECOMMEND?**

A. The ERA should be rejected. According to the proposed plan of administration all any project needs to qualify is that the plant in generation, it has a work order, and it costs will exceed $500,000 (Attachment LRS-3). With this definition and the low dollar threshold I believe that almost <u>any</u> project at a generation plant would qualify for recovery. Similar to the post-test plant adjustment the

Company is seeking the Commission to approve a mechanism that will act as a formula rate whereby rates are continually adjusted upward to fund the Company's growth strategy.

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

A. Yes, it does.

Exhibit__(FWR-1)

# QUALIFICATIONS OF FRANK W. RADIGAN

**Q. MR. RADIGAN, WOULD YOU PLEASE STATE YOUR FULL 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 utility industries and specializing in the fields of rates, planning and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203

**Q. WOULD YOU PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?**

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the Department of Public Service, the staff arm of the New York State Public Service Commission. I served in the Rates and System Planning sections of the Power Division and in the Rates Section of the Energy and Water Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State and encompassed rate design and performing embedded and marginal cost of service studies, as well as depreciation studies.

Before leaving the Commission, I was responsible for directing all engineering staff during major proceedings, including those relating to rates, integrated resource planning and environmental impact studies. In February 1997, I left the Commission and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own company.

In my 30 years of experience, I have testified as an expert witness in utility rate proceedings on more than 100 occasions before various utility regulatory bodies, including the Arizona Corporation Commission, the Connecticut Department of Utility Control, the Delaware Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board and the Federal Energy Regulatory Commission.

I currently advise a variety of regulatory commissions, consumer advocates, municipal utilities and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my qualifications and experience is attached.

# FRANK W. RADIGAN

## EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

## SUMMARY OF PROFESSIONAL EXPERIENCE

*1998-Present* **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

*1997-1998* **Manager Energy Planning, Louis Berger & Associates, Albany, NY** - Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

*1981-1997* **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** - Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

## FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

## PROJECT HIGHLIGHTS

*Wholesale Commodity Markets*

**Transmission Expansion Planning** - Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool - the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

**Locational Based Pricing** - Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

**Merchant Plant Analysis** – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

**Market Price Forecasting** - El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

**Market Price Analysis** – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

**Gas Aggregation** – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

**Gas Procurement** – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

**HQ Prudence Review** - Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

**Wholesale Power Supply** – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

**Analysis of Load Pockets and Market Power** - Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

**Study of IPP Contracts and Impacts in New York** Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

**Power Purchase Contract Policies and Procedures** - Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

**Integrated Resource Planning** - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

**Intrastate Wheeling Commission Transmission Analysis and Assessment** – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

### *Rate Setting*

**Jurisdictional Cost of Service** – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

**Rate Case Cost of Service Study** – Heritage Hills Water Works- For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

**Rate Case Cost of Service Study** - Stowe Electric Department, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

**Rate Study** - Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation.

**Rate Case Cost of Service Study** - Village of Greene, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

**Rate Case Cost of Service Study** - Village of Bath, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

**Rate Case Cost of Service Study** - Village of Richmondville, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

**Economic Development Rate** - Massena Electric Department - For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

**Rate Case Cost of Service Study** - Village of Hamilton, NY - For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

**Rate Study** - Pascoag Utility District - Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

**Rate Study** - Kennebunk Power and Light Department - Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

**Rate Case Cost of Service Study** - Village of Arcade, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

**Rate Case Cost of Service Study** - Village of Philadelphia, NY - For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

**Rate Case Cost of Service Study** - Village of Hamilton, NY - For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

**Rate Case Cost of Service Study** - Fillmore Gas Company - For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

**Rate Case Cost of Service Study** - Rowlands Hollow Water Works- For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

**Standby Rates**- Independent Power Producers of New York - Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

**Economic Development Rates**- Pascoag Utility District - Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

**Municipalization Study** – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

**Water Rate Study** – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

**Pole Attachment Rates** – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

**ISO Service Tariff** -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

**Pole Attachment Rates** – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

**OATT Rates** – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

**Consolidated Edison Restructuring** - Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

**Cost-of-service Review and Rate Unbundling** – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

**Vintage Year Salvage and Study** - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

*Environmental Issues*

Energy Conservation Study – **Pascoag Utility District - Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002**

**Clean Air Act Lawsuit** - New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

**Environmental Impact Study and Simulation Modeling Analysis** – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

**Renewable Resources** - Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

**Environmental and Economic Impacts Study** - Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

**Clean Air Impact Study** – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

**Environmental Externalities and Socioeconomic Impacts Study** - Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

## EXPERT WITNESS TESTIMONY

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel fo the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in deprecation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design and its for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

## PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

## MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

Exhibit__(FWR-2)

Exhibit Schedule List

RUCO Schedule A-1

RUCO Schedule B-1

RUCO Schedule B-2

RUCO Schedule B-3

RUCO Schedule C-1

RUCO Schedule C-2

RUCO Fair Value Increment

RUCO Working Capital Adjustment

RUCO Pro-Forma Income Tax Calculation and Interest Expense Synchronization

# RUCO Schedule A-1

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | Electric Original Cost | Electric RCND | Electric Fair Value | Line No. |
|---|---|---|---|---|---|
| 1. | Adjusted Rate Base | $ 5,544,426 (a) | $ 10,555,837 (a) | $ 8,050,131 | 1. |
| 2. | Adjusted Operating Income | 491,057 (b) | 491,057 (b) | 491,057 (b) | 2. |
| 3. | Current Rate of Return | 8.86% | 4.65% | 6.10% | 3. |
| 4. | Required Operating Income | 458,524 | 458,524 | 458,524 | 4. |
| 5. | Required Rate of Return | 8.27% * | 4.34% * | 5.70% * | 5. |
| 6. | Adjusted Operating Income Deficiency | (32,533) | (32,533) | (32,533) | 6. |
| 7. | Gross Revenue Conversion Factor | 1.6532 (c) | 1.6532 (c) | 1.6532 (c) | 7. |
| 8. | Requested Increase in Base Revenue Requirements | $ (53,784) ** | $ (53,784) ** | $ (53,784) ** | 8. |
| 9. | Fair Value Increment | | | 53,784 (d) | 9. |
| 10. | Requested Increase in Base Revenue Requirements | | | $ 0 | 10. |
| 11. | Required Rate of Return with Fair Value Increment | | | 6.10% (d) | 11. |

Notes:
* The Required Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.

** *Does not include the fair value increment reflected on Line 9.*

Supporting Schedules:
(a) RUCO B-1
(b) RUCO C-1, page 2 of 2
(c) RUCO C-3
(d) RUCO Fair Value Increment

Recap Schedules:
N/A

# RUCO Schedule B-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| | | Original Cost | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Total Company | | | ACC | | | |
| Line No. | Description | Unadjusted Test Year (a) (A) | Pro Forma (a) (B) | Adjusted Test Year (a) (C) | Unadjusted Test Year (a) (D) | Pro Forma (a) (E) | Adjusted Test Year (a) (F) | Line No. |
| 1. | Gross utility plant in service | $ 13,656,105 | $ 246,932 | $ 13,903,037 | $ 11,522,113 | $ 238,536 | $ 11,760,649 | 1. |
| 2. | Less: Accumulated depreciation & amortization | 5,219,000 | 1,958 | 5,220,958 | 4,528,867 | 1,892 | 4,530,759 | 2. |
| 3. | Net utility plant in service | 8,437,105 | 244,974 | 8,682,079 | 6,993,246 | 236,644 | 7,229,890 | 3. |
| | Deductions: | | | | | | | |
| 4. | Deferred income taxes | 1,931,063 | 1,862 | 1,932,925 | 1,567,902 | 1,799 | 1,569,701 | 4. |
| 5. | Investment tax credits | 907 | - | 907 | 876 | - | 876 | 5. |
| 6. | Customer advances for construction (c) | 121,645 | - | 121,645 | 121,645 | - | 121,645 | 6. |
| 7. | Customer deposits | 68,084 | - | 68,084 | 68,084 | - | 68,084 | 7. |
| 8. | Pension and other postretirement liabilities | 711,164 | - | 711,164 | 661,518 | - | 661,518 | 8. |
| 9. | Liability for asset retirements (c) | 328,571 | - | 328,571 | 320,592 | - | 320,592 | 9. |
| 10. | Other deferred credits | 66,842 | - | 66,842 | 64,107 | - | 64,107 | 10. |
| 11. | Coal mine reclamation (c) | 117,243 | - | 117,243 | 114,396 | - | 114,396 | 11. |
| 12. | Unrecognized tax benefits (c) | 65,363 | - | 65,363 | 53,961 | - | 53,961 | 12. |
| 13. | Regulatory liabilities | 260,687 | - | 260,687 | 253,750 | - | 253,750 | 13. |
| 14. | Total deductions | 3,671,569 | 1,862 | 3,673,431 | 3,226,831 | 1,799 | 3,228,630 | 14. |
| | Additions: | | | | | | | |
| 15. | Regulatory assets | 822,177 | - | 822,177 | 746,508 | - | 746,508 | 15. |
| 16. | Deferred debit income tax receivable (c) | 65,498 | - | 65,498 | 63,271 | - | 63,271 | 16. |
| 17. | Other deferred debits | 77,674 | - | 77,674 | 72,203 | - | 72,203 | 17. |
| 18. | Decommissioning trust accounts (c) | 469,886 | - | 469,886 | 458,476 | - | 458,476 | 18. |
| 19. | Allowance for working capital (d) | 233,778 | (8,935) | 224,843 | 212,065 | (9,357) | 202,708 | 19. |
| 20. | Total additions | 1,669,013 | (8,935) | 1,660,078 | 1,552,523 | (9,357) | 1,543,166 | 20. |
| 21. | Total rate base | $ 6,434,549 | $ 234,177 | $ 6,668,726 | $ 5,318,938 | $ 225,488 | $ 5,544,426 (e) | 21. |

Supporting Schedules:
(a) RUCO B-2
(b) RUCO B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) RUCO A-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| | | RCND | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Total Company | | | ACC | | | |
| Line No. | Description | Unadjusted Test Year (b) (A) | Pro Forma (b) (B) | Adjusted Test Year (b) (C) | Unadjusted Test Year (b) (D) | Pro Forma (b) (E) | Adjusted Test Year (b) (F) | Line No. |
| 1. | Gross utility plant in service | $ 26,378,778 | $ 246,932 | $ 26,625,710 | $ 22,255,775 | $ 238,536 | $ 22,494,311 | 1. |
| 2. | Less: Accumulated depreciation & amortization | 9,826,977 | 1,958 | 9,828,935 | 8,527,851 | 1,892 | 8,529,743 | 2. |
| 3. | Net utility plant in service | 16,551,801 | 244,974 | 16,796,775 | 13,727,924 | 236,644 | 13,964,568 | 3. |
| | Deductions: | | | | | | | |
| 4. | Deferred income taxes | 4,057,550 | 1,862 | 4,059,412 | 3,294,325 | 1,799 | 3,296,124 | 4. |
| 5. | Investment tax credits | 907 | - | 907 | 876 | - | 876 | 5. |
| 6. | Customer advances for construction (c) | 121,645 | - | 121,645 | 121,645 | - | 121,645 | 6. |
| 7. | Customer deposits | 68,084 | - | 68,084 | 68,084 | - | 68,084 | 7. |
| 8. | Pension and other postretirement liabilities | 711,164 | - | 711,164 | 661,518 | - | 661,518 | 8. |
| 9. | Liability for asset retirements (c) | 328,571 | - | 328,571 | 320,592 | - | 320,592 | 9. |
| 10. | Other deferred credits | 66,842 | - | 66,842 | 64,107 | - | 64,107 | 10. |
| 11. | Coal mine reclamation (c) | 117,243 | - | 117,243 | 114,396 | - | 114,396 | 11. |
| 12. | Unrecognized tax benefits (c) | 65,363 | - | 65,363 | 53,961 | - | 53,961 | 12. |
| 13. | Regulatory liabilities | 260,687 | - | 260,687 | 253,750 | - | 253,750 | 13. |
| 14. | Total deductions | 5,798,056 | 1,862 | 5,799,918 | 4,953,254 | 1,799 | 4,955,053 | 14. |
| | Additions: | | | | | | | |
| 15. | Regulatory assets | 822,177 | - | 822,177 | 746,508 | - | 746,508 | 15. |
| 16. | Deferred debit income tax receivable (c) | 65,498 | - | 65,498 | 63,271 | - | 63,271 | 16. |
| 17. | Other deferred debits | 77,674 | - | 77,674 | 72,203 | - | 72,203 | 17. |
| 18. | Decommissioning trust accounts (c) | 469,886 | - | 469,886 | 458,476 | - | 458,476 | 18. |
| 19. | Allowance for working capital (d) | 233,778 | (8,935) | 224,843 | 212,065 | (6,201) | 205,864 | 19. |
| 20. | Total additions | 1,669,013 | (8,935) | 1,660,078 | 1,552,523 | (6,201) | 1,546,322 | 20. |
| 21. | Total rate base | $ 12,422,758 | $ 234,177 | $ 12,656,934 | $ 10,327,193 | $ 228,644 | $ 10,555,837 (e) | 21. |

Supporting Schedules:
(a) RUCO B-2
(b) RUCO B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) RUCO A-1

# RUCO Schedule B-2

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (1) Actual at End of Test Year 12/31/2010 (a) Total Co. (A) | ACC (B) | (2) West Phoenix Unit 4 Regulatory Disallowance Total Co. (C) | ACC (D) | (3) Updated in Staff 6.55 (Supplemental) Solar Generation Post-Test Year Plant Additions Total Co. (E) | ACC (F) |
|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ 13,656,105 | $ 11,522,113 | $ (13,833) | $ (13,363) | $ 260,765 | $ 251,899 |
| 2. | Less: Accumulated Depreciation & Amort. | 5,219,000 | 4,528,867 | (3,635) | (3,511) | 5,593 | 5,403 |
| 3 | Net Utility Plant in Service | 8,437,105 | 6,993,246 | (10,198) | (9,852) | 255,172 | 246,496 |
| 4. | Less: Total Deductions | 3,671,569 | 3,226,831 | (1,469) | (1,419) | 3,331 | 3,218 |
| 5. | Total Additions | 1,669,013 | 1,552,523 | - | - | - | - |
| 6. | Total Rate Base | $ 6,434,549 | $ 5,318,938 | $ (8,729) | $ (8,433) | $ 251,841 | $ 243,278 |
| | **WITNESS:** | | | LA BENZ | | GULDNER / LA BENZ | |

(1) Test Year Total Deductions and Total Additions are shown on Schedule RUCO B-1.

(2) Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decisions Nos. 67744 and 69663.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) E-1

APS Update
RUCO Adjustment

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (4) Updated in Staff 6.55 (Supplemental) Fossil Generation Post-Test Year Plant Additions | | (5) Updated in Staff 6.55 (Supplemental) Nuclear Generation Post-Test Year Plant Additions | | (6) Updated in Staff 6.55 (Supplemental) Distribution and General and Intangibles Post-Test Year Plant Additions | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (G) | ACC (H) | Total Co. (I) | ACC (J) | Total Co. (K) | ACC (L) |
| 1. | Gross Utility Plant in Service | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Less: Accumulated Depreciation & Amort. | - | - | - | - | - | - |
| 3 | Net Utility Plant in Service | - | - | - | - | - | - |
| 4. | Less: Total Deductions | - | - | - | - | - | - |
| 5. | Total Additions | - | - | - | - | - | - |
| 6. | Total Rate Base | $ - | $ - | $ - | $ - | $ - | $ - |

**WITNESS:**

(4) Adjustment to Reverse inclusion of Post-Test Year Plant Additions for fossil generation

(5) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for nuclear generation estimated in service date prior to 6/30/2012.

(6) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for distribution and general and intangibles.

Supporting Schedules
(a) E-1

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| | | (7) Updated to Reflect New Pro Formas Adjust Cash Working Capital for Cost of Service Pro Formas | | (8) Total Original Cost Rate Base Pro Forma Adjustments | | (9) Adjusted at End of Test Year 12/31/2010 | |
|---|---|---|---|---|---|---|---|
| Line No. | Description | Total Co. (M) | ACC (N) | (b) Total Co. (O) | (b) ACC (P) | (b) Total Co. (Q) | (b) ACC (R) |
| 1. | Gross Utility Plant in Service | $ - | $ - | $ 246,932 | $ 238,536 | $ 13,903,037 | $ 11,760,649 |
| 2. | Less: Accumulated Depreciation & Amort. | - | - | 1,958 | 1,892 | 5,220,958 | 4,530,759 |
| 3 | Net Utility Plant in Service | - | - | 244,974 | 236,644 | 8,682,079 | 7,229,890 |
| 4. | Less: Total Deductions | - | - | 1,862 | 1,799 | 3,673,431 | 3,228,630 |
| 5. | Total Additions | (13,482) | (9,357) | (8,935) | (9,357) | 1,660,078 | 1,543,166 |
| 6. | Total Rate Base | $ (13,482) | $ (9,357) | $ 234,177 | $ 225,488 | $ 6,668,726 | $ 5,544,426 |

**WITNESS:** LA BENZ

(7) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study per RUCO Schedules. See RUCO Working Cap Adj - Final.xls

Supporting Schedules
(a) E-1

Recap Schedules:
(b) RUCO B-1

# RUCO Schedule B-3

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (1) Actual at End of Test Year 12/31/2010 (a) Total Co. (A) | ACC (B) | (2) West Phoenix Unit 4 Regulatory Disallowance Total Co. (C) | ACC (D) | (3) **Updated in Staff 6.55 (Supplemental)** Solar Generation Post-Test Year Plant Additions Total Co. (E) | ACC (F) |
|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ 26,378,778 | $ 22,255,775 | $ (13,833) | $ (13,363) | $ 260,765 | $ 251,899 |
| 2. | Less: Accumulated Depreciation & Amort. | 9,826,977 | 8,527,851 | (3,635) | (3,511) | 5,593 | 5,403 |
| 3 | Net Utility Plant in Service | 16,551,801 | 13,727,924 | (10,198) | (9,852) | 255,172 | 246,496 |
| 4. | Less: Total Deductions | 5,798,056 | 4,953,254 | (1,469) | (1,419) | 3,331 | 3,218 |
| 5. | Total Additions | 1,669,013 | 1,552,523 | - | - | - | - |
| 6. | Total Rate Base | $ 12,422,758 | $ 10,327,193 | $ (8,729) | $ (8,433) | $ 251,841 | $ 243,278 |

(1) Test Year Total Deductions and Total Additions are shown on Schedule RUCO B-1.

(2) Adjustment to reduce Test Year rate base for regulatory disallowance for West Phoenix Unit 4 as required in Decisions Nos. 67744 and 69663.

(3) Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in service date prior to 6/30/2012.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (4) Updated in Staff 6.55 (Supplemental) Fossil Generation Post-Test Year Plant Additions | | (5) Updated in Staff 6.55 (Supplemental) Nuclear Generation Post-Test Year Plant Additions | | (6) Updated in Staff 6.55 (Supplemental) Distribution and General and Intangibles Post-Test Year Plant Additions | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (G) | ACC (H) | Total Co. (I) | ACC (J) | Total Co. (K) | ACC (L) |
| 1. | Gross Utility Plant in Service | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Less: Accumulated Depreciation & Amort. | - | - | - | - | - | - |
| 3 | Net Utility Plant in Service | - | - | - | - | - | - |
| 4. | Less: Total Deductions | - | - | - | - | - | - |
| 5. | Total Additions | - | - | - | - | - | - |
| 6. | Total Rate Base | $ - | $ - | $ - | $ - | $ - | $ - |

(4) Adjustment to Reverse inclusion of Post-Test Year Plant Additions for fossil generation

(5) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for nuclear generation estimated in service date prior to 6/30/2012.

(6) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for distribution and general and intangibles.

Supporting Schedules
(a) B-4

Recap Schedules:
(b) RUCO B-1

ARIZONA PUBLIC SERVICE COMPANY
RCND RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (7) Updated to Reflect New Pro Formas Adjust Cash Working Capital for Cost of Service Pro Formas Total Co. (M) | (7) ACC (N) | (8) Total RCND Cost Rate Base Pro Forma Adjustments (b) Total Co. (O) | (8) (b) ACC (P) | (9) Adjusted at End of Test Year 12/31/2010 (b) Total Co. (Q) | (9) (b) ACC (R) |
|---|---|---|---|---|---|---|---|
| 1. | Gross Utility Plant in Service | $ - | $ - | $ 246,932 | $ 238,536 | $ 26,625,710 | $ 22,494,311 |
| 2. | Less: Accumulated Depreciation & Amort. | - | - | 1,958 | 1,892 | 9,828,935 | 8,529,743 |
| 3 | Net Utility Plant in Service | - | - | 244,974 | 236,644 | 16,796,775 | 13,964,568 |
| 4. | Less: Total Deductions | - | - | 1,862 | 1,799 | 5,799,918 | 4,955,053 |
| 5. | Total Additions | (8,935) | (6,201) | (8,935) | (6,201) | 1,660,078 | 1,546,322 |
| 6. | Total Rate Base | $ (8,935) | $ (6,201) | $ 234,177 | $ 228,644 | $ 12,656,935 | $ 10,555,837 |

(7) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study per RUCO Schedules. See RUCO Working Cap Adj - Final.xls

Supporting Schedules
(a) B-4

Recap Schedules:
(b) RUCO B-1

# RUCO Schedule C-1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | Total Company: Actual For The Test Year Ended 12/31/2010 (a) (A) | Proforma Adjustments (b) (B) | Test Year Results After Proforma Adjustments (c) (C) | Line No. |
|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | |
| 1. | Revenues from Base Rates | $ 2,946,463 | $ 10,040 | $ 2,956,503 | 1. |
| 2. | Revenues from Surcharges | 71,530 | (71,530) | - | 2. |
| 3. | Other Electric Revenues | 162,814 | (25,965) | 136,849 | 3. |
| 4. | Total | 3,180,807 | (87,455) | 3,093,352 | 4. |
| | Operating expenses: | | | | |
| 5. | Electric fuel and purchased power | 1,046,815 | (18,292) | 1,028,523 | 5. |
| 6. | Operations and maintenance excluding fuel expenses | 900,372 | (188,348) | 712,024 | 6. |
| 7. | Depreciation and amortization | 406,632 | (22,259) | 384,373 | 7. |
| 8. | Income taxes | 175,440 | 68,598 | 244,038 | 8. |
| 9. | Other taxes | 134,467 | 18,191 | 152,658 | 9. |
| 10. | Total | 2,663,726 | (142,110) | 2,521,616 | 10. |
| 11. | Operating income | 517,081 | 54,655 | 571,736 | 11. |
| | Other income (deductions): | | | | |
| 12. | Income taxes | 4,975 | - | 4,975 | 12. |
| 13. | Allowance for equity funds used during construction | 22,066 | - | 22,066 | 13. |
| 14. | Other income | 8,956 | - | 8,956 | 14. |
| 15. | Other expense | (15,859) | - | (15,859) | 15. |
| 16. | Total | 20,138 | - | 20,138 | 16. |
| 17. | Income before interest deductions | 537,219 | 54,655 | 591,874 | 17. |
| | Interest deductions: | | | | |
| 18. | Interest on long-term debt | 205,209 | - | 205,209 | 18. |
| 19. | Interest on short-term borrowings | 8,267 | - | 8,267 | 19. |
| 20. | Debt discount, premium and expense | 4,559 | - | 4,559 | 20. |
| 21. | Allowance for borrowed funds used during construction | (16,479) | - | (16,479) | 21. |
| 22. | Total | 201,556 | - | 201,556 | 22. |
| 23. | Net income | $ 335,663 | $ 54,655 | $ 390,318 | 23. |

Supporting Schedules:
(a) E-2
(b) RUCO C-2

Recap Schedules:
(c) RUCO A-2

ARIZONA PUBLIC SERVICE COMPANY
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| | | ACC Jurisdiction | | | |
|---|---|---|---|---|---|
| Line No. | Description | Actual For The Test Year Ended 12/31/2010 (A) | Proforma Adjustments (a) (B) | Test Year Results After Proforma Adjustments (b) (C) | Line No. |
| | Electric Operating Revenues | | | | |
| 1. | Revenues from Base Rates | $ 2,862,997 | $ 10,040 | $ 2,873,037 | 1. |
| 2. | Revenues from Surcharges | 71,238 | (83,800) | (12,562) | 2. |
| 3. | Other Electric Revenues | 146,808 | (25,795) | 121,013 | 3. |
| 4. | Total | 3,081,043 | (99,555) | 2,981,488 | 4. |
| | Operating expenses: | | | | |
| 5. | Electric fuel and purchased power | 1,021,577 | (18,272) | 1,003,305 | 5. |
| 6. | Operations and maintenance excluding fuel expenses | 1,000,134 | (187,542) | 812,592 | 6. |
| 7. | Depreciation and amortization | 358,023 | (26,248) | 331,775 | 7. |
| 8. | Income taxes | 150,805 | 62,318 | 213,123 | 8. |
| 9. | Other taxes | 114,221 | 15,415 | 129,636 | 9. |
| 10. | Total | 2,644,760 | (154,329) | 2,490,431 | 10. |
| 11. | Operating income | 436,283 | 54,774 | 491,057 | 11. |
| | Other income (deductions): | | | | |
| 12. | Income taxes | - | - | - | 12. |
| 13. | Allowance for equity funds used during construction | - | - | - | 13. |
| 14. | Other income | - | - | - | 14. |
| 15. | Other expense | - | - | - | 15. |
| 16. | Total | - | - | - | 16. |
| 17. | Income before interest deductions | 436,283 | 54,774 | 491,057 | 17. |
| | Interest deductions: | | | | |
| 18. | Interest on long-term debt | - | - | - | 18. |
| 19. | Interest on short-term borrowings | - | - | - | 19. |
| 20. | Debt discount, premium and expense | - | - | - | 20. |
| 21. | Allowance for borrowed funds used during construction | - | - | - | 21. |
| 22. | Total | - | - | - | 22. |
| 23. | Net income | $ 436,283 | $ 54,774 | $ 491,057 | 23. |

Supporting Schedules:
(a) RUCO C-2

Recap Schedules:
(b) RUCO A-1

ARIZONA PUBLIC SERVICE COMPANY
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | ACC Jurisdiction: Actual For The Test Year Ended 12/31/2010 (A) | Proforma Adjustments (a) (B) | Test Year Results After Proforma Adjustments (b) (C) | Line No. |
|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | |
| 1. | Revenues from Base Rates | $ 2,862,997 | $ 10,040 | $ 2,873,037 | 1. |
| 2. | Revenues from Surcharges | 71,238 | (83,800) | (12,562) | 2. |
| 3. | Other Electric Revenues | 146,808 | (25,795) | 121,013 | 3. |
| 4. | Total | 3,081,043 | (99,555) | 2,981,488 | 4. |
| | Operating expenses: | | | | |
| 5. | Electric fuel and purchased power | 1,021,577 | (18,272) | 1,003,305 | 5. |
| 6. | Operations and maintenance excluding fuel expenses | 1,000,134 | (187,542) | 812,592 | 6. |
| 7. | Depreciation and amortization | 358,023 | (26,248) | 331,775 | 7. |
| 8. | Income taxes | 150,805 | 62,318 | 213,123 | 8. |
| 9. | Other taxes | 114,221 | 15,415 | 129,636 | 9. |
| 10. | Total | 2,644,760 | (154,329) | 2,490,431 | 10. |
| 11. | Operating income | 436,283 | 54,774 | 491,057 | 11. |
| | Other income (deductions): | | | | |
| 12. | Income taxes | - | - | - | 12. |
| 13. | Allowance for equity funds used during construction | - | - | - | 13. |
| 14. | Other income | - | - | - | 14. |
| 15. | Other expense | - | - | - | 15. |
| 16. | Total | - | - | - | 16. |
| 17. | Income before interest deductions | 436,283 | 54,774 | 491,057 | 17. |
| | Interest deductions: | | | | |
| 18. | Interest on long-term debt | - | - | - | 18. |
| 19. | Interest on short-term borrowings | - | - | - | 19. |
| 20. | Debt discount, premium and expense | - | - | - | 20. |
| 21. | Allowance for borrowed funds used during construction | - | - | - | 21. |
| 22. | Total | - | - | - | 22. |
| 23. | Net income | $ 436,283 | $ 54,774 | $ 491,057 | 23. |

Supporting Schedules:
(a) RUCO C-2

Recap Schedules:
(b) RUCO A-1

# RUCO Schedule C-2

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (1) Remove Bark Beetle Remediation Amortization | | (2) Remove Test Year Surcharges and Adjustors | | (3) Include West Phoenix Unit 4 Regulatory Disallowance | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (A) | ACC (B) | Total Co. (C) | ACC (D) | Total Co. (E) | ACC (F) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | (192,761) | (192,469) | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | (192,761) | (192,469) | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | - | (8,201) | (8,201) | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | (184,560) | (184,268) | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | (1,918) | (1,918) | (177,253) | (176,961) | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | (1,918) | (1,918) | (177,253) | (176,961) | - | - |
| 10. | Depreciation and Amortization | | | | | (329) | (318) |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | (1,918) | (1,918) | (177,253) | (176,961) | (329) | (318) |
| 15. | Operating Income Before Income Tax | 1,918 | 1,918 | (7,307) | (7,307) | 329 | 318 |
| 16. | Interest Expense | - | - | - | - | (257) | (248) |
| 17. | Taxable Income | 1,918 | 1,918 | (7,307) | (7,307) | 586 | 566 |
| 18. | Current Income Tax Rate - 39.51% | 758 | 758 | (2,887) | (2,887) | 232 | 224 |
| 19. | Operating Income (line 15 minus line 18) | $ 1,160 | $ 1,160 | $ (4,420) | $ (4,420) | $ 97 | $ 94 |

**WITNESS:** LA BENZ    LA BENZ    LA BENZ

(1) Adjustment to Test Year operations to remove 6-months of deferred bark beetle costs as authorized in *Decision No. 69663.*

(2) Adjustment to Test Year operations to remove the Renewable Energy Standard, Competition Rules Compliance Charge, Demand Side Management, Transmission Cost Adjustor and Regulatory Assessment surcharges from both operating revenues and expenses.

(3) Adjustment to Test Year operations to reflect depreciation of regulatory disallowance of West Phoenix Unit 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| | | (4) | | (5) | | (6) Updated in Staff 6.55 (Supplemental) | |
|---|---|---|---|---|---|---|---|
| | | Include Interest Expense on Customer Deposits | | Adjust Depreciation Expense - 2010 Study | | Solar Generation Post-Test Year Plant Additions | |
| Line No. | Description | Total Co. (G) | ACC (H) | Total Co. (I) | ACC (J) | Total Co. (K) | ACC (L) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | 197 | 197 | - | - | - | - |
| 8. | Maintenance | - | - | - | - | 1,935 | 1,869 |
| 9. | Subtotal | 197 | 197 | - | - | 1,935 | 1,869 |
| 10. | Depreciation and Amortization | | | (28,646) | (32,389) | 8,449 | 8,162 |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | 915 | 884 |
| 14. | Total | 197 | 197 | (28,646) | (32,389) | 11,299 | 10,915 |
| 15. | Operating Income Before Income Tax | (197) | (197) | 28,646 | 32,389 | (11,299) | (10,915) |
| 16. | Interest Expense | | | - | - | 7,404 | 7,152 |
| 17. | Taxable Income | (197) | (197) | 28,646 | 32,389 | (18,703) | (18,067) |
| 18. | Current Income Tax Rate - 39.51% | (78) | (78) | 11,318 | 12,797 | (7,390) | (7,138) |
| 19. | Operating Income (line 15 minus line 18) | $ (119) | $ (119) | $ 17,328 | $ 19,592 | $ (3,909) | $ (3,777) |

**WITNESS:** LA BENZ   LA BENZ   GULDNER / LA BENZ

(4) Adjustment to Test Year operations to reflect the operating income impact of interest on customer deposits using January 2011 interest rates.

(5) Adjustment to Test Year operations to reflect depreciation expense based on the 2010 depreciation study.

(6) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income taxes associated with Solar Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (7) Updated in Staff 6.55 (Supplemental) Fossil Generation Post-Test Year Plant Additions | | (8) Updated in Staff 6.55 (Supplemental) Nuclear Generation Post-Test Year Plant Additions | | (9) Updated in Staff 6.55 (Supplemental) Distribution and General and Intangible Post-Test Year Plant Additions | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (M) | ACC (N) | Total Co. (O) | ACC (P) | Total Co. (Q) | ACC (R) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | | - | - |
| 3. | Other Electric Revenues | - | - | - | | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | - | - | - | - |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | - | - | - | - | - | - |
| 15. | Operating Income Before Income Tax | - | - | - | - | - | - |
| 16. | Interest Expense | - | - | - | - | - | - |
| 17. | Taxable Income | - | - | - | - | - | - |
| 18. | Current Income Tax Rate - 39.51% | - | - | - | - | - | - |
| 19. | Operating Income (line 15 minus line 18) | $ - | $ - | $ - | $ - | $ - | $ - |
| | **WITNESS:** | RUCO - RADIGAN | | RUCO - RADIGAN | | RUCO - RADIGAN | |

(7) Adjustment to Reverse inclusion of Post-Test Year Plant Additions for fossil generation

(8) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for nuclear generation estimated in service date prior to 6/30/2012.

(9) Adjustment to Reverse Inclusion of Post-Test Year Plant Additions for distribution and general and intangibles.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (10) Decommissioning and Spent Fuel Costs Total Co. (S) | ACC (T) | (11) Updated to Reflect New Union Contract Annualize Payroll Expense Total Co. (U) | ACC (V) | (12) Normalize Employee Benefits Total Co. (W) | ACC (X) |
|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | (4,236) | (4,133) | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | 4,236 | 4,133 | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | 3,795 | 3,527 | 8,148 | 7,572 |
| 8. | Maintenance | - | - | 1,060 | 985 | - | - |
| 9. | Subtotal | - | - | 4,855 | 4,512 | 8,148 | 7,572 |
| 10. | Depreciation and Amortization | (2,947) | (2,875) | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | (2,947) | (2,875) | 4,855 | 4,512 | 8,148 | 7,572 |
| 15. | Operating Income Before Income Tax | 7,183 | 7,008 | (4,855) | (4,512) | (8,148) | (7,572) |
| 16. | Interest Expense | - | - | - | - | - | - |
| 17. | Taxable Income | 7,183 | 7,008 | (4,855) | (4,512) | (8,148) | (7,572) |
| 18. | Current Income Tax Rate - 39.51% | 2,838 | 2,769 | (1,918) | (1,783) | (3,219) | (2,992) |
| 19. | Operating Income (line 15 minus line 18) | $ 4,345 | $ 4,239 | $ (2,937) | $ (2,729) | $ (4,929) | $ (4,580) |
| | **WITNESS:** | LA BENZ | | LA BENZ | | LA BENZ | |

(10) Adjustment to Test Year operations to reflect updated decommissioning funding levels for Palo Verde due to license extension and updated ISFSI expense.

(11) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2011 employee levels, March 2011 wage levels for performance review employees and 2012 wage levels for Union employees.

(12) Adjustment to Test Year operations to reflect the current December 2010 actuarial valuation of retirement program expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (13) Normalize Income Tax Expense/Interest Synchronization | | (14) Reflects Most Current Property Tax Rates — Annualize Property Tax Expense | | (15) Annualize Severance Costs | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (Y) | ACC (Z) | Total Co. (AA) | ACC (BB) | Total Co. (CC) | ACC (DD) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | (6,732) | (6,256) |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | - | - | (6,732) | (6,256) |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | 17,276 | 14,531 | - | - |
| 14. | Total | - | - | 17,276 | 14,531 | (6,732) | (6,256) |
| 15. | Operating Income Before Income Tax | - | - | (17,276) | (14,531) | 6,732 | 6,256 |
| 16. | Interest Expense | (57,259) | (47,357) | - | - | - | - |
| 17. | Taxable Income | 57,259 | 47,357 | (17,276) | (14,531) | 6,732 | 6,256 |
| 18. | Current Income Tax Rate - 39.51% | 22,623 | 18,711 | (6,826) | (5,741) | 2,660 | 2,472 |
| 19. | Operating Income (line 15 minus line 18) | $ (22,623) | $ (18,711) | $ (10,450) | $ (8,790) | $ 4,072 | $ 3,784 |
| | **WITNESS:** | RUCO - RADIGAN | | LA BENZ | | LA BENZ | |

(13) Adjustment to Test Year operations for income tax true-ups consistent with Staff method in 2008 APS Rate CASe

(14) Adjustment to Test Year operations to annualize property taxes calculated using the actual 2011 tax assessment ratio and tax rate.

(15) Adjustment to Test Year operations to amortize the expense associated with employees severed in 2010 over a three year period.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (16) Amortize Childs-Irving Excess Decommissioning Costs | | (17) Remove Schedule 3 Revenues | | (18) Normalize Fossil Maintenance | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (EE) | ACC (FF) | Total Co. (GG) | ACC (HH) | Total Co. (II) | ACC (JJ) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | (18,660) | (18,660) | - | |
| 4. | Total Electric Operating Revenues | - | - | (18,660) | (18,660) | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | (18,660) | (18,660) | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 8. | Maintenance | - | - | - | - | (4,397) | (4,290) |
| 9. | Subtotal | - | - | - | - | (4,397) | (4,290) |
| 10. | Depreciation and Amortization | (893) | (863) | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | (893) | (863) | - | - | (4,397) | (4,290) |
| 15. | Operating Income Before Income Tax | 893 | 863 | (18,660) | (18,660) | 4,397 | 4,290 |
| 16. | Interest Expense | - | - | - | - | - | - |
| 17. | Taxable Income | 893 | 863 | (18,660) | (18,660) | 4,397 | 4,290 |
| 18. | Current Income Tax Rate - 39.51% | 353 | 341 | (7,373) | (7,373) | 1,737 | 1,695 |
| 19. | Operating Income (line 15 minus line 18) | $ 540 | $ 522 | $ (11,287) | $ (11,287) | $ 2,660 | $ 2,595 |
| | **WITNESS:** | LA BENZ | | RUCO - Radigan | | LA BENZ | |

(16) Adjustment to amortize the excess decommissioning costs for the Childs Irving Power Plant over a three year period.

(17) Reverse Adjustment to remove revenues associated with Schedule 3 in the Test Year.

(18) Adjustment to Test Year operations to reflect normalization of fossil production maintenance expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| | | (19) | | (20) | | (21) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Updated to Reflect New Pro Formas | |
| | | Normalize Nuclear Maintenance | | Annualize Four Corners Coal Reclamation Costs | | Adjust Cash Working Capital for Cost of Service Pro Formas | |
| Line No. | Description | Total Co. (KK) | ACC (LL) | Total Co. (MM) | ACC (NN) | Total Co. (OO) | ACC (PP) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | - | - | - | - |
| 5. | Electric Fuel and Purchased Power Costs | - | - | 3,430 | 3,347 | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | (3,430) | (3,347) | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | - | - | - | - |
| 8. | Maintenance | 5,383 | 5,252 | - | - | - | - |
| 9. | Subtotal | 5,383 | 5,252 | - | - | - | - |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | 5,383 | 5,252 | - | - | - | - |
| 15. | Operating Income Before Income Tax | (5,383) | (5,252) | (3,430) | (3,347) | - | - |
| 16. | Interest Expense | - | - | - | - | (257) | (179) |
| 17. | Taxable Income | (5,383) | (5,252) | (3,430) | (3,347) | 257 | 179 |
| 18. | Current Income Tax Rate - 39.51% | (2,127) | (2,075) | (1,355) | (1,322) | 102 | 71 |
| 19. | Operating Income (line 15 minus line 18) | $ (3,256) | $ (3,177) | $ (2,075) | $ (2,025) | $ (102) | $ (71) |
| | WITNESS: | LA BENZ | | RUCO - Radigan | | LA BENZ | |

(19) Adjustment to Test Year operations to reflect normalization of nuclear production maintenance expense.

(20) Adjustment to APS Presentation refjecting 4 yr amortization of Four Corner Service Life of Units 1-3.

(21) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment, as shown on Schedule RUCO B-2, page 3, column 7.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (22) Remove PWEC Loan Amortization Total Co. (QQ) | ACC (RR) | (23) Amortize Pension and OPEB Deferral Total Co. (SS) | ACC (TT) | (24) Normalize Pole Attachment Revenues Total Co. (UU) | ACC (VV) |
|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | (305) | (305) |
| 4. | Total Electric Operating Revenues | - | - | - | - | (305) | (305) |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | (305) | (305) |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | 8,740 | 8,122 | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | 8,740 | 8,122 | - | - |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | 2,107 | 2,035 | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | 2,107 | 2,035 | 8,740 | 8,122 | - | - |
| 15. | Operating Income Before Income Tax | (2,107) | (2,035) | (8,740) | (8,122) | (305) | (305) |
| 16. | Interest Expense | - | - | - | - | - | - |
| 17. | Taxable Income | (2,107) | (2,035) | (8,740) | (8,122) | (305) | (305) |
| 18. | Current Income Tax Rate - 39.51% | (832) | (804) | (3,453) | (3,209) | (121) | (121) |
| 19. | Operating Income (line 15 minus line 18) | $ (1,275) | $ (1,231) | $ (5,287) | $ (4,913) | $ (184) | $ (184) |
| | **WITNESS:** | LA BENZ | | LA BENZ | | LA BENZ | |

(22) Adjustment to Test Year operations to remove PWEC loan amortization and interest authorized in Decision No. 65796 and 67744.

(23) Adjustment to Test Year operations reflect the recovery of the Pension/OPEB deferral authorized in Decision No. 71448 to be amortized over a three year period.

(24) Adjustment to Test Year Other Electric Revenues to reflect change in FCC rules impacting pole attachment fees.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| | | (25) | | (26) | | (27) | |
|---|---|---|---|---|---|---|---|
| | | Remove Supplemental Executive Retirement Plan Benefits | | Remove Stock Compensation | | Remove Out of Period and Miscellaneous Items | |
| Line No. | Description | Total Co. (WW) | ACC (XX) | Total Co. (YY) | ACC (ZZ) | Total Co. (AAA) | ACC (BBB) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | (7,000) | (6,830) |
| 4. | Total Electric Operating Revenues | - | - | - | - | (7,000) | (6,830) |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | (7,000) | (6,830) |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | (8,492) | (7,892) | (12,421) | (11,543) | 3,000 | 2,996 |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | (8,492) | (7,892) | (12,421) | (11,543) | 3,000 | 2,996 |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | (2,529) | (2,350) |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | (8,492) | (7,892) | (12,421) | (11,543) | 471 | 646 |
| 15. | Operating Income Before Income Tax | 8,492 | 7,892 | 12,421 | 11,543 | (7,471) | (7,476) |
| 16. | Interest Expense | - | - | - | - | - | - |
| 17. | Taxable Income | 8,492 | 7,892 | 12,421 | 11,543 | (7,471) | (7,476) |
| 18. | Current Income Tax Rate - 39.51% | 3,355 | 3,118 | 4,908 | 4,561 | (2,952) | (2,954) |
| 19. | Operating Income (line 15 minus line 18) | $ 5,137 | $ 4,774 | $ 7,513 | $ 6,982 | $ (4,519) | $ (4,522) |
| | **WITNESS:** | LA BENZ | | LA BENZ | | LA BENZ | |

(25) Adjustment to Test Year operations to remove supplemental executive retirement benefits ("SERP").

(26) Adjustment to Test Year operations to remove stock compensation.

(27) Adjustment to Test Year operations to remove legal accrual reserve, bad debt reversal accrual, grant reserve, benchmark study costs, branding costs and a non-recurring payroll expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (28) Updated in Staff 22.9 (Supplemental) Base Fuel and Purchased Power | | (29) Test Year PSA Revenue and Deferred Fuel Amortization | | (30) Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals | |
|---|---|---|---|---|---|---|---|
| | | Total Co. (CCC) | ACC (DDD) | Total Co. (EEE) | ACC (FFF) | Total Co. (GGG) | ACC (HHH) |
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ - | $ - |
| 2. | Revenues from Surcharges | - | - | 121,231 | 108,669 | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | - | - | 121,231 | 108,669 | - | - |
| 5. | Electric Fuel and Purchased Power Costs | (39,385) | (39,385) | 127,728 | 127,728 | (101,790) | (101,790) |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | 39,385 | 39,385 | (6,497) | (19,059) | 101,790 | 101,790 |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | - | - | (6,497) | (6,497) | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | (6,497) | (6,497) | - | - |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | - | - | (6,497) | (6,497) | - | - |
| 15. | Operating Income Before Income Tax | 39,385 | 39,385 | - | (12,562) | 101,790 | 101,790 |
| 16. | Interest Expense | - | - | - | - | - | - |
| 17. | Taxable Income | 39,385 | 39,385 | - | (12,562) | 101,790 | 101,790 |
| 18. | Current Income Tax Rate - 39.51% | 15,561 | 15,561 | - | (4,963) | 40,217 | 40,217 |
| 19. | Operating Income (line 15 minus line 18) | $ 23,824 | $ 23,824 | $ - | $ (7,599) | $ 61,573 | $ 61,573 |
| | **WITNESS:** | EWEN | | EWEN | | EWEN | |

(28) Adjustment to Test Year Operations to include 2012 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

(29) Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods.

(30) Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and mark-to-market accruals.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (31) Normalize Weather Conditions Total Co. (III) | ACC (JJJ) | (32) Annualize Customer Levels Total Co. (KKK) | ACC (LLL) | (33) Low Income Customer Discount Total Co. (MMM) | ACC (NNN) |
|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ 10,330 | $ 10,330 | $ (290) | $ (290) | $ - | $ - |
| 2. | Revenues from Surcharges | | | - | - | - | - |
| 3. | Other Electric Revenues | - | - | - | - | - | - |
| 4. | Total Electric Operating Revenues | 10,330 | 10,330 | (290) | (290) | - | - |
| 5. | Electric Fuel and Purchased Power Costs | 3,909 | 3,909 | 253 | 253 | - | - |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | 6,421 | 6,421 | (543) | (543) | - | - |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | | | - | - | - | - |
| 8. | Maintenance | - | - | - | - | - | - |
| 9. | Subtotal | - | - | - | - | - | - |
| 10. | Depreciation and Amortization | - | - | - | - | - | - |
| 11. | Amortization of Gain | - | - | - | - | - | - |
| 12. | Administrative and General | - | - | - | - | - | - |
| 13. | Other Taxes | - | - | - | - | - | - |
| 14. | Total | - | - | - | - | - | - |
| 15. | Operating Income Before Income Tax | 6,421 | 6,421 | (543) | (543) | - | - |
| 16. | Interest Expense | - | - | - | - | - | - |
| 17. | Taxable Income | 6,421 | 6,421 | (543) | (543) | - | - |
| 18. | Current Income Tax Rate - 39.51% | 2,537 | 2,537 | (215) | (215) | - | - |
| 19. | Operating Income (line 15 minus line 18) | $ 3,884 | $ 3,884 | $ (328) | $ (328) | $ - | $ - |

**WITNESS:** MIESSNER | MIESSNER | RUCO - Radigan

(31) Adjustment to Test Year operations to reflect normal weather conditions for the ten years ended December 31, 2010.

(32) Adjustment to Test Year operations to reflect the annualization of customer levels at December 31, 2010.

(33) Reject APS Adjustment to Test Year operations to reflect the increase in low income customer discounts from the Test Year through July 2012.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

| Line No. | Description | (34) Removal per Staff 9.2 — Exclude Certain R&D Project Expenses — Total Co. (OOO) | ACC (PPP) | (35) Updated to Sync with FERC Filing — Sync Step-Up Transformer Costs Excluded with FERC Formula Rate — Total Co. (QQQ) | ACC (RRR) | (36) Total Income Statement Adjustments (a) — Total Co. (SSS) | ACC (TTT) |
|---|---|---|---|---|---|---|---|
| | Electric Operating Revenues | | | | | | |
| 1. | Revenues from Base Rates | $ - | $ - | $ - | $ - | $ 10,040 | $ 10,040 |
| 2. | Revenues from Surcharges | - | - | - | - | (71,530) | (83,800) |
| 3. | Other Electric Revenues | - | - | - | - | (25,965) | (25,795) |
| 4. | Total Electric Operating Revenues | - | - | - | - | (87,455) | (99,555) |
| 5. | Electric Fuel and Purchased Power Costs | - | - | - | - | (18,292) | (18,272) |
| 6. | Oper Rev Less Fuel & Purch Pwr Costs | - | - | - | - | (69,163) | (81,283) |
| | Other Operating Expenses: | | | | | | |
| 7. | Operations Excluding Fuel Expense | (2,129) | (2,057) | 1,762 | 1,702 | (189,800) | (189,008) |
| 8. | Maintenance | - | - | - | - | 3,981 | 3,816 |
| 9. | Subtotal | (2,129) | (2,057) | 1,762 | 1,702 | (185,819) | (185,192) |
| 10. | Depreciation and Amortization | - | - | - | - | (24,366) | (28,283) |
| 11. | Amortization of Gain | - | - | - | - | 2,107 | 2,035 |
| 12. | Administrative and General | - | - | - | - | (2,529) | (2,350) |
| 13. | Other Taxes | - | - | - | - | 18,191 | 15,415 |
| 14. | Total | (2,129) | (2,057) | 1,762 | 1,702 | (192,416) | (198,375) |
| 15. | Operating Income Before Income Tax | 2,129 | 2,057 | (1,762) | (1,702) | 123,253 | 117,092 |
| 16. | Interest Expense | - | - | - | - | (50,369) | (40,632) |
| 17. | Taxable Income | 2,129 | 2,057 | (1,762) | (1,702) | 173,622 | 157,724 |
| 18. | Current Income Tax Rate - 39.51% | 841 | 813 | (696) | (672) | 68,598 | 62,318 |
| 19. | Operating Income (line 15 minus line 18) | $ 1,288 | $ 1,244 | $ (1,066) | $ (1,030) | $ 54,655 | $ 54,774 |
| | **WITNESS:** | GULDNER | | FRYER | | | |

(34) Adjustment to Test Year operations to remove costs associated certain R&D projects.

(35) Adjustment to Test Year operations to sync up the step-up transformers excluded from the FERC formula rate.

Supporting Schedules:
N/A

Recap Schedules:
(a) RUCO C-1

# RUCO Fair Value Increment

# Calculation of Fair Value Increment

| | *Adjusted Test Year Capital Structure* | | Amount | % | Cost Rate | Weighted Avg |
|---|---|---|---|---|---|---|
| 1. | Long-Term Debt | $ | 3,382,856 | 46.06% | 6.26% | 2.88% |
| 2. | Preferred Stock | | - | 0.00% | 0.00% | 0.00% |
| 3. | Common Equity | | 3,961,248 | 53.94% | 10.00% | 5.39% |
| 4. | Short-Term Debt | | - | 0.00% | 0.00% | 0.00% |
| 5. | Total | $ | 7,344,104 | 100.00% | | 8.27% |

| | *Capital Structure with 1.5% FV Increment* | | Amount | % | Cost Rate | Weighted Avg |
|---|---|---|---|---|---|---|
| 6. | Long-Term Debt | $ | 3,382,856 | 46.06% | 4.08% | 1.88% |
| 7. | Preferred Stock | | - | 0.00% | 0.00% | 0.00% |
| 8. | Common Equity | | 3,961,248 | 53.94% | 7.82% | 4.22% |
| 9. | Short-Term Debt | | - | 0.00% | 0.00% | 0.00% |
| 10. | FVRB Increment | | - | 0.00% | 0.00% | 0.00% |
| 11. | Total | $ | 7,344,104 | 100.00% | | 6.10% |

| | *Fair Value Increment Calculation* | | Fair Value | | Original Cost |
|---|---|---|---|---|---|
| 12. | Rate Base | $ | 8,050,131 | $ | 5,544,426 |
| 13. | Rate of Return | | 6.10% | | 8.27% |
| 14. | Required Operating Income | $ | 491,058 | $ | 458,524 |
| 15. | Adjusted Operating Income | $ | 491,057 | $ | 491,057 |
| 16. | Adjusted Operating Income Deficiency (line 14 - line 15) | $ | 1 | $ | (32,533) |
| 17. | Revenue Conversion Factor | | 1.6532 | | 1.6532 |
| 18. | Increase in Base Revenue Requirements (line 16 * line 17) | $ | (0) | $ | (53,785) |
| 19. | Fair Value Increment | $ | 53,784 | | |

# RUCO Cash Working Capital

# Adjustment

ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

| LINE | DESCRIPTION | 1 Remove Bark Beetle Remediation Amortization | 2 Remove Test Year Surcharges | 3 Include West Phoenix Unit 4 Regulatory Disallowance | 4 Include Interest Expense on Customer Deposits | 5 Adjust Depreciation Expense -2010 Study | 6 Solar Generation Post-Test Year Plant Additions | 7 Fossil Generation Post-Test Year Plant Additions | 8 Nuclear Generation Post-Test Year Plant Additions | 9 Distribution and General and Intangible Post-Test Year Plant Additions | 10 Decommissioning and Spent Fuel Costs | 11 Annual Payroll Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total Co. (A) | Total Co. (C) | Total Co. (E) | Total Co. (G) | Total Co. (I) | Total Co. (K) | Total Co. (M) | Total Co. (O) | Total Co. (Q) | Total Co. (S) | Total Co. (U) |
| 1 | FUEL FOR ELECTRIC GENERATION: | | | | | | | | | | | |
| 2 | COAL | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 3 | NATURAL GAS | - | - | - | - | - | - | - | - | - | - | - |
| 4 | GAS MTM AND FUTURES | - | - | - | - | - | - | - | - | - | - | - |
| 5 | HANDLING | - | - | - | - | - | - | - | - | - | - | - |
| 6 | FUEL OIL | - | - | - | - | - | - | - | - | - | - | - |
| 7 | NUCLEAR: | | | | | | | | | | | |
| 8 | AMORTIZATION | - | - | - | - | - | - | - | - | - | - | - |
| 9 | SPENT FUEL | - | - | - | - | - | - | - | - | - | (4,236) | - |
| 10 | TOTAL NUCLEAR FUEL | - | - | - | - | - | - | - | - | - | (4,236) | - |
| 11 | | | | | | | | | | | | |
| 12 | TOTAL FUEL | - | - | - | - | - | - | - | - | - | (4,236) | - |
| 13 | | | | | | | | | | | | |
| 14 | PURCHASED POWER | - | (8,201) | - | - | - | - | - | - | - | - | - |
| 15 | POWER MTM | - | - | - | - | - | - | - | - | - | - | - |
| 16 | POWER SUPPLY ADJUSTER | - | - | - | - | - | - | - | - | - | - | - |
| 17 | TRANSMISSION BY OTHERS | - | - | - | - | - | - | - | - | - | - | - |
| 18 | TOTAL PURCHASED POWER & TRANS | - | (8,201) | - | - | - | - | - | - | - | - | - |
| 19 | | | | | | | | | | | | |
| 20 | TOTAL FUEL AND PURCHASED POWEI | - | (8,201) | - | - | - | - | - | - | - | (4,236) | - |
| 21 | | | | | | | | | | | | |
| 22 | OTHER OPERATIONS & MAINTENANCE: | | | | | | | | | | | |
| 23 | PAYROLL | - | - | - | - | - | 1,935 | - | - | - | - | 4,855 |
| 24 | INCENTIVE | - | - | - | - | - | - | - | - | - | - | - |
| 25 | STOCK COMPENSATION | - | - | - | - | - | - | - | - | - | - | - |
| 26 | SEVERANCE (EXCLUDES PENSION) | - | - | - | - | - | - | - | - | - | - | - |
| 27 | PENSION AND OPEB | - | - | - | - | - | - | - | - | - | - | - |
| 28 | EMPLOYEE BENEFITS | - | - | - | - | - | - | - | - | - | - | - |
| 29 | PAYROLL TAXES | - | - | - | - | - | - | - | - | - | - | - |
| 30 | MATERIALS & SUPPLIES | - | - | - | - | - | - | - | - | - | - | - |
| 31 | VEHICLE LEASE PAYMENTS | - | - | - | - | - | - | - | - | - | - | - |
| 32 | PREPAID VEHICLE LICENSES | - | - | - | - | - | - | - | - | - | - | - |
| 33 | RENTS | - | - | - | - | - | - | - | - | - | - | - |
| 34 | PREPAID RENTS | - | - | - | - | - | - | - | - | - | - | - |
| 35 | PALO VERDE LEASE | - | - | - | - | - | - | - | - | - | - | - |
| 36 | PALO VERDE S/L GAIN AMORT | - | - | - | - | - | - | - | - | - | - | - |
| 37 | INSURANCE | - | - | - | - | - | - | - | - | - | - | - |
| 38 | OTHER | (1,918) | (177,253) | - | 197 | - | - | - | - | - | - | - |
| 39 | TOTAL | (1,918) | (177,253) | - | 197 | - | 1,935 | - | - | - | - | 4,855 |
| 40 | | | | | | | | | | | | |
| 41 | DEPRECIATION & AMORTIZATION | - | - | (329) | - | (28,646) | 8,449 | - | - | - | (2,847) | - |
| 42 | AMORT OF PROP LOSSES & REG STUI | - | - | - | - | - | - | - | - | - | - | - |
| 43 | TOTAL | - | - | (329) | - | (28,646) | 8,449 | - | - | - | (2,947) | - |
| 44 | | | | | | | | | | | | |
| 45 | INCOME TAXES: | | | | | | | | | | | |
| 46 | CURRENT: | | | | | | | | | | | |
| 47 | FEDERAL | - | (2,380) | - | (64) | - | (3,340) | - | - | - | - | (1,581) |
| 48 | STATE | - | (507) | - | (14) | - | (711) | - | - | - | - | (337) |
| 49 | DEFERRED | 758 | - | 232 | - | 11,318 | (3,338) | - | - | - | 2,838 | - |
| 50 | TOTAL | 758 | (2,887) | 232 | (78) | 11,318 | (7,389) | - | - | - | 2,838 | (1,918) |
| 51 | | | | | | | | | | | | |
| 52 | OTHER TAXES: | | | | | | | | | | | |
| 53 | PROPERTY TAXES | - | - | - | - | - | 915 | - | - | - | - | - |
| 54 | SALES TAXES | - | - | - | - | - | - | - | - | - | - | - |
| 55 | FRANCHISE TAXES | - | - | - | - | - | - | - | - | - | - | - |
| 56 | TOTAL | - | - | - | - | - | 915 | - | - | - | - | - |
| 57 | | | | | | | | | | | | |
| 58 | INTEREST EXPENSE - SYNCHRONIZEC | - | - | (257) | - | - | 7,404 | - | - | - | - | - |
| 59 | | | | | | | | | | | | |
| 60 | TOTAL | $ (1,160) | $ (188,341) | $ (354) | $ 119 | $ (17,328) | $ 11,314 | $ - | $ - | $ - | $ (4,345) | $ 2,937 |

ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

| LINE | DESCRIPTION | 12 Normalize Employee Benefits | 13 Normalize Income Tax Expense/Interest Synchronization | 14 Annualize Property Tax Expense | 15 Severance Amortization | 16 Amortize Childs Irving Excess Decommissioning Costs | 17 Remove Schedule 3 Revenues | 18 Normalize Fossil Maintenance | 19 Normalize Nuclear Maintenance | 20 Annualize Four Corners Coal Reclamation Costs | 21 Adjust Cash Working Capital for Cost of Service Pro Formas | 22 Remove PWEC Loan Amortization | 23 Amortize Pension and OPEB Deferral | 24 Normalize Pole Attachment Revenues |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total Co. (W) | Total Co. (Y) | Total Co. (AA) | Total Co. (CC) | Total Co. (EE) | Total Co. (GG) | Total Co. (II) | Total Co. (KK) | Total Co. (MM) | Total Co. (OO) | Total Co. (QQ) | Total Co. (SS) | Total Co. (UU) |
| 1 | FUEL FOR ELECTRIC GENERATION: | | | | | | | | | | | | | |
| 2 | COAL | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,430 | $ - | $ - | $ - | $ - |
| 3 | NATURAL GAS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | GAS MTM AND FUTURES | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | HANDLING | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | FUEL OIL | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | NUCLEAR: | | | | | | | | | | | | | |
| 8 | AMORTIZATION | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | SPENT FUEL | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | TOTAL NUCLEAR FUEL | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 11 | | | | | | | | | | | | | | |
| 12 | TOTAL FUEL | - | - | - | - | - | - | - | - | 3,430 | - | - | - | - |
| 13 | | | | | | | | | | | | | | |
| 14 | PURCHASED POWER | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | POWER MTM | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | POWER SUPPLY ADJUSTER | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 17 | TRANSMISSION BY OTHERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 18 | TOTAL PURCHASED POWER & TRANS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | | | | | | | | | | | | | | |
| 20 | TOTAL FUEL AND PURCHASED POWEI | - | - | - | - | - | - | - | - | 3,430 | - | - | - | - |
| 21 | | | | | | | | | | | | | | |
| 22 | OTHER OPERATIONS & MAINTENANCE | | | | | | | | | | | | | |
| 23 | PAYROLL | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 24 | INCENTIVE | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | STOCK COMPENSATION | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 26 | SEVERANCE (EXCLUDES PENSION) | - | - | - | (6,732) | - | - | - | - | - | - | - | - | - |
| 27 | PENSION AND OPEB | 8,148 | - | - | - | - | - | - | - | - | - | - | 8,740 | - |
| 28 | EMPLOYEE BENEFITS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 29 | PAYROLL TAXES | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 30 | MATERIALS & SUPPLIES | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31 | VEHICLE LEASE PAYMENTS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 32 | PREPAID VEHICLE LICENSES | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 33 | RENTS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 34 | PREPAID RENTS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 35 | PALO VERDE LEASE | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 36 | PALO VERDE S/L GAIN AMORT | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 37 | INSURANCE | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 38 | OTHER | - | - | - | - | - | - | (4,397) | 5,383 | - | - | - | - | - |
| 39 | TOTAL | 8,148 | - | - | (6,732) | - | - | (4,397) | 5,383 | - | - | - | 8,740 | - |
| 40 | | | | | | | | | | | | | | |
| 41 | DEPRECIATION & AMORTIZATION | - | - | - | - | (893) | - | - | - | - | - | 2,107 | - | - |
| 42 | AMORT OF PROP LOSSES & REG STUI | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 43 | TOTAL | - | - | - | - | (893) | - | - | - | - | - | 2,107 | - | - |
| 44 | | | | | | | | | | | | | | |
| 45 | INCOME TAXES: | | | | | | | | | | | | | |
| 46 | CURRENT: | | | | | | | | | | | | | |
| 47 | FEDERAL | - | 19,592 | (5,628) | 1,541 | - | - | 1,432 | (1,754) | - | 129 | - | - | (100) |
| 48 | STATE | - | 4,170 | (1,198) | 328 | - | - | 305 | (373) | - | 27 | - | - | (21) |
| 49 | DEFERRED | (3,219) | - | - | 791 | 353 | - | - | - | (1,355) | - | (832) | (3,453) | - |
| 50 | TOTAL | (3,219) | 23,762 | (6,826) | 2,660 | 353 | - | 1,737 | (2,127) | (1,355) | 156 | (832) | (3,453) | (121) |
| 51 | | | | | | | | | | | | | | |
| 52 | OTHER TAXES: | | | | | | | | | | | | | |
| 53 | PROPERTY TAXES | - | - | 17,276 | - | - | - | - | - | - | - | - | - | - |
| 54 | SALES TAXES | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 55 | FRANCHISE TAXES | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 56 | TOTAL | - | - | 17,276 | - | - | - | - | - | - | - | - | - | - |
| 57 | | | | | | | | | | | | | | |
| 58 | INTEREST EXPENSE - SYNCHRONIZEC | - | (60,142) | - | - | - | - | - | - | - | (396) | - | - | - |
| 59 | | | | | | | | | | | | | | |
| 60 | TOTAL | $ 4,929 | $ (36,380) | $ 10,450 | $ (4,072) | $ (540) | $ - | $ (2,660) | $ 3,256 | $ 2,075 | $ (240) | $ 1,275 | $ 5,287 | $ (121) |

ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

| LINE | DESCRIPTION | 25 Remove Supplemental Executive Retirement Plan Benefits | 26 Remove Stock Compensation | 27 Remove Out of Period and Miscellaneous Items | 28 Base Fuel and Purchased Power | 29 Test Year PSA Revenue and Deferred Fuel Amortization | 30 Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals | 31 Normalize Weather Conditions | 32 Annualize Customer Levels | 33 Low Income Customer Discount | 34 Exclude R&D Project Expenses | 35 Sync Step-Up Transformer Costs Excluded with FERC Formula Rate | 36 Total Income Statement Adjustments (a) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total Co. (WW) | Total Co. (YY) | Total Co. (AAA) | Total Co. (CCC) | Total Co. (EEE) | Total Co. (GGG) | Total Co. (III) | Total Co. (KKK) | Total Co. (MMM) | Total Co. (MMM) | Total Co. (MMM) | Total Co. (OOO) |
| 1 | FUEL FOR ELECTRIC GENERATION: | | | | | | | | | | | | |
| 2 | COAL | $ - | $ - | $ - | $ 45,258 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 48,668 |
| 3 | NATURAL GAS | | | - | (83,112) | - | - | 3,909 | 253 | - | - | - | (78,950) |
| 4 | GAS MTM AND FUTURES | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | HANDLING | - | - | - | (139) | - | - | - | - | - | - | - | (139) |
| 6 | FUEL OIL | - | - | - | - | | | | | - | - | - | - |
| 7 | NUCLEAR: | | | | | | | | | | | | |
| 8 | AMORTIZATION | - | - | - | 9,714 | - | - | - | - | - | - | - | 9,714 |
| 9 | SPENT FUEL | - | - | - | - | - | - | - | - | - | - | - | (4,236) |
| 10 | TOTAL NUCLEAR FUEL | - | - | - | 9,714 | - | - | - | - | - | - | - | 5,478 |
| 11 | | | | | | | | | | | | | - |
| 12 | TOTAL FUEL | - | - | - | (28,279) | - | - | 3,909 | 253 | - | - | - | (24,923) |
| 13 | | | | | | | | | | | | | |
| 14 | PURCHASED POWER | - | - | - | (16,533) | - | - | - | - | - | - | - | (24,734) |
| 15 | POWER MTM | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | POWER SUPPLY ADJUSTER | - | - | - | - | 115,166 | (101,790) | - | - | - | - | - | 13,376 |
| 17 | TRANSMISSION BY OTHERS | - | - | - | 5,427 | - | - | - | - | - | - | - | 5,427 |
| 18 | TOTAL PURCHASED POWER & TRANS | - | - | - | (11,106) | 115,166 | (101,790) | - | - | - | - | - | (5,931) |
| 19 | | | | | | | | | | | | | |
| 20 | TOTAL FUEL AND PURCHASED POWE | - | - | - | (39,385) | 115,166 | (101,790) | 3,909 | 253 | - | - | - | (30,854) |
| 21 | | | | | | | | | | | | | |
| 22 | OTHER OPERATIONS & MAINTENANCE | | | | | | | | | | | | |
| 23 | PAYROLL | - | - | - | - | - | - | - | - | - | - | - | 6,790 |
| 24 | INCENTIVE | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | STOCK COMPENSATION | - | (12,421) | - | - | - | - | - | - | - | - | - | (12,421) |
| 26 | SEVERANCE (EXCLUDES PENSION) | - | - | - | - | - | - | - | - | - | - | - | (6,732) |
| 27 | PENSION AND OPEB | (8,492) | - | - | - | - | - | - | - | - | - | - | 8,396 |
| 28 | EMPLOYEE BENEFITS | - | - | - | - | - | - | - | - | - | - | - | - |
| 29 | PAYROLL TAXES | - | - | - | - | - | - | - | - | - | - | - | - |
| 30 | MATERIALS & SUPPLIES | - | - | - | - | - | - | - | - | - | - | - | - |
| 31 | VEHICLE LEASE PAYMENTS | - | - | - | - | - | - | - | - | - | - | - | - |
| 32 | PREPAID VEHICLE LICENSES | - | - | - | - | - | - | - | - | - | - | - | - |
| 33 | RENTS | - | - | - | - | - | - | - | - | - | - | - | - |
| 34 | PREPAID RENTS | - | - | - | - | - | - | - | - | - | - | - | - |
| 35 | PALO VERDE LEASE | - | - | - | - | - | - | - | - | - | - | - | - |
| 36 | PALO VERDE S/L GAIN AMORT | - | - | - | - | - | - | - | - | - | - | - | - |
| 37 | INSURANCE | - | - | - | - | - | - | - | - | - | - | - | - |
| 38 | OTHER | - | - | 471 | - | (6,497) | - | - | - | - | (2,129) | 1,762 | (184,014) |
| 39 | TOTAL | (8,492) | (12,421) | 471 | - | (6,497) | - | - | - | - | (2,129) | 1,762 | (187,981) |
| 40 | | | | | | | | | | | | | |
| 41 | DEPRECIATION & AMORTIZATION | - | - | - | - | - | - | - | - | - | - | - | (22,259) |
| 42 | AMORT OF PROP LOSSES & REG STU | - | - | - | - | - | - | - | - | - | - | - | - |
| 43 | TOTAL | - | - | - | - | - | - | - | - | - | - | - | (22,259) |
| 44 | | | | | | | | | | | | | |
| 45 | INCOME TAXES: | | | | | | | | | | | | |
| 46 | CURRENT: | | | | | | | | | | | | |
| 47 | FEDERAL | - | - | - | 12,830 | 39,493 | - | 2,092 | (177) | - | 693 | (574) | 62,085 |
| 48 | STATE | - | - | - | 2,731 | 8,406 | - | 445 | (38) | - | 148 | (122) | 13,213 |
| 49 | DEFERRED | 3,355 | 4,908 | (2,952) | - | (47,899) | 40,217 | - | - | - | - | - | 1,722 |
| 50 | TOTAL | 3,355 | 4,908 | (2,952) | 15,561 | - | 40,217 | 2,537 | (215) | - | 841 | (696) | 77,020 |
| 51 | | | | | | | | | | | | | |
| 52 | OTHER TAXES: | | | | | | | | | | | | |
| 53 | PROPERTY TAXES | - | - | - | - | - | - | - | - | - | - | - | 18,191 |
| 54 | SALES TAXES | - | - | - | - | - | - | - | - | - | - | - | - |
| 55 | FRANCHISE TAXES | - | - | - | - | - | - | - | - | - | - | - | - |
| 56 | TOTAL | - | - | - | - | - | - | - | - | - | - | - | 18,191 |
| 57 | | | | | | | | | | | | | |
| 58 | INTEREST EXPENSE - SYNCHRONIZED | - | - | - | - | - | - | - | - | - | - | - | (53,391) |
| 59 | | | | | | | | | | | | | |
| 60 | TOTAL | $ (5,137) | $ (7,513) | $ (2,481) | $ (23,824) | $ 108,669 | $ (61,573) | $ 6,446 | $ 38 | $ - | $ (1,288) | $ 1,086 | $ (199,274) |

ARIZONA PUBLIC SERVICE
INCOME STATEMENT PRO FORMA ADJUSTMENTS FOR CWC PURPOSES
TEST YEAR ENDED 12/31/2010
(THOUSANDS OF DOLLARS)

| | | 37 | 38 |
|---|---|---|---|
| | | CWC Factor | Total CWC Adjustment |
| LINE | DESCRIPTION | CWC Factor | Total Co. (000) |
| 1 | FUEL FOR ELECTRIC GENERATION: | | |
| 2 | COAL | 0.010820 | $ 527 |
| 3 | NATURAL GAS | 0.011200 | (884) |
| 4 | GAS MTM AND FUTURES | 0.000000 | - |
| 5 | HANDLING | 0.062510 | (9) |
| 6 | FUEL OIL | -0.002900 | - |
| 7 | NUCLEAR: | | - |
| 8 | AMORTIZATION | 0.000000 | - |
| 9 | SPENT FUEL | -0.106690 | 452 |
| 10 | TOTAL NUCLEAR FUEL | | 452 |
| 11 | | | |
| 12 | TOTAL FUEL | | 86 |
| 13 | | | |
| 14 | PURCHASED POWER | 0.008890 | (220) |
| 15 | POWER MTM | 0.000000 | - |
| 16 | POWER SUPPLY ADJUSTER | 0.000000 | - |
| 17 | TRANSMISSION BY OTHERS | -0.001700 | (9) |
| 18 | TOTAL PURCHASED POWER & TRANS | | (229) |
| 19 | | | |
| 20 | TOTAL FUEL AND PURCHASED POWEI | | (143) |
| 21 | | | |
| 22 | OTHER OPERATIONS & MAINTENANCE | | |
| 23 | PAYROLL | 0.082510 | 424 |
| 24 | INCENTIVE | -0.545410 | - |
| 25 | STOCK COMPENSATION | 0.000000 | - |
| 26 | SEVERANCE (EXCLUDES PENSION) | -0.110900 | 747 |
| 27 | PENSION AND OPEB | -0.000250 | (2) |
| 28 | EMPLOYEE BENEFITS | 0.067080 | - |
| 29 | PAYROLL TAXES | -0.005200 | - |
| 30 | MATERIALS & SUPPLIES | 0.035780 | - |
| 31 | VEHICLE LEASE PAYMENTS | 0.067040 | - |
| 32 | PREPAID VEHICLE LICENSES | 0.000000 | - |
| 33 | RENTS | 0.070450 | - |
| 34 | PREPAID RENTS | 0.000000 | - |
| 35 | PALO VERDE LEASE | -0.211330 | - |
| 36 | PALO VERDE S/L GAIN AMORT | 0.000000 | - |
| 37 | INSURANCE | 0.000000 | - |
| 38 | OTHER | 0.028120 | (5,174) |
| 39 | TOTAL | | (4,006) |
| 40 | | | |
| 41 | DEPRECIATION & AMORTIZATION | 0.000000 | - |
| 42 | AMORT OF PROP LOSSES & REG STUI | 0.000000 | - |
| 43 | TOTAL | | - |
| 44 | | | |
| 45 | INCOME TAXES: | | |
| 46 | CURRENT: | | |
| 47 | FEDERAL | -0.058970 | (3,661) |
| 48 | STATE | -0.074430 | (983) |
| 49 | DEFERRED | 0.000000 | - |
| 50 | TOTAL | | (4,645) |
| 51 | | | |
| 52 | OTHER TAXES: | | |
| 53 | PROPERTY TAXES | -0.475170 | (8,644) |
| 54 | SALES TAXES | -0.061510 | - |
| 55 | FRANCHISE TAXES | -0.101320 | - |
| 56 | TOTAL | | (8,644) |
| 57 | | | |
| 58 | INTEREST EXPENSE - SYNCHRONIZED | -0.159240 | 8,502 |
| 59 | | | |
| 60 | TOTAL | | $ (8,935) |
| | | Cost of Debt | 2.88% |
| | | Synchronized Interest | (257) |

# RUCO Pro-Forma Income Tax Calculation and Interest Expense Synchronization

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustment to Operating Income as Shown on Schedule C-2, page 5, column 13
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: INCOME TAXES

| Line No. | Description | | Amount | RUCO |
|---|---|---|---|---|
| 1. | Operating Income Before Income Tax | | $ - | $ - |
| 2. | Interest Expense and Other Net Deductions | | (60,142) | (57,259) |
| 3. | **Taxable Income** | | - | - |
| 4. | **Income Tax at 39.51%** | JCL_WP25 page 2 [A] | 23,762 | 22,623 |
| 5. | Deferred Tax | | - | - |
| 6. | **Operating Income After Tax** | | $ (23,762) | $ (22,623) |

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustment as Shown on Schedule C-2, page 5, column 13.
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: INCOME TAXES

| Line No. | Description | APS | RUCO | |
|---|---|---|---|---|
| 1. | Pre-Tax Operating Income (SFR Schedule C-1, line 11 + line 8) | $ 692,521 | $ 692,521 | |
| 2. | Allocated Interest Expense (unadjusted rate base * cost of debt) | (189,176) | (192,059) | RUCO adjusted rate base times RUCO Long term debt rate |
| 3. | Adjusted Operating Income | 503,345 | 500,462 | |
| 4. | Gross Income Tax at 39.51% | 198,872 | 197,732 | |
| 5. | Tax Effected Permanent Items | | | |
| 6. | Meals and Entertainment | 669 | 669 | |
| 7. | Non-Deductible Compensation | 58 | 58 | |
| 8. | Research & Development Credit | (2,667) | (2,667) | |
| 9. | Amortization of OPEB Subsidy PPACA | 1,004 | 1,004 | |
| 10. | Other Federal Tax Credits (Net) | (16) | (16) | |
| 11. | Amortization of FAS109 Liability | (13) | (13) | |
| 12. | Arizona Tax Credits | (641) | (641) | |
| 13. | Depreciation on AFUDC | 1,936 | 1,936 | |
| 14. | Net On-Going Tax Expense | 199,202 | 198,062 | |
| 15. | Actual Test Year Tax Expense (SFR Schedule C-1, line 8) | 175,440 | 175,440 | |
| 16. | Tax Pro Forma Adjustment | $ 23,762 [A] | $ 22,623 | |

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.15: Four Corners Reclamation costs. Refer to JCL_WP32 and Mr. La Benz' direct testimony at pages 28-29.

a. Provide the August 2010 Marston study.

b. Please confirm that APS' request for Four Corners Coal Reclamation costs is based on a four year amortization, wherein, as shown on JCL-WP32, page 27, APS proposes to amortize $25,122,294 over four years starting on July 1, 2012. If this is not accurate, explain fully.

c. Please provide the documents and orders upon which APS has relied for its assumption that the Four Corners Units 1-3 reclamation costs will be incurred from July 1, 2012 through June 30, 2016.

d. Please explain fully why the reclamation for Four Corners Units 1-3 cannot be done at the same time as the reclamation for Four Corners Units 4 and 5.

e. Please provide a calculation, similar to JCL_WP32, page 2 of 7, but which escalates the reclamation costs for Four Corners Units 1-3 through 6/30/2038 and bases the annual amortization amount on a 26 year amortization, similar to the reclamation cost amortization for Four Corners Units 4-5.

f. Are the mines and source of coal from BHP Billiton the same for Four Corners Units 1-3 and Four Corners Units 4-5? If not, please explain.

g. Please identify the coal source/mines, c ontract(s), a nd annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 1-3.

h. Please identify the coal source/mines, contract(s) and annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 4-5.

i. Please identify and explain how the coal source/mines, contract(s), and annual purchase tonnage commitments for each current coal supply contract currently serving Four Corners Units 1-3 and Units 4-5 would be affected by the retirement of Units 1-3 and extended operating life of Units 4-5.

j. Would any of the coal supply currently serving Four Corners Units 1-3 be used or usable to supply Four Corners Units 4-5 if the useful life of Units 4-5 is extended through 2038? If not, explain fully why not. If so, please explain how that would occur.

Witness: Jay La Benz

# Four Corners Coal Reclamation
## Pro Forma - Regulatory Liability

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | Units 1-3 | | Units 4-5 | | Total | |
| 1 | Marston Study Final Reclamation Direct Costs [1] | | $ | 52,151,708 | $ | 18,516,490 | $ | 70,668,198 | |
| 2 | Marston Study Final Reclamation Indirect Costs[1] | | | 6,996,544 | | 2,484,127 | | 9,480,671 | |
| 3 | Taxes & Royalties ((Line 1 + Line 2) * 19.753%) | B1[3/] | | 11,683,259 | | 4,148,147 | | 15,831,406 | |
| 4 | Total Final Reclamation as of 12/31/2010 | | | 70,831,511 | | 25,148,764 | | 95,980,275 | |
| 5 | Escalated Total Final Reclamation[2] | A1[4/] | | 73,959,382 | | 49,593,293 | | 123,552,675 | |
| 6 | Actual amount accrued through mid 2012 | B1[4/] | | 48,837,088 | | 17,339,633 | | 66,176,721 | |
| 7 | Amount to be recovered as of 7/1/2012 | | | 25,122,294 | | 32,253,660 | | 57,375,954 | |
| 8 | Rate Recovery 4-26 years (7/1/2012-6/30/2038 (Line 6 / 4 and 26))[3]<br>(Recovery period reflects term of the BHP coal contract) | | | 6,280,573 | | 1,240,525 | | 7,521,099 | |
| 9 | Less Test Year Expense | A1[5/] | | 963,011 | | 341,917 | | 1,304,928 | |
| 10 | Pro Forma Adjustment | | $ | 5,317,563 | $ | 898,608 | $ | 6,216,171 | A1 |

[1] APS' share of Four Corners Units 1-3 is approximately 30% and 10% for Units 4-5 of the total August 2010 Marston study.

[2] Escalation calculated at 2.5% as of 1/1/2011 through 9/30/2012 for U 1-3 and through 6/30/2038 for U 4-5

[3] Four Corners Units 1-3 have a 4 year recovery period and account for approximately 74% of the costs.
Four Corners Units 4-5 have a 26 year recovery period and account for approximately 26% of the costs.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.15: Four Corners Reclamation costs. Refer to JCL_WP32 and Mr. La Benz' direct testimony at pages 28-29.

a. Provide the August 2010 Marston study.

b. Please confirm that APS' request for Four Corners Coal Reclamation costs is based on a four year amortization, wherein, as shown on JCL-WP32, page 27, APS proposes to amortize $25,122,294 over four years starting on July 1, 2012. If this is not accurate, explain fully.

c. Please provide the documents and orders upon which APS has relied for its assumption that the Four Corners Units 1-3 reclamation costs will be incurred from July 1, 2012 through June 30, 2016.

d. Please explain fully why the reclamation for Four Corners Units 1-3 cannot be done at the same time as the reclamation for Four Corners Units 4 and 5.

e. Please provide a calculation, similar to JCL_WP32, page 2 of 7, but which escalates the reclamation costs for Four Corners Units 1-3 through 6/30/2038 and bases the annual amortization amount on a 26 year amortization, similar to the reclamation cost amortization for Four Corners Units 4-5.

f. Are the mines and source of coal from BHP Billiton the same for Four Corners Units 1-3 and Four Corners Units 4-5? If not, please explain.

g. Please identify the coal source/mines, contract(s), and annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 1-3.

h. Please identify the coal source/mines, contract(s) and annual purchase tonnage commitments for each such contract in place during 2010 to serve Four Corners Units 4-5.

i. Please identify and explain how the coal source/mines, contract(s), and annual purchase tonnage commitments for each current coal supply contract currently serving Four Corners Units 1-3 and Units 4-5 would be affected by the retirement of Units 1-3 and extended operating life of Units 4-5.

j. Would any of the coal supply currently serving Four Corners Units 1-3 be used or usable to supply Four Corners Units 4-5 if the useful life of Units 4-5 is extended through 2038? If not, explain fully why not. If so, please explain how that would occur.

Witness: Jay La Benz

Staff 25.15:

k. Will the coal supply contract for Four Corners Units 4-5 be extended or renegotiated if those units operate through 2038.

l. Refer to JCL_WP32, page 2 of 7. Please provide notes 4 and 5, which are referenced on lines 5 and 6, and on line 9, respectively.

m. Why has APS used a 2.5% escalation rate on JCL_WP32, page 2 of 7 for Four Corners coal reclamation costs, but a 2.0% escalation rate on Exhibit REW-2, Statement G, page 70 for dismantlement costs?

n. Provide all support APS relied upon for the 2.5% escalation rate on JCL_WP32, page 2 of 7.

o. For each contract for coal supply serving Four Corners, please identify the coal contract provisions that relate to reclamation costs.

p. Please provide the excerpts of the coal contracts for the provisions that relate to reclamation costs, identified in part o.

q. Will the coal reclamation work be done by APS employees or contractors? Explain.

r. Has APS issued any RFPs or solicitations related to Four Corners Units 1-3 coal reclamation work? If not, explain fully why not. If so, please identify and describe the RFPs and solicitations, indicate when they were issued, and explain whether APS has received any responses.

Response:

a. Please refer to APS's response to Pre-filed 1.29 APS14149.

b. Yes, for the Four Corners Units 1-3 portion of Coal Reclamation costs, APS proposes to amortize $25,122,294 over four years starting on July 1, 2012.

c. Assuming that Four Corners Units 1-3 will cease operations at the end of the current coal contract, that will occur by July 6, 2016, APS is under a contract with BHP, which requires APS to fund to BHP the final reclamation costs related to the closing units prior to final closure of those units. Please see the relevant portion of the BHP contract attached as APS14980. Please note the attachment is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jay La Benz

Response to Staff 25.15 Continued:

d. The final physical reclamation of the mine will begin when coal is no longer provided out of the mine for any Four Corners Unit. However, under the assumption that Four Corners Units 1-3 cease operation in 2016, APS ,under the contract with BHP, is required to fund an escrow account for the final reclamation costs related to the closing units prior to those units ceasing operation. The costs for the closing units would be apportioned based upon the historical production volumes for Units 1-3 (APS owned) and Units 4/5 (Participant owned). Please see response to (i) and (p) for related contract details.

e. See attached schedules, as APS14981, reflecting pro forma escalating the reclamation costs for Four Corners Unit 1-3 through 6/30/2038.

f. Yes, the mines and source of coal from BHP Billiton are the same for Four Corners Units 1-3 and Four Corners Units 4-5.

g. The BHP Navajo Coal Company is the sole source provider of coal to the Four Corners Power Plant Units 1-5, with supply sourced from the BHP Navajo Mine. The coal is provided under the terms of the "Four Corners Coal Supply Agreement".

   Responsibility for the minimum Base Annual Requirement among the Units 1-5 is allocated as follows:

   - Plant Units 1, 2, and 3 shall be responsible for 34 x 10^12 Btu/year of the Base Annual Requirement (approx. 1.91M tons)

   - Plant Units 4 and 5 shall be responsible for 80 x 10^12 Btu/year of the Base Annual Requirement (approx. 4.49M tons)

h. Please see response (g).

i. The current "Four Corner Coal Supply Agreement" expires July 6, 2016. An extended operating life for Units 4-5 will require the negotiation of a new or extended coal supply agreement for future years.

   If Units 1-3 are retired prior to 2016, there will be two provisions of the current agreement that will require

Response to Staff 25.15 Continued:

attention. These are:

Shortfall in the purchase of the base annual tonnage requirement. The current minimum purchase requirement is approx. 6.4 M tons/year. APS Units 1-3 have a minimum purchase requirement of 1.91M tons/year. To the extent that the annual purchase obligation to BHP falls short of 6.4 M tons/yr., an accounting for the shortfall will be required. Over the past 10 years, Units 4/5 have burned approximately 5.9M tons/yr.

Final Reclamation Liability. An estimate and agreement of the amount of final reclamation liability for the BHP Navajo Mine will need to be made at the time of the early retirement of Units 1-3. The allocation of Units 1-3 share of this liability will be calculated and will be funded into an escrow account that is currently established for this purpose. The escrow account will remain under the control of APS until the BHP Navajo Mine ceases production and the final reclamation payment for Units 1-5 is made to BHP. This final reclamation payment will be based upon an estimate of final reclamation liability at the time of mine closure (which will be different than the liability estimated at the time of retirement of Units 1-3).

j. The coal supply reserve serving Four Corners Units 1-3 and Unit 4-5 is the same.

k. An extended operating life for Units 4-5 will require the negotiation of a new or extended coal supply agreement for those units to operate through 2038.

l. References A1[4/], B1[4/] and A1[5/] do not refer to notes but rather "tick marks" to numbers on pages 6 of 7, 4 of 7 and 7 of 7 respectively.

m. The 2.5% escalation rate on JCL_WP32, page 2 of 7 for Four Corners coal reclamation costs in based on the average CPI for year 2000 through 2010. The 2.0% escalation rate for dismantlement costs is based on the rate utilized in APS Asset Retirement Obligation calculation model for removal/decommissioning of long lived assets. The activities performed for mine reclamation versus plant dismantlement would be different; thus the escalation rates would not necessarily be the same.

Witness: Jay La Benz

Response to Staff 25.15 Continued:

n. Please see attached APS14982 for support of the 2.5% escalation rate.

o. Sections 4.1(a), 4.1(c)(ii) and Section 4.5 in the coal supply contract with BHP Navajo Coal Company relate to provisions for final reclamation costs.

p. Please see APS14980, attached, for excerpts of the coal contract for provisions relating to reclamation costs. Please note the attachment is confidential and is being provided pursuant to an executed protective agreement.

q. No, the performance of the reclamation activities are the responsibility of BHP.

r. No, the performance of the reclamation activities are the responsibility of BHP.

# Operating Income Proforma Adjustment
## FC Coal Reclamation
## (Dollars in Thousands)
## STF 25.15 e

| Line No. | Description | | Annualize Four Corners Coal Reclamation |
|---|---|---|---|
| 1 | Electric Operating Revenues | | - |
| 2 | Fuel Expense | A1[2/] | 3,430 |
| 3 | Oper Rev Less Fuel | | (3,430) |
| | Other Operating Expenses: | | |
| 4 | Operations Excluding Fuel Expenses | | - |
| 5 | Maintenance | | - |
| 6 | Subtotal | | - |
| 7 | Depreciation | | - |
| 8 | Amortization of Gain | | - |
| 9 | Administrative and General | | - |
| 10 | Other Taxes | | - |
| 11 | Total | | - |
| 12 | Operating Income | | (3,430) |
| 13 | Net Deductions | | - |
| 14 | Interest | | - |
| 15 | Taxable Income | | (3,430) |
| 16 | Current Income Tax Rate - 39.51% | | (1,355) |
| 17 | Deferred Tax | | - |
| 18 | Net Income | | (2,075) |

Purpose: Adjustment to annual coal reclamation amortization due to increase in final reclamation costs based on study completed by Marston in August 2010. Also, adjustment to amortization period f of reclamation from 2016 to 2038 for assumed extension of coal agreement.

## Four Corners Coal Reclamation
## Pro Forma - Regulatory Liability
## For STF25.15 e

| | | | Units 1-3 | Units 4-5 | Total | |
|---|---|---|---|---|---|---|
| 1 | Marston Study Final Reclamation Direct Costs [1] | | $ 52,151,708 | $ 18,516,490 | $ 70,668,198 | |
| 2 | Marston Study Final Reclamation Indirect Costs[1] | | 6,996,544 | 2,484,127 | 9,480,671 | |
| 3 | Taxes & Royalties ((Line 1 + Line 2) * 19.753%) | B1[3/] | 11,683,259 | 4,148,147 | 15,831,406 | |
| 4 | Total Final Reclamation as of 12/31/2010 | | 70,831,511 | 25,148,764 | 95,980,275 | |
| 5 | Escalated Total Final Reclamation[2] | A1[4/] | 139,679,543 | 49,593,293 | 189,272,836 | |
| 6 | Actual amount accrued through mid 2012 | B1[4/] | 48,837,088 | 17,339,633 | 66,176,721 | |
| 7 | Amount to be recovered as of 7/1/2012 | | 90,842,455 | 32,253,660 | 123,096,115 | |
| 8 | Rate Recovery 26 years (7/1/2012-6/30/2038 (Line 6 / 26))[3]<br>(Recovery period reflects term of the BHP coal contract) | | 3,493,941 | 1,240,525 | 4,734,466 | |
| 9 | Less Test Year Expense | A1[5/] | 963,011 | 341,917 | 1,304,928 | |
| 10 | Pro Forma Adjustment | | $ 2,530,930 | $ 898,608 | $ 3,429,538 | A1 |

[1] APS' share of Four Corners Units 1-3 is approximately 30% and 10% for Units 4-5 of the total August 2010 Marston study.
[2] Escalation calculated at 2.5% as of 1/1/2011 through 6/30/2038 for U 1-5
[3] Four Corners Units 1-3 have a 26 year recovery period and account for approximately 74% of the costs.
Four Corners Units 4-5 have a 26 year recovery period and account for approximately 26% of the costs.

# Four Corners
# Coal Reclamation
# Taxes, Royalties and Indirects (Rates applied to Coal)
# STF 25.15 e

| | | |
|---|---|---|
| Royalty | 12.500% | |
| Business Activity Tax | 5.000% | |
| New Mexico Gross Receipts Tax | 6.313% | |
| BAT Credit | -1.250% | |
| GRT Credit | -3.750% | |
| Conservation & Resource ExciseTax | 0.940% | |
| Total | 19.753% | **B1** |

**Four Corners Coal Reclamation**
**Projected Balances in Regulatory Asset and Coal Reclamation Liability**
**STF 25.15 e**

| Income Statement | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|
| 1 2002/Decision 67744 (4/1/2005) | 636,635.00 | 636,636.86 | 636,845.30 | 636,845.05 | 636,773.15 | 318,422.52 | | |
| 2 TY 9/30/2005 Decision # 69663 (7/1/2007) | | | | | | 652,463.52 | 1,304,927.04 | 978,695.28 |
| 3 TY 12/31/2007 (10/1/2009) | | | | | | | | 326,231.76 |
| 4 TY 12/31/2010 (7/1/2012) | | | | | | | | |
| 5 Total | 636,635.00 | 636,636.86 | 636,845.30 | 636,845.05 | 636,773.15 | 970,886.04 | 1,304,927.04 | 1,304,927.04 |
| **Balance Sheet** | | | | | | | | |
| **Account 1823 - Regulatory Asset** | | | | | | | | |
| 6 Beginning Balance | - | - | - | - | 13,033,650.00 | 12,396,804.96 | 11,425,918.92 | 10,120,991.88 |
| 7 Debit | - | - | - | 13,033,650.00 | | | | |
| 8 Credit | - | - | - | - | (636,845.04) | (970,886.04) | (1,304,927.04) | (1,304,927.04) |
| 9 Ending Balance | - | - | - | 13,033,650.00 | 12,396,804.96 | 11,425,918.92 | 10,120,991.88 | 8,816,064.84 |
| **Account 2530 - Liability** | | | | | | | | |
| 10 Beginning Balance | (56,149,855.60) | (56,786,490.60) | (57,423,127.46) | (58,059,972.76) | (71,730,467.81) | (71,730,467.81) | (71,730,467.81) | (71,730,467.81) |
| 11 Debit | - | - | - | - | | | | |
| 12 Credit | (636,635.00) | (636,636.86) | (636,845.30) | (13,670,495.05) | | | | |
| 13 Ending Balance | (56,786,490.60) | (57,423,127.46) | (58,059,972.76) | (71,730,467.81) | (71,730,467.81) | (71,730,467.81) | (71,730,467.81) | (71,730,467.81) |
| **Net Balance Sheet** | (56,786,490.60) | (57,423,127.46) | (58,059,972.76) | (58,696,817.81) | (59,333,662.85) | (60,304,548.89) | (61,609,475.93) | (62,914,402.97) |

| Income Statement | 2010 | 2011 | 2012 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| 13 2002/Decision 67744 (4/1/2005) | | | | | | | | |
| 14 TY 9/30/2005 (7/1/2007) | | | | | | | | |
| 15 TY 12/31/2006 (10/1/2009) | 1,304,927.04 | 1,304,927.04 | 652,463.52 | | | | | |
| 15 TY 12/31/2010 (7/1/2012) | - | - | | 2,367,233.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 |
| 16 Total | 1,304,927.04 | 1,304,927.04 | 652,463.52 | 2,367,233.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 |
| **Balance Sheet** | | | | | | | | |
| **Account 1823 - Regulatory Asset (Including Escalation)** | | | | | | | | |
| 17 Beginning Balance | 8,816,064.84 | 31,760,945.80 | 32,855,525.76 | 32,203,062.24 | 32,295,324.24 | 30,081,840.24 | 27,931,380.24 | 25,845,521.24 |
| 18 Debit | 24,249,808.00 | 2,399,507.00 | - | 2,459,495.00 | 2,520,982.00 | 2,584,006.00 | 2,648,607.00 | 2,714,822.00 |
| 19 Credit | (1,304,927.04) | (1,304,927.04) | (652,463.52) | (2,367,233.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) |
| 20 Ending Balance | 31,760,945.80 | 32,855,525.76 | 32,203,062.24 | 32,295,324.24 | 30,081,840.24 | 27,931,380.24 | 25,845,521.24 | 23,825,877.24 |
| **Account 2530/2540 - Liability/Regulatory Liability** | | | | | | | | |
| 21 Beginning Balance | (71,730,467.81) | (95,980,275.81) | (98,379,782.81) | (98,379,782.81) | (100,839,277.81) | (103,360,259.81) | (105,944,265.81) | (108,592,872.81) |
| 22 Debit | - | - | - | - | - | - | - | - |
| 23 Credit | (24,249,808.00) | (2,399,507.00) | - | (2,459,495.00) | (2,520,982.00) | (2,584,006.00) | (2,648,607.00) | (2,714,822.00) |
| 24 Ending Balance | (95,980,275.81) | (98,379,782.81) | (98,379,782.81) | (100,839,277.81) | (103,360,259.81) | (105,944,265.81) | (108,592,872.81) | (111,307,694.81) |
| **Net Balance Sheet** | (64,219,330.01) | (65,524,257.05) | (66,176,720.57) | (68,543,953.57) | (73,278,419.57) | (78,012,885.57) | (82,747,351.57) | (87,481,817.57) |

**Four Corners Coal Reclamation**
**Projected Balances in Regulatory Asset and Coal Reclamation Liability**
**STF 25.15 e**

| Income Statement | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|
| 13 2002/Decision 67744 (4/1/2005) | | | | | | | | |
| 14 TY 9/30/2005 (7/1/2007) | | | | | | | | |
| 15 TY 12/31/2006 (10/1/2009) | | | | | | | | |
| 15 TY 12/31/2010 (7/1/2012) | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 |
| 16 Total | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 |
| **Balance Sheet** | | | | | | | | |
| **Account 1823 - Regulatory Asset (Including Escalation)** | | | | | | | | |
| 17 Beginning Balance | 23,825,877.24 | 21,874,103.24 | 19,991,897.24 | 18,180,997.24 | 16,443,186.24 | 14,780,292.24 | 13,194,187.24 | 11,686,791.24 |
| 18 Debit | 2,782,692.00 | 2,852,260.00 | 2,923,566.00 | 2,996,655.00 | 3,071,572.00 | 3,148,361.00 | 3,227,070.00 | 3,307,747.00 |
| 19 Credit | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) |
| 20 Ending Balance | 21,874,103.24 | 19,991,897.24 | 18,180,997.24 | 16,443,186.24 | 14,780,292.24 | 13,194,187.24 | 11,686,791.24 | 10,260,072.24 |
| **Account 2530/2540 - Liability/Regulatory Liability** | | | | | | | | |
| 21 Beginning Balance | (111,307,694.81) | (114,090,386.81) | (116,942,646.81) | (119,866,212.81) | (122,862,867.81) | (125,934,439.81) | (129,082,800.81) | (132,309,870.81) |
| 22 Debit | - | - | - | - | - | - | - | - |
| 23 Credit | (2,782,692.00) | (2,852,260.00) | (2,923,566.00) | (2,996,655.00) | (3,071,572.00) | (3,148,361.00) | (3,227,070.00) | (3,307,747.00) |
| 24 Ending Balance | (114,090,386.81) | (116,942,646.81) | (119,866,212.81) | (122,862,867.81) | (125,934,439.81) | (129,082,800.81) | (132,309,870.81) | (135,617,617.81) |
| **Net Balance Sheet** | (92,216,283.57) | (96,950,749.57) | (101,685,215.57) | (106,419,681.57) | (111,154,147.57) | (115,888,613.57) | (120,623,079.57) | (125,357,545.57) |

| Income Statement | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|
| 13 2002/Decision 67744 (4/1/2005) | | | | | | | | |
| 14 TY 9/30/2005 (7/1/2007) | | | | | | | | |
| 15 TY 12/31/2006 (10/1/2009) | | | | | | | | |
| 15 TY 12/31/2010 (7/1/2012) | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 |
| 16 Total | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 |
| **Balance Sheet** | | | | | | | | |
| **Account 1823 - Regulatory Asset (Including Escalation)** | | | | | | | | |
| 17 Beginning Balance | 10,260,072.24 | 8,916,046.24 | 7,656,781.24 | 6,484,396.24 | 5,401,064.24 | 4,409,010.24 | 3,510,516.24 | 2,707,921.24 |
| 18 Debit | 3,390,440.00 | 3,475,201.00 | 3,562,081.00 | 3,651,134.00 | 3,742,412.00 | 3,835,972.00 | 3,931,871.00 | 4,030,168.00 |
| 19 Credit | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) |
| 20 Ending Balance | 8,916,046.24 | 7,656,781.24 | 6,484,396.24 | 5,401,064.24 | 4,409,010.24 | 3,510,516.24 | 2,707,921.24 | 2,003,623.24 |
| **Account 2530/2540 - Liability/Regulatory Liability** | | | | | | | | |
| 21 Beginning Balance | (135,617,617.81) | (139,008,057.81) | (142,483,258.81) | (146,045,339.81) | (149,696,473.81) | (153,438,885.81) | (157,274,857.81) | (161,206,728.81) |
| 22 Debit | - | - | - | - | - | - | - | - |
| 23 Credit | (3,390,440.00) | (3,475,201.00) | (3,562,081.00) | (3,651,134.00) | (3,742,412.00) | (3,835,972.00) | (3,931,871.00) | (4,030,168.00) |
| 24 Ending Balance | (139,008,057.81) | (142,483,258.81) | (146,045,339.81) | (149,696,473.81) | (153,438,885.81) | (157,274,857.81) | (161,206,728.81) | (165,236,896.81) |

**Four Corners Coal Reclamation**
**Projected Balances in Regulatory Asset and Coal Reclamation Liability**
**STF 25.15 e**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Net Balance Sheet** | (130,092,011.57) | (134,826,477.57) | (139,560,943.57) | (144,295,409.57) | (149,029,875.57) | (153,764,341.57) | (158,498,807.57) | (163,233,273.57) |

**Four Corners Coal Reclamation**
**Projected Balances in Regulatory Asset and Coal Reclamation Liability**
**STF 25.15 e**

| | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|
| **Income Statement** | | | | | | |
| 13 2002/Decision 67744 (4/1/2005) | | | | | | |
| 14 TY 9/30/2005 (7/1/2007) | | | | | | |
| 15 TY 12/31/2006 (10/1/2009) | | | | | | |
| 15 TY 12/31/2010 (7/1/2012) | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 2,367,232.24 |
| 16 Total | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 4,734,466.00 | 2,367,232.24 |
| **Balance Sheet** | | | | | | |
| **Account 1823 - Regulatory Asset (Including Escalation)** | | | | | | |
| 17 Beginning Balance | 2,003,623.24 | 1,400,079.24 | 899,809.24 | 505,393.24 | 219,479.24 | 44,778.24 |
| 18 Debit | 4,130,922.00 | 4,234,196.00 | 4,340,050.00 | 4,448,552.00 | 4,559,765.00 | 2,322,454.00 |
| 19 Credit | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (4,734,466.00) | (2,367,232.24) |
| 20 Ending Balance | 1,400,079.24 | 899,809.24 | 505,393.24 | 219,479.24 | 44,778.24 | 0.00 |
| **Account 2530/2540 - Liability/Regulatory Liability** | | | | | | |
| 21 Beginning Balance | (165,236,896.81) | (169,367,818.81) | (173,602,014.81) | (177,942,064.81) | (182,390,616.81) | (186,950,381.81) |
| 22 Debit | - | - | - | - | - | - |
| 23 Credit | (4,130,922.00) | (4,234,196.00) | (4,340,050.00) | (4,448,552.00) | (4,559,765.00) | (2,322,454.00) |
| 24 Ending Balance | (169,367,818.81) | (173,602,014.81) | (177,942,064.81) | (182,390,616.81) | (186,950,381.81) | (189,272,835.81) |
| | | | | | | **A1** |
| **Net Balance Sheet** | (167,967,739.57) | (172,702,205.57) | (177,436,671.57) | (182,171,137.57) | (186,905,603.57) | (189,272,835.81) |

**Four Corners Coal Reclamation**
**Historical Cost Summary**
**1/1/07 - 12/31/10**
**STF 25.15 e**

**Four Corner Coal Reclamation Expense**
**Charge # 99-501-013**

| | **2007** | **2008** | **2009** | **2010** |
|---|---|---|---|---|
| January | 53,070.42 | 108,744.00 | 108,744.00 | 108,744.00 |
| February | 53,070.42 | 108,744.00 | 108,744.00 | 108,744.00 |
| March | 53,070.42 | 108,744.00 | 108,744.00 | 108,744.00 |
| April | 53,070.42 | 108,744.00 | 108,744.00 | 108,744.00 |
| May | 53,070.42 | 108,744.00 | 108,744.00 | 108,744.00 |
| June | 53,070.42 | 108,744.00 | 108,744.00 | 108,744.00 |
| July | 108,744.00 | 108,744.00 | 108,744.00 | 108,744.00 |
| August | 108,744.00 | 108,744.00 | 108,744.00 | 108,744.00 |
| September | 108,744.00 | 108,744.00 | 108,744.00 | 108,744.00 |
| October | 108,744.00 | 108,744.00 | 108,744.00 | 108,744.00 |
| November | 108,744.00 | 108,744.00 | 108,744.00 | 108,744.00 |
| December | 108,744.00 | 108,744.00 | 108,744.00 | 108,744.00 |
| Total | 970,886.52 | 1,304,928.00 | 1,304,928.00 | 1,304,928.00 |
| | | | | **A1** |

## Consumer Price Index - All Urban Consumers
## 12-Month Percent Change

**Series Id:** CUUR0000SA0
**Not Seasonally Adjusted**
**Area:** U.S. city average
**Item:** All items
**Base Period:** 1982-84=100
**Years:** 2000 to 2010

| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2000 | 2.7 | 3.2 | 3.8 | 3.1 | 3.2 | 3.7 | 3.7 | 3.4 | 3.5 | 3.4 | 3.4 | 3.4 | 3.4 |
| 2001 | 3.7 | 3.5 | 2.9 | 3.3 | 3.6 | 3.2 | 2.7 | 2.7 | 2.6 | 2.1 | 1.9 | 1.6 | 2.8 |
| 2002 | 1.1 | 1.1 | 1.5 | 1.6 | 1.2 | 1.1 | 1.5 | 1.8 | 1.5 | 2.0 | 2.2 | 2.4 | 1.6 |
| 2003 | 2.6 | 3.0 | 3.0 | 2.2 | 2.1 | 2.1 | 2.1 | 2.2 | 2.3 | 2.0 | 1.8 | 1.9 | 2.3 |
| 2004 | 1.9 | 1.7 | 1.7 | 2.3 | 3.1 | 3.3 | 3.0 | 2.7 | 2.5 | 3.2 | 3.5 | 3.3 | 2.7 |
| 2005 | 3.0 | 3.0 | 3.1 | 3.5 | 2.8 | 2.5 | 3.2 | 3.6 | 4.7 | 4.3 | 3.5 | 3.4 | 3.4 |
| 2006 | 4.0 | 3.6 | 3.4 | 3.5 | 4.2 | 4.3 | 4.1 | 3.8 | 2.1 | 1.3 | 2.0 | 2.5 | 3.2 |
| 2007 | 2.1 | 2.4 | 2.8 | 2.6 | 2.7 | 2.7 | 2.4 | 2.0 | 2.8 | 3.5 | 4.3 | 4.1 | 2.8 |
| 2008 | 4.3 | 4.0 | 4.0 | 3.9 | 4.2 | 5.0 | 5.6 | 5.4 | 4.9 | 3.7 | 1.1 | 0.1 | 3.8 |
| 2009 | 0.0 | 0.2 | -0.4 | -0.7 | -1.3 | -1.4 | -2.1 | -1.5 | -1.3 | -0.2 | 1.8 | 2.7 | -0.4 |
| 2010 | 2.6 | 2.1 | 2.3 | 2.2 | 2.0 | 1.1 | 1.2 | 1.1 | 1.1 | 1.2 | 1.1 | 1.5 | 1.6 |
| | | | | | | | | | | 11 Year Average CPI: | | | 2.5 |

Source: Bureau of Labor Statistics Data
http://data.bls.gov/pdq/SurveyOutputServlet

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

BEFORE THE

ARIZONA CORPORATION COMMISSION

ADDITONAL DIRECT TESTIMONY OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

November 23, 2011

**TABLE OF CONTENTS**

**INTRODUCTION**

**Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Frank Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding utility industries 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 FANK RADIGAN WHO PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?**

A. Yes.

**Q. WHAT IS THE PURPOSE OF YOUR ADDITONAL DIRECT TESTIMONY?**

A. I will discuss Arizona Public Service Company's ("APS" or the "Company") proposed decoupling mechanism – the "Efficiency and Infrastructure Account Mechanism" (EIA) sponsored by Company Witness Leland Snook. The decoupling mechanism is a full revenue per customer decoupling mechanism which the Company states is the most common decoupling mechanism used around the country (Snook direct at page 4).

## EXECUTIVE SUMMARY

**Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.**

A. RUCO believes it is inappropriate to implement a decoupling mechanism during this period of economic uncertainty and financial stress for ratepayers. Experience from across the country has shown that implementation of decoupling during times of economic stress have actually resulted in their subsequent cancellation which therefore results in decoupling as a detriment to energy conservation rather than an assistance. Second, RUCO finds that with all of the adjustor mechanisms being requested in this case, full revenue decoupling is unnecessary. For example, with the Company's proposed EIA and Environmental and Reliability Account ("ERA"), the Company would be allowed to retain all money from customer growth and carrying charges on all generation plant associated with that growth. Third, while RUCO can easily recognize decoupling as a utility benefit, RUCO cannot justify the corresponding and equal ratepayer burden on all customers when a review of customer usage data shows that it is only a few large users that impose an undue burden on the electric system. RUCO believes that the Commission should first strive to establish a rate design which encourages conservation and avoid implementation of a customer-wide full revenue decoupling mechanism.

**Q. WHAT DOES RUCO RECOMMEND?**

A. RUCO recognizes that the Commission has mandated that APS implement programs to reduce the amount of energy it sells. Since rates are set on a historical test year using historical test year consumption data, RUCO recognizes that reduced sales without adding new customers could play a factor in the erosion of a utility's ROR[1]. For that reason, ***RUCO believes it is appropriate to provide an alternate proposal to assist the utility in maintaining financial health without shifting risk to the ratepayers***. It is with this in mind that RUCO offers its two alternatives to the EIA.

In lieu of a decoupling mechanism, RUCO offers two different alternatives that provide the utility with financial safeguards yet does not shift the utility's business risk on to the ratepayer. First, in his direct testimony Mr. Snook acknowledges that there is a rate design solution that would protect the Company's financial health while at the same time encouraging conservation (Snook direct at page 8). This rate design approach known as Straight Fixed-Variable ("SFV") would resolve the financial disincentive by having all fixed costs of service would be collected through fixed charges and only variable costs of service would be collected through usage charges (Id). This approach would

[1] But RUCO does not agree that a reduction in use per customer consumption is the sole factor – or even the major factor – in the utility's eroded ROR.

require very high basic service charges and he calculates that the basic service charges for residential service would need to be raised to over $90 per month (Id). Mr. Snook then dismisses this option as being burdensome to customers and therefore unworkable (Id).

What Mr. Snook fails to realize is that that a large majority of customers are small users and it is only a few customers that use most of the power. What this means to energy conservation is that the vast majority of customers whose usage is relatively constant is that their ability to conserve is also small and losses through energy conservation is minimal. On the other hand the few large customers can be encouraged to conserve through aggressive rate design – just over 5% of the residential customers use approximately 15% of the energy sold to the whole residential class. Knowledge of these two facts therefore allows the regulator to address the financial disincentive by designing rates that recover most of the fixed cost through a combination of higher basic service charges and slightly higher charges for the first block of power used. A rate design where energy conservation is encouraged can be achieved through aggressive high volumetric charges for large energy use.

The first option, the rate design option, is similar to the proposal RUCO made in the Southwest Gas and recent UNS rate cases where RUCO proposes to move more of the revenue requirement into the fixed monthly rate to provide enhanced revenue stability to the utility. RUCO's proposal, however, is not a Straight Fixed-Variable rate proposal would not nearly result in the $90 plus fixed service charge that Mr. Snook's talks of.

The second option is to provide the utility with a cost of equity ***premium*** in lieu of decoupling. Arizona, along with many other jurisdictions, has debated whether to reduce the authorized cost of equity if decoupling is approved in recognition of reduced business risk. RUCO argues that an increase in the cost of equity as an alternative to decoupling would follow a similar logic. As an alternative to the EIA, RUCO recommends adding a premium of five (5) basis points to RUCO's recommended ROE of 10.00%, increasing the recommended ROE to 10.05%.

## PROPOSED EFFICIENCY INFRASTRUCTURE ACCOUNT MECHANISM

**Q. PLEASE DISCUSS THE PROPOSD EFFICIENCY INFRASTRUCTURE ACCOUNT MECHANISM ("EIA").**

A. The Efficiency and Infrastructure Account Mechanism is sponsored by Company witness Leland Snook. The decoupling mechanism is a full revenue per customer decoupling mechanism which the Company states is the most common decoupling mechanism used around the country (Snook direct at page 4).

Mr. Snook states that his proposal addresses the need to modernize the Company's rate structure by adopting a mechanism that will, among other things, allow APS to continue to actively promote energy efficiency and distributed energy programs (Snook direct at page 1). This new rate structure Mr. Snook argues will align the Company's and customers' financial interests, resulting in a more reasonable opportunity for the Company to collect its fixed costs of providing service (Id).

Currently, the vast majority of APS's revenues are collected through volumetric kWh energy charges (Snook direct at page 7). Therefore, the more energy a customer conserves or self-produces, the less fixed-cost recovery APS will receive (Id). In essence, with the implementation of EE and DG, the historic volumetric pricing structure deprives APS from having a reasonable opportunity to earn its return authorized by the Commission (Id).

Mr. Snook states that a rate design approach known as Straight Fixed-Variable ("SFV") would resolve the financial disincentive (Snook direct at page 8). In this rate design method, all fixed costs of service would be collected through fixed charges and only variable costs of service would be collected through usage charges (Id). This approach would require very high basic service charges which would be particularly burdensome for many residential and smaller commercial customers (Id).

In lieu of the SFV approach APS is proposing its EIA, which is a revenue per customer decoupling mechanism consistent with the Commission approved Policy Statement[2] (Snook direct at page 4). Mr. Snook states that this method was the model preferred by the majority[3] of stakeholders who participated in the Commission Decoupling Workshops and is the mechanism most commonly applied in other regulatory jurisdictions (Id).

Mr. Snook argues that a revenue per customer decoupling mechanism is the most appropriate mechanism for the following reasons:

- It modernizes the rate structure and aligns the Company's and customers' interests by updating customer billing determinants annually in a simple and straightforward manner;
- It is the most commonly applied form of decoupling within the electric and gas utility industries;

---

[2] Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-000005-08-0314 and G-00000C-08-0314, issued December 29, 2010 (the "Policy Statement").

[3] RUCO did not "prefer" this model to address the disincentive issue.

- It properly removes the link between volumetric sales and revenue collection, thus eliminating the disincentive associated with implementing EE programs and instead allows a utility to willingly engage in and promote EE programs; and
- It allows a utility to collect a greater portion of its authorized fixed cost of service (as determined within a rate case) associated with both existing and future customers regardless of sales levels. (Snook at page 14)

Mr. Snook also states that the Commission's Policy Statement suggests that a revenue per customer decoupling mechanism is suggested as being better suited than other alternative mechanisms to respond to customer growth typically experienced in Arizona. APS agrees with this observation. (Snook direct at page 6)

As to implementation of the EIA, APS proposes to aggregate all of the differences between authorized and actual fixed cost recovery for each customer class included in the adjustor on an annual basis (Snook direct at page 19). This total amount of over or under-recovery of fixed costs will then be allocated to each eligible customer class on an equal percentage basis (Id). In recognition of the fact that not all classes are homogenous APS has included all customer classes in the EIA mechanism, except for the following rate schedules: E-30, E-36 XL, E-

47, E-58, E-59 and Contract 12. (Snook direct at page 16). Mr. Snook states that the annual reconciliation and exemption of some customer classes are consistent with the (Snook at page 19).

**PROBLEMS WITH PROPOSED EIA**

**Q. DO YOU SEE ANY PROBLEMS WITH THE PROPSOED EIA?**

A. Yes. First and foremost, RUCO recognizes that ratepayers prefer not to see too many surcharges on their bills. That observation applies to electric bills, bank statements, credit card bills or cable company bills. Thus, any and all means of avoiding an automatic adjustor mechanism should be examined first.

Second, the Company is simply wrong that its EIA is better suited to respond to growth typically experienced in Arizona. By this the Company means that under its proposed EIA it is allowed to keep any revenue from the growth in the number of customers between rate cases. The idea behind this approach is that the Company must invest in new distribution and generation facilities to serve customers. In this case, however, with the new Schedule 3, the Company's outlay for new distribution facilities will be reduced. Further, the Company is asking for a return on 18 months of post test year pant additions and is requesting any carrying charges for new generating plant be recovered via the ERA.

Third, the Company's rate design proposals are at odds with it statements that it wants to encourage energy conservation. For Residential Service Class E-12 the non time-of-use class, the Company is proposing a 36% increase in the basic service charge and a 3%-6% decrease in energy charges (See SFR Schedule H-3). For the largest residential time-of-use class the Company is proposing a 4% increase in the basic service charge, a 14% increase in the off-peak energy charge and an 8% decrease in the on-peak energy charge (Id). This type of rate design helps the Company recover more fixed charges and makes energy conservation less attractive as it reduces the savings from any energy conservation project. Thus, while APS states it does not want a straight fixed variable rate design to protect its fixed costs recovery it gets exactly that in its proposed decoupling rate design. Thus, the Company's preferred rate design makes the EIA superfluous and acts as suspenders to the rate design belt.

**<u>POLICY QUESTIONS ON ENERGY EFFICIENCY RULES AND DECOUPLING</u>**

**Q. DOES RUCO SUPPORT THE ACC'S ENERGY EFFICIENCY RULES?**

A. Yes.

**Q. DID THE COMMISSION PROMULGATE ITS ENERGY EFFICIENCY STANDARD CONTEMPORANEOUSLY WITH ITS ADOPTION OF ITS POLICY STATEMENT FAVORING DECOUPLING?**

A. No. The Commission adopted its EE Rules before it approved its Decoupling Policy Statement. The Commission approved its Energy Efficiency Rules for electric on July 27, 2010 and approved its Policy Statement on decoupling on December 14, 2010.

**Q. WHY IS THAT IMPORTANT?**

A. The utilities supported and committed themselves to the EE Standard without any certainty that the Commission would take any favorable position on decoupling.

**Q. DOES RUCO OPPOSE A DECOUPLING MECHANISM IN PRINCIPLE?**

A. No. However, RUCO continues to have concerns about whether decoupling will achieve its intended objective of encouraging reduced consumption of electricity. And at this time, in this case, given current economic conditions and current ratepayer opposition, RUCO does not find authorization of the EIA for APS to be in the ratepayers' best interest. Nonetheless, that does not mean RUCO is unalterably opposed to decoupling.

**Q. DOES A DECOUPLING MECHANISM IMPROVE THE FINANCIAL POSITION OF A UTILITY?**

A. Yes. A utility with healthy credit metrics can attract investors and can obtain debt at low interest rates. The utility passes these benefits to the ratepayers through lower rates. Therefore, there may be a time when an asymmetrical, risk shifting ratemaking mechanism, such as decoupling is acceptable. But now is not the time.

It can be argued that a more appropriate time to shift business risk to ratepayer from the utility is when the economy is robust, when unemployment is low, when real estate occupancy is high and the benefit of attracting investors with more than traditional regulatory environment outweighs the additional burden on ratepayers.

Optimally, a decoupling mechanism would provide equal benefits to both the ratepayer and the utility. RUCO believes it is in the interests of consumers to delay building additional infrastructure because the costs of new infrastructure would most likely raise rates higher than the adjustments made through a decoupling mechanism. With decoupling, consumers would pay a little more now (in order to cover the utility's business risk of reduced sales) so as to avoid paying a lot more later for the cost recovery of new plant and infrastructure.

**Q. HAS APS PUT ANY EVIDENCE INTO THE RECORD THAT IT WILL NOT ADVANCE IN GOOD FAITH DSM AND ENERGY EFFICIENCY PROGRAMS TO MEET THE COMMISSION'S EE GOALS UNLESS IT IS GRANTED THE EIA?**

A. No.

**Q. WOULD RUCO EVER SUPPORT A DECOUPLING MECHANISM?**

A. Yes. RUCO is willing to consider the idea that a well constructed, limited and constitutionally sound mechanism that assists the utility in retaining financial health while meeting energy efficiency goals may be in the public interest once the economy recovers.

**Q. PLEASE EXPLAIN WHAT YOU MEAN BY CONSTITUIONALLY SOUND?**

A. This testimony is intended to provide the policy reasons why RUCO opposes decoupling. RUCO's legal and constitutional considerations were expressed in detail in RUCO's Reply Brief in the Southwest Gas rate case, Docket No. G-01551A-10-0458.[4]

---

[4] http://www.azruco.gov/swg_(10-0458)/reply_brief.pdf

That said, RUCO understands **<u>Scates</u>**[5] permits adjusters to recover discrete and identifiable ***expenses***. Here, a decoupling "tracker", "rider", "surcharge" or whatever you want to call it allows the utility to recover lost ***revenues***. RUCO is uncertain whether a court would extend **<u>Scates</u>**-approved recovery of expenses outside of a rate case to lost revenues. Revenues are calculated as part of the utility's authorized operating income. Operating income is calculated by applying the fair value rate or return to the fair value of the utility's assets. Operating income plus operating expenses yields the overall revenue requirement. The second legal concern RUCO posited in Southwest Gas is that RUCO is concerned that a broad revenue decoupling mechanism could enable a utility to overearn and to charge rates that are no longer just and reasonable based on the fair value of the utility's assets determined during the rate case.

## DECOUPLING EXPERIENCE IN OTHER STATES

**Q. HAVE OTHER JURISDICTIONS CONSIDERED DECOUPLING?**

A. Decoupling has had a varied past. States like Washington, Maine and New York adopted decoupling and then dropped it. Maine pioneered a fully decoupled rate design with Central Maine Power in 1991 but faced a recession in the early 1990s. The sudden and sharp downturn in the Maine economy reduced consumption to a

---

[5] See Scates v. Arizona Corporation Commission, 118 Ariz. 531, 578 P.2d 612 (App. 1 1978)

much greater degree than the utility's efficiency efforts and the recession resulted in lower electricity sales. The Decoupling adjustment resulted in an increase in rates reflecting pre-recession target revenues and the adjustments caused rates to go up. Rather than promoting conservation, decoupling became to be viewed as a mechanism that was shifting the economic impact of the recession from the utility to consumers. By 1993, deferrals accumulated to such a high level that Maine Commission and the utility agreed to end the experiment.

In New York, where I was on the Public Utility Commission's Staff, we were both one of the leading Commissions to first adopt decoupling and one of the first to abandon it after rate shock experiences similar to Maine.

**Q. WHAT HAPPENED IN WASHINGTON?**

A. In 1995, the Washington Utilities and Transportation Commission (WUTC) decided to terminate its experimental periodic rate adjustment mechanism (PRAM) for Puget Sound Power & Light, Co. The mechanism was designed to remove disincentives to conservation by decoupling revenues from sales levels and allowing dollar-for-dollar recovery of resource-acquisition costs. The WUTC found that in the 5 years of experience with the PRAM, there were increases in rates in every year and the increases resulted from an extraordinary combination of events: 1) the addition of new power sources, 2) extended drought conditions in the Columbia basin, 3) warmer than average winters, and (4) Puget's initiation of an aggressive conservation program. Under the PRAM's "awkward marriage," the rate impacts of the resource-cost adjustment overwhelmed the rate impacts of the decoupling adjustment, making a fair comparison of decoupling with traditional ratemaking difficult. The WUTC added that neither feature provided a clear incentive for the company to manage its acquisition of supply and demand-side resources at least cost, and that the PRAM shifted some degree of risk from the company to its customers. *Washington Utilities and Transportation Commission v. Puget Sound Power & Light Co.,* Docket No. UE-950618, Sept. 21, 1995 (Wash.U.T.C.).

**Q. ARE YOU AWARE THAT THE VIRGINIA CORPORATION COMMISSION HAS APPROVED DECOUPLING MECHANISMS?**

A. Yes. After the Virginia General Assembly directed the Virginia State Corporation Commission to implement decoupling, the Commission approved decoupling for three utilities, Virginia Natural Gas, Columbia Gas and Washington Gas Light Company. In its 2010 report to the General Assembly, the Virginia Commission expressed concern that these utilities received revenues from decoupling far in excess of lost revenue associated with reduced natural gas sales.

"To illustrate this point, the current actual results indicate that since its inception, VNG's decoupling mechanism has compensated the company approximately $7.7 million for forecasted energy reductions of approximately 18 million Ccfs.

However, VNG's own estimates indicate that its programs have generated actual reductions of less than 491,000 Ccfs, so consumers are paying for a level of energy reductions that are not occurring."

"The results were similar to Columbia's and WGL's programs. Specifically, Columbia's decoupling mechanism enabled it to collect additional non-gas revenue of nearly \$3.2 million based on assumed usage reductions of 8.4 million Ccfs. However, Columbia's engineering estimates indicated that its programs have generated actual reductions of approximately 77,000 Ccfs. WGL's decoupling mechanism enabled it to collect additional non-gas revenue of \$219,275 from ratepayers during a period in which WGL had not yet implemented its conservation and energy efficiency programs."[6]

**Q. WHAT HAPPENED IN DELAWARE?**

A. In 2009, the Delaware General Assembly mandated the Commission authorize revenue decoupled rate designs by the end of 2010. (26 Del. C. §1500(b)(8)) However, during the 2010 legislative session, the General Assembly repealed that mandate. (HB378, Ch. 77:435)[7]

**Q. CAN YOU PROVIDE A SUMMARY OF OTHER STATES EXPERIENCE WITH DECOUPLING?**

A. Yes, below is a summary of some other States experience.

---

[6] http://www.scc.virginia.gov/comm/reports/ngc_rea_09.pdf

[7] http://legis.delaware.gov/LIS/lis145.nsf/vwLegislation/HB+378/$file/legis.html?open

Rhode Island
Narragansett Electric d/b/a National Grid

"Revenue decoupling would protect the Company from revenue declines attributable to any cause, not only energy conservation and efficiency efforts. Decoupling would reduce the company's revenue risk to zero and shift the risk of revenue variations to ratepayers. While the record includes substantial evidence of the benefits of decoupling to the Company the evidence that decoupling will benefit ratepayers is largely speculative. Indeed the record reflects the significant financial impact on ratepayers that decoupling might have. Over the last four years, revenue decoupling would have resulted in an additional $34 million of payments to the Company." (Docket No. 3943, Order at p. 70 dated 1/29/2009)[8]

Nebraska
Aquila

"The revenue normalization adjustment (RNA) is intended to address declining revenues related to decreases in declining usage... Such automatic mechanisms can lead to excessive rates, an inappropriate shifting of risks from stockholders to ratepayers, and decreased incentives to operate efficiently. Therefore, the Commission finds that the rate mechanisms should be denied." (Application No. NG-0041, Order at pp. 20-21 dated 724/2007)[9]

Indiana
Southern Indiana Gas (Vectren)

It would not be equitable to allow Petitioner to recover from its ratepayers for energy savings caused by ratepayers own responsible efforts to conserve...Vectren South's decoupling proposal would allow the Company to recover revenues for reductions in energy consumption that were not caused by its conservation efforts. Vectren South's proposal is for "full" decoupling, which means that it will recover its lost margin regardless of causation." (289 PUR 4th 9, 2011 WL 1690057, April 27, 2011, Order at pp. 85-86)[10]

---

[8] http://www.ripuc.org/eventsactions/docket/3943-NGrid-Ord19563(1-29-09).pdf

[9] http://www.psc.state.ne.us/home/NPSC/natgas/orders_natgas/pdf_orders_natgas/NG0041070724.pdf

[10] http://www.in.gov/iurc/files/Cause_No._43839.pdf

Montana
NorthWestern Energy

After originally approving decoupling for electricity with a reduced ROE but denying decoupling for natural gas in 2009, the Commission eliminated decoupling for NorthWestern's electric utility without any change to its previously approved reduced ROE. (Docket No. D2009.0.129 / Order No. 7046i, June 30, 2011, Order at p. 58)[11]

Tennessee
Piedmont Natural Gas

Had the mechanism been in place since Piedmont's last rate case in 2003, Piedmont's revenues would have grown by $19 million. "The panel found that Piedmont failed to present sufficient evidence to justify a need for a new financial incentive in order to comply with state and federal law regarding conservation while earning a just and reasonable rate of return. The Authority must be able to determine the benefit to consumers before permitting Piedmont an additional financial incentive." (Docket No. 09-00104, June 9, 2010, Order at pp. 5, 12)[12]

Connecticut
Yankee Gas Company

Yankee did not propose a decoupling mechanism because of recent Department Decisions. Yankee contended that it has satisfied the decoupling requirement stated in Conn. Gen. Stat. 16-19tt through its proposed rate design. More specifically, proposed rates in both RY1 and RY2 exhibit a slight increase in fixed cost recovery. (Docket No. 10-12-02, June 29, 2011, Order at p. 168)[13]

---

[11] http://psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2009-9-129_7046i.pdf

[12] http://www.state.tn.us/tra/orders/2009/0900104cg.pdf

[13] http://nuwnotes1.nu.com/apps/financial/nuinvest.nsf/0/552D929F0B8C6FB2852578BF004639C5/$FILE/Yankee%20Gas%202011%20final%20rate%20decision.doc

Connecticut Light and Power

The AG, Wal-Mart, the Connecticut Industrial Energy Consumers (CIEC) and the Office of Consumer Counsel (OCC) all opposed decoupling. Wal-Mart found decoupling would result in rate changes that are inversely proportional to customer efficiency efforts so as customers implement more energy efficiency, the rate increases. Plus, decoupling sends counterintuitive price signals through increased rates even through substantial efforts were undertaken to reduce energy consumption. "Based on the evidence in this proceeding, the Department finds that it is reasonable to maintain decoupling for CL&P through rate design. Therefore, CL&P's proposal is denied." (Docket No. 09-12-05, June 30, 2010, Order at pp. 165-174)[14]

Connecticut Natural Gas

"The Department agrees with the OCC and AG" that decoupling shifts business risk from the utility to customers and that decoupling actually creates a disincentive for customers to pursue conservation and load management programs by denying the full bill reduction benefits of their conservation efforts. (Docket No. 08-12-06, June 30, 2009, Order at pp. 75)[15]

**Q DOES EVERY UTILITY ENDORSE DECOUPLING?**

A. No. Southern Company is the parent company for Georgia Power, Mississippi Power, Alabama Power and Gulf Power. It has 4.4 million customers in four states. In its second quarter 2009 earnings call, Southern Company's Chairman, President and CEO, David Ratcliff stated:

---

14 http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/08d20a020e13c584852577b6005de25b/$FILE/091205-063010.doc

15 http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/8686a942e19151288525765b004bbd27/$FILE/081206-063009.doc

"But fundamentally, we don't think that the decoupling concept works in our regulatory environment. And fundamentally, I've said I don't particularly like the notion. I think there is good reason to keep the cost of the product connected with the use of the product and make sure that our customers are as informed as we can possibly make them about how to use a product and the service efficiently and effectively to control their costs. I like that model a lot better than I like disconnecting what I thought ought to go together."[16]

**Q. SO WHAT DOES RUCO WANT THE COMMISSION TO LEARN FROM THIS REVIEW OF DECOUPLING IN OTHER STATES?**

A. This review shows that "decoupling fever" is not an epidemic nor is it a be all and cure all to encourage energy efficiency. Several other jurisdictions have rejected decoupling for the very reasons that RUCO opposes it in this docket. Furthermore, states that have at one time embraced decoupling have now distanced themselves from it. (Maine, Montana, Delaware and Virginia).

**<u>RUCO'S REASON FOR OPPOSITION TO DECOUPLNG AT THIS TIME</u>**

**Q. WHAT IS THE MAIN REASON THAT RUCO OPPOSES DECOUPLING AT THIS TIME?**

A. As RUCO has articulated in the recent Southwest Gas and UNS Gas cases, it is because decoupling shifts risk of Arizona's poor economy, with its slew of vacant housing and closed businesses for the utility to ratepayers. Another way to say it

---

[16] http://seekingalpha.com/article/152321-southern-company-q2-2009-earnings-call-transcript?part=qanda

is that decoupling recession proofs the utility. Decoupling also takes other risks away from the utility such as lost sale due to cooler than normal weather, storms or as just recently occurred lost sales due to operational error. RUCO believes that there are much better alternatives to encourage conservation without decoupling. Even without ratepayer and utility benefits being on “equal footing”, RUCO finds there may be an indirect benefit to ratepayers in that decoupling provides the utility with increased financial stability from reduced business risk and a nearly-guaranteed rate of return. However, when the economy is stalled like it is today, this indirect benefit is not enough for the consumers and RUCO cannot support the EIA. Furthermore, as stated previously, there are other ratemaking alternatives that provide the utility with sound financial metrics without shifting risk to the ratepayers.

**Q. PLEASE EXPLAIN.**

A. Under a well-constructed decoupling mechanism, the utility would implement robust and cost effective energy efficiency programs and individual ratepayers would use less energy and enjoy reduced monthly bills. Reduced consumption would delay the need to build new and very expensive generation, transmission and other infrastructure. A decoupling mechanism would hold the utility harmless for the lost revenue associated with reduced consumption and allow it to cover its fixed costs. In the end, the added revenue paid by the ratepayers through the decoupling mechanism would be vastly outweighed by the deferred costs to build new plant and corresponding infrastructure.

**Q. WHY ISN'T THAT THE CASE HERE?**

A. Aside from the investment in the Az Sun program the vast majority of rate base investment being made by this Company is for distribution related plant. Utilities defer construction of new distribution plant when there are no new customers. No amount of reduced consumption by current ratepayers will defer the need for new distribution infrastructure for new customers. The construction of new infrastructure is based entirely on the need for new distribution service to new customers and not to meet the needs of existing customers.

**Q. WHY IS THE STATE OF THE ECONOMY A MAJOR FACTOR IN RUCO'S OPPOSITION TO DECOUPLING IN THIS RATE CASE?**

A. RUCO contends that it is not in the public interest to implement decoupling during a time of economic uncertainty and stress.

Arizona families are suffering. Arizona has one of the highest home foreclosure rates in the nation and has the unenviable status of an unemployment rate exceeding the national average. A staggering 20% of Arizona's population lives at or below the poverty level. The percentage of residential ratepayers participating in CARES is six point three (6.3) percent. Maine's PUC eliminated decoupling after residents voiced their opposition for having to cover the utilities' business risks in the middle of the economic recession of the 1990s. And the same complaints are being expressed to the Commission in the Public Comment meetings for the Southwest Gas and this APS rate case.

As the Commission has heard from retirees in recent public comment sessions, unstable and weak market performance has decimated the value of many retirement investment portfolios. While retirees did everything right to save for their retirement years, the poor economy and the absence of cost of living increases in Social Security, make their financial futures uncertain.

From this perspective, RUCO argues that shifting a utility's business risk on to ratepayers at this time is unfair.

In times such as these, most ratepayers' efforts to reduce their bills have little to do with the commendable goal of preserving our natural resources or limiting future utility infrastructure. Ratepayers need their bills to be as low as possible because they need to shift those savings to other costs – like paying the mortgage or covering increased food costs. This is the type of "shift" the ratepayers are trying to do. They should not have to share the savings from their efforts with the utility because the utility wants to shift its risk on to them.

In addition to filing testimony in the Southwest Gas case on behalf of Staff, Dr. David E. Dismukes has been an expert witness against decoupling in several other jurisdictions. In Tennessee, Dr. Dismukes provided testimony on why consumption decreases during poor economic times. RUCO agrees with his statement and adopts its spirit as its own:

"Decreases in sales associated with economic downturns have nothing to do with energy efficiency programs offered by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times or, alternatively, businesses and industries idling or shutting down their operations. Under revenue decoupling, ratepayers would be required to make a utility whole for revenue losses during these economic downturns, whereas under traditional regulation, utilities bear the risks of these economic contractions, just like many other types of businesses and industries." (Dismukes testimony, p. 65, Chattanooga Gas Company, Docket No. 09-00183)[17]

In Arizona many, many businesses have shut their doors. Commercial real estate vacancy rates are very high. And Arizona's home foreclosure rate is one of the highest in the country. These empty dwellings have contributed to the reduced electric consumption. And economic forecasts do not show significant improvement in the near future. So it is inherently unfair for APS electric

[17] http://www.tn.gov/tra/orders/2009/0900183bs.pdf

customers to pay a decoupling charge that contains the effects of the real estate bust embedded in it. Not only would customers pay for cost effective and successful DSM/EE programs, but they would also be shielding the utility from the impact of shuttered businesses and empty homes.

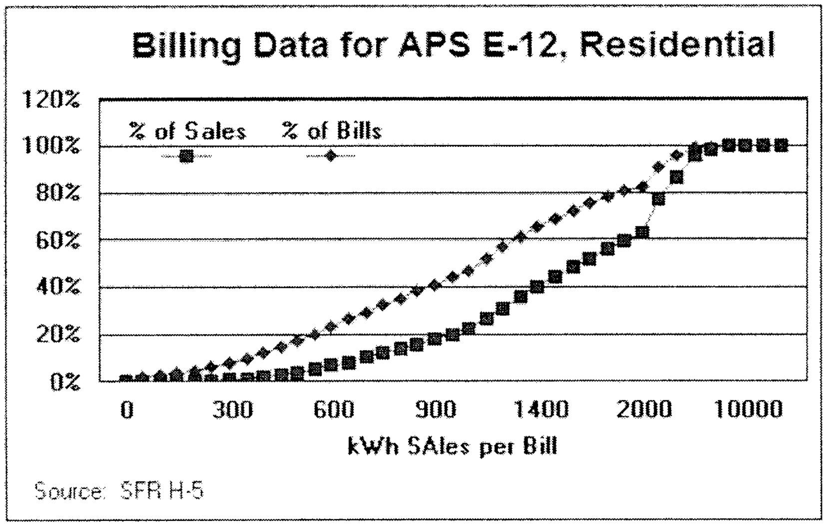
**RUCO ALTERNATIVES TO DECOUPLING**

**Q. PLEASE SUMMARIZE RUCO'S TWO ALTERNATIVES TO DECOUPLING?**

A RUCO provides two options for consideration, a rate design option and a return on equity premium.

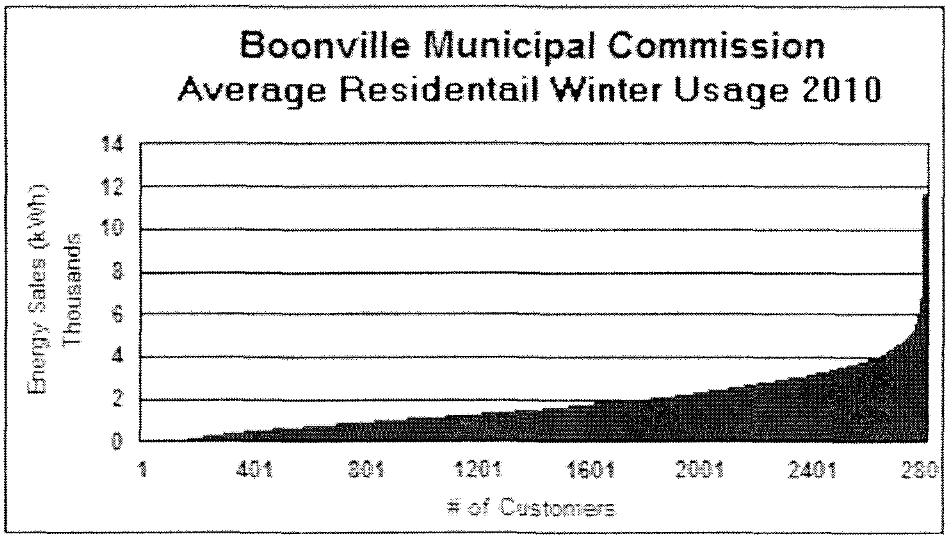
**Q. PLEASE EXPLAIN THE RATE DESIGN OPTION?**

A. The rate design option recognizes that for a large portion of the customers electricity usage is not a true variable that they whimsically use. Rather it is an everyday part of their lives which for the most part they do not try and directly control. For example the refrigerator runs 24 hours a day, the television is watched at night, the clock radio is always plugged in, etc. There are certainly opportunities to shift usage away from the peak period and APS already has approximately 50% of their residential users on time of use rates. While there are opportunities for energy conservation these opportunities are generally one time events, a new more efficient refrigerator is purchased, an electric water heater is wrapped, etc. These savings generally result in new appliance standards and take place over time. As illustrated by the chart below for the E-12 Residential Class approximately 50% of the bills are for 1,000 kWh or less per month and this 50% accounts for only 22% of total sales. On the other hand, 20% of the bills are for usage above 2,000 kWh per month and they account for 40% of the sales.




This observation tells two things. Most users are relatively small and their usage relatively constant but there are a few large users that use most of the energy. Said another way, even though the rate design recovers costs from both a fixed charge and a variable charge, the revenues received from most bills is relatively constant but there are some large users whose usage will change with weather.

This observation holds true if the utility is a summer peaking utility in the American Southwest or a winter peaking utility in upstate New York. The chart below is a graph of average winter usage for the electric customers of the Boonville Municipal Commission located in Boonville, New York. Located not far from the snow belt of the great lakes, Boonville's nickname is the Snow Capital of the East and is considered a snowmobiling destination. Boonville is located in what is known as the New York "North Country" where winter temperatures reach 25 below zero on a not uncommon basis. Boonville is also one of the 47 municipal utilities in New York State which get the majority of their power from Niagara Power Project located at Niagara Falls. The Niagara Power Project was built in the early 1960s. It has its construction bonds paid off and sells power at costs which is currently about 1.1 cents per kWh... In fiscal year 2010, the Municipal Commission of Boonville sold power at an average retail rate of 4.2 cents per kWh. At rates this low many people use electricity to heat their homes and some user's average over 14,000 kWh per month during the winter period. That said, however, as illustrated by the chart below the usage patterns of the customers of the Boonville Municipal Commission is very similar to the customers of APS; the majority of customers are relatively small users with a discreet few using a large amount of the energy.




The RUCO rate design option takes advantage of the fact that most users are small and the vast amount of revenues collected by the utility are from these small users. This allows the rate designer to place more revenue into the fixed monthly minimum and lower usage rate blocks and provides a more stable and assured revenue stream for the utility. At the same time, one can increase the tail block rate and encourage large users to conserve. Thus, regardless of its DSM/EE efforts, APS will continue to collect a larger portion of its revenue requirement in its monthly minimum. RUCO notes that this Commission has approved shifting more revenue into the fixed charge as an acceptable method of addressing lost revenue due to reduced consumption in the previous Southwest Gas (Decision No. 70665) and UNS Gas (Decision No. 71623) rate cases. RUCO proposal is consistent with past Commission decisions.

While RUCO is still in the process of finalizing its rate design testimony and rate design to be filed on December 2, 2011, the table below illustrates the rate design concept outlined above for E-12, the Residential non-time of use service class. This rate design was developed based on the assumption that the RUCO recommended no net rate change proposal would be adopted in this case and that any rate design developed would need to be revenues neutral.

| **Bundled Rates** | **Present** | **RUCO Proposed** | **% Change** |
|---|---|---|---|
| **Summer** | | | |
| Days $/day | $ 0.285 | $ 0.299 | 5.00% |
| First 400 kWh | $ 0.09671 | $ 0.09574 | -1.00% |
| Next 400 kWh | $ 0.13739 | $ 0.13602 | -1.00% |
| Next 2200 kWh | $ 0.16281 | $ 0.16118 | -1.00% |
| Remaining kWh | $ 0.17358 | $ 0.20520 | 18.22% |
| **Winter** | | | |
| Days $/day | $ 0.285 | $ 0.299 | 5.00% |
| All kWh | $ 0.09397 | $ 0.09303 | -1.00% |

As can be seen from this table, there is a small increase in the basic service charge which has effect of increasing it form $8.64 per month to $9.05 per month but a large increase in the tail block rate.

**Q. PLEASE EXPLAIN RUCO'S OTHER ALTERNATIVE – PROVIDING A COST OF EQUITY "PREMIUM".**

A. Many states have debated whether to lower a utility's authorized cost of equity in recognition of reduced business risk associated with a decoupling mechanism. The argument is that since decoupling shifts risk away from the utility and onto the customer, that reduction in risk should be reflected in the utility's authorized cost of equity. For example, in Nevada, Southwest Gas admitted that a decoupling mechanism reduces risk and the Commission reduced its authorized return on equity by 25 basis points. (Docket No. 09-04003, Order at p. 15)

**Q. WHY IS A FIVE (5) BASIS POINT INCREASE AN APPROPRIATE INCREASE?**

A. RUCO has reviewed Orders in other jurisdictions that have decreased the authorized cost of equity to adjust for decreased risk from decoupling. RUCO finds there is an arguable correlation between the amount of reduction taken in consideration of decoupling and a risk premium absent decoupling. In Southwest Gas's recent Nevada rate case, it argued that a 10 basis point adjustment to reduce risk was appropriate:

"Southwest provided the results of a survey of 26 gas decoupling programs and how regulatory agencies have treated ROE in the context of reduced risk...Every state commission that has considered the risk implications of revenue decoupling concluded that decoupling reduces risk. ROE reductions that have accompanied decoupling range from 0 basis point to 25 basis points with a simple average reduction of 12.5 basis points...Southwest acknowledged that while decoupling does reduce risk, there is no way to empirically quantify its effect." (Order in Docket No. 09-04003, pp. 10-11)

**Q. BUT DOESN'T ARIZONA'S POLICY STATEMENT STATE THAT A COST OF CAPITAL ANALYSIS SHOULD NOT CONSIDER REDUCED RISK IF DECOUPLING IS IMPLEMENTED?**

A. Yes, and so does APS in its application. So arguably if there is no need to reduce the ROE when approving decoupling, then there is no need to increase the ROE when denying decoupling. However, RUCO does believe that its proposal to include an ROE premium is reasonable and helps the utility attract investors and maintain healthy financial metrics while implementing cost effective energy efficiency programs.

**Q. DOES THAT CONCLUDE YOUR ADDITIONAL DIRECT TESTIMONY?**

A. Yes it does.

EXHIBIT
RUCO
3

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

BEFORE THE

ARIZONA CORPORATION COMMISSION

RATE DESIGN TESTIMONY OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

December 2, 2011

# TABLE OF CONTENTS

**EXECUTIVE SUMMARY**
**ARIZONA PUBLIC SERVICE COMPANY**
**DOCKET NO. E-01345A-11-0224**

My testimony addresses the Company's proposed revenue allocation, rate design, proposed revisions to plans of administration and changes in the presentation of bills.

In direct testimony presented on November 18, 2011 RUCO recommended that there be no net change in the overall rates for Arizona Public Service. Absent any showing of need to dramatically realign rates amongst rate classes, RUCO proposes that each service class receive no net increase at this time.

For the Residential Service Class the Company is proposing above average increases in the basic service charge when there is no overall increase being given to the Company as a whole. This is unfair to small users. It is also irrational from an energy conservation perspective because to do this requires that many of the energy will decrease. This is not the right price signal to give to customers if you really want them to conserve. While in the interest of protecting the Company's fixed cost recovery but at the same time encouraging energy conservation RUCO proposes to limit the increase in the basic service charge to no more than 10%. In addition, RUCO would increase the energy charges for the on-peak period by 5% for the time-of-use rate schedules as well as a 5% increase in the last block for the non-time-of-use rate schedules. The remaining revenue requirement will be recovered through the remaining energy charges.

For the Low Income customers the Company proposes to give an above average increase in order to close the gap between the rates charged to low income versus non low-income. While RUCO supports simplifying and streamlining these rate structures as well as the idea of closing some of the gap between the low-income and non-low income customers, it cannot support allocating an above average increase to these customers at a time as that would result in only the low income customers receiving a rate increase from this rate filing. As such, RUCO believes that the rate redesign should wait until the next major rate case.

On rate design, the Company proposes a variety of increases and decreases to demand and energy rates that, as a whole, results in bill increase that are almost equal for all customers. The average increase to the General Service Class is 2.6% and under the Company's proposal rate increases generally range between 2.0 and 4.0 %. Based on these bill impacts I recommend approval of the Company's approach to design and have implemented it in my design as well.

The Company proposes to eliminate the minimum contract demand charge for most General Service rate classes. The minimum contract demand charge is to protect the recovery of the Company's fixed costs. At a time when the Company is increasing its efforts on energy conservation this is the worst time to eliminate this charge. As to Company's argument that this will lead to bill simplification and being customer friendly the minimum contract demand charge is easily understood and is a very common rate design for general service customers and has been in use for decades.

The Company proposes to eliminate rate schedule E-53 – Service for Athletic Stadium and Sports Fields, as it is only there to protect the customers under this rate schedule from the minimum contract demand charge. Since I oppose the proposed elimination of the contract demand charge, the elimination of the E-53 rate schedule is unnecessary.

Rate Rider Schedule E-54 – Seasonal Service eliminates or reduces the alternative minimum bill for customers with seasonal loads. The Company proposes to reduce the applicability of this rate schedule as it proposes to eliminate the minimum contract demand charge. Since I oppose the proposed elimination of the contract demand charge, the elimination of the E-54 rate schedule is unnecessary.

The one exception to equal average increase in rates for the General Service Class is for E-32 – Large. The result of the Company's proposed rate design is to increase the demand charge dramatically and leave the average energy charge essentially unchanged. This gives a dramatic increase in rates to low load factor customers, a 29% increase, but with almost no increase for the high load factor customers. The company has not provided enough justification for such a dramatic increase in rates.

The Company is proposing several new rate offerings that will increase customer choice and rate options. Rate design is a very effective way to induce customers to be conscientious of their energy use and these new programs would complement the Company's efforts to control load through rate design options. RUCO supports the programs and recommends their approval.

The Company has proposed a whole series of changes to a variety of rate schedules, riders to rate schedules, and service schedules. These changes generally apply to a certain types of customers, or specific end uses or customer circumstances and are considered housekeeping change that will result in more accurate billing or fine-tune the applicability of a service class while having little or no impact on other customers. RUCO supports the modifications.

The Company proposes to remove all transmission charges from base rate and have them recovered in a separate Transmission Cost Adjustment. RUCO believes that adjustor mechanisms are unwarranted unless the costs revered through the adjustor are highly volatile and beyond the Company's ability to control. RUCO does believe that the Company has shown that transmission costs to be highly volatile or beyond its control. In addition, while RUCPO recognizes that Commission Staff is a party to a FERC proceeding, this is not the same as have full regulatory authority when issues come before the Arizona Corporation Commission. On both these grounds, RUCO opposes the change.

The Company proposes to simplify customers' bills by removing much of the detailed data which confuses customers. Given that revision to the bill would not hamper any effort to resurrect retail competition in Arizona RUCO has no problem with the general concept that the Company proposes. That said, however, delineating the DSM and RES adjusters are entirely different issues. These charges have nothing to do with bundled or unbundled services relating to retail competition. They are charges for programs ordered by the Commission and they are not inherent costs of providing electrical service. It is RUCO's position that there should be full transparency of the cost of these programs and these charges should be delineated on the bill.

RUCO also opposes moving any more energy efficiency program costs from the Demand Side Management Adjustment Clause to base rates as some parties are proposing. RUCO supports full disclosure of the cost of energy efficiency and believes that moving cost recovery to base rates would result in less transparency of the cost of major policy goals.

**INTRODUCTION**

**Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Frank Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding utility industries 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 SUBMITTED TESTIMONY IN THIS PROCEEDING?**

A. Yes.

**Q. WHAT IS THE PURPOSE OF YOUR ADDITONAL DIRECT TESTIMONY?**

A. I will discuss the revenue allocation and rate design based on RUCO's direct case that there should be no net increase in rates.

...

...

...

...

## REVENUE ALLOCATION

**Q. PLEASE DISCUSS HOW THE COMPANY ALLOCATED REVENUES AMONG CLASSES?**

A. As shown on SFR Schedule H-1 the Company's proposed revenue allocation was driven by both rate impacts and cost of service considerations. In its direct case APS requested an overall increase in retail base rates of 3.3% and proposed to increase residential rates by 3.95%, increase rates for general service by 2.64%, increase rates for water pumping service by 3.62% and increase rates for dusk-to-dawn lighting by 2.94% and increase rates for street lighting service by 3.62%.

In its testimony, APS states that the cost of service and resultant rates of return and revenue deficiencies served as a general guide in allocating the overall increase to the various rate classes. In addition, the Company considered gradualism, where the intent is to moderate the impact on any single customer class, in making the final recommendation.

**Q. WHAT DOES RUCO RECOMMEND?**

A. Based on a very tight range of rate increases proposed by the Company – a low of a 2.6% increase and a high of 4.0% compared to the overall average increase of 3.3%, corrections for cost of service considerations were outweighed by rate gradualism considerations. RUCO supports this concept and proposes that each service class receive the same net average increase of $0.

## RESIDENTIAL RATES

**Q. WHAT RATE PLANS ARE AVAILABLE TO RESIDENTIAL CUSTOMERS?**

A. The Company's rate design offerings for residential customers can be described as essentially two general rate plans: non-time-of-use and time of-use. Rate Schedule E-12 – Residential Service is a non-time-of-use rate plan with an inclining block rate structure with four blocks. The last block or "tail" block is for usage over 3,000 kWh per month and has a base rate of 17.4 cents/kWh. An inclining block rate tries to incent customers to use less each month. The Company currently serves nearly 450,000 customers under this rate plan (See SFR Schedule H-2).

There are five time-of-use rates rate classes: ET-1 – Residential Time-Of-Use, ECT-1R – Residential Time-Of-Use with Demand Charge, ET-2 Residential Time-Of-Use, ECT-2 -- Residential Time-Of-Use with Demand Charge and ET-SP -- Residential Time-Of-Use with Super Peak Pricing. Rate Schedules ET-1 and ECT-1R have been frozen to new customers since January 1, 2010. At the end of the 2010 test year there were 504,592 residential customers served under time-of-use rate schedules with 341,998 still served under the now frozen rate offering.

The Company also offers five rate plans for low-income customers, which mimic the non-low-income rate schedules but have discounts; a critical peak pricing rate rider (rate rider schedule CPP-RES); three green power rate riders; two solar rate riders; rate riders for renewable generation; and optional rates for dusk-to-dawn outdoor lighting. These rate riders round out the offerings made by the Company and add to an already healthy mix of rate options for customers.

**Q. WHAT CHANGES IS APS PROPOSING FOR THE RESIDENTIAL RATE SCHEDULES?**

A. Overall the company is allocating a slightly higher than average increase to the residential rate schedules than average, 3.95% to residential versus 3.33% overall (see SFR Schedule H02). As to rate design, the most striking feature of the Company's proposal is that it seeks to dramatically increase the basic service charge for all residential rate schedules and either decrease energy rates or give a very small increase in energy rates. This rate design philosophy holds true for all residential rate classes. By doing this, the Company is placing almost all of the base rate increase to small users. For example, under the Company's proposal a 100 kWh customer is the E-12 rate schedule will receive a 17% increase in rates while a customer using 2,000 kWh per month would see a 0.8% rate increase (see RUCO Schedule H-4, E-12 Sum). Similarly, for a 100 kWh customers under ET-2, the customer would receive a 2.7% increase while the 2000 kWh customers would see a 1% rate decrease (see RUCO Schedule H-4, ET-2, Sum)

**Q. HOW MUCH DOES THE COMPANY PROPOSE TO INCREASE THE BASIC SERVICE CHARGE FOR RESIDENTIAL RATES?**

A. The current bundled basic service charge for residential customers varies by rate schedule from \$0.285 to \$0.556 per day, which on average is about \$8.67 per month for rate E-12 and \$16.91 per month for the other residential rates. APS proposes to increase the bundled basic service charge to approximately \$11.86 per month for rate E-12 and \$17.61 for the other residential rates (Miessner direct at page 8). The Company states that the above average increases in the basic service charge is given to better reflect the changes in cost of service that the Company has been experiencing over time (Id).

**Q. WHAT DO YOU RECOMMEND?**

A. Giving an above average increase in the basic service charge when there is little or no increase being given to the energy rate is unfair to small users. It is also irrational from an energy conservation perspective because to do this requires that all energy charges for the E-12 rate schedule will go down under the

Company's proposal. This is not the right price signal to give to customers if you really want them to conserve.

While in the interest of protecting the Company's fixed cost recovery but at the same time encouraging energy conservation RUCO proposes to limit the increase in the basic service charge to no more than 10%. In addition, RUCO would increase the energy charges for the on-peak period by 5% and the top block for the E-12 rate schedule (and its subclasses) by 5% as well. The remaining charges would be recovered through the remaining energy charges.

**LOW INCOME DISCOUNT**

**Q. PLEASE DESCRIBE THE RESIDENTIAL LOW INCOME RATES.**

A. Low income customers can qualify for Energy Support Program (E-3) or Medical Care Equipment Program (E-4) which can offer up to 40% off the cost of power. The reduction varies depending on how much electricity is used each month and E-3 and E-4 customers are exempt from Power Supply Adjustor ("PSA") charges and the Demand Side Management Adjustment Clause ("DSMAC"). Once a customer is qualified as E-3 or E-4, APS currently offers five residential low-income rate schedules: E-12, ET-1, ECT-1R, ET-2, and ECT-1R each have a low-income subclass. These rate plans are similar to the non-low income versions, except that they have lower prices because they were exempted from the last general rate increase.

Company witness Miessner reports that the low-income base rates are currently about 13% lower than other residential rates, for a savings on their total bill of about 11%, prior to any other discounts or exemptions (Miessner direct at page 10). Coupled with the low-income discount and adjustor exemptions, participants can save from 13% to 46% per month or more on their total bill (Id). There were 62,580 customers served under the low-income rate schedules in the test year and this represents 6.3% of all residential customers (SFR Schedule H-2).

**Q. IS APS PROPOSING AND RATE DESIGN CHANGES FOR LOW INCOME CUSTOMERS?**

A. Yes. The Company proposes to give an above average increase to low income base rates to close a portion of the 13% discount from the base rates of the parent residential service class (Miessner direct at page 10). This reduction in discount is done by giving an extra 3.0%-3.6% more to the low-income service classes (Id). For example, APS requests to increase Rate Schedule E-12 by 3.37%, and Rate Schedule E-12 Low Income by an additional 3.6%, or 7.01% total increase (Id).

APS proposes to re-design the low income and medical equipment discounts in Rate Rider Schedules E-3 and E-4. The current E-3 and E-4 discounts differ by rate block and are somewhat complicated to explain to customers (Miessner direct at pages 10-11). The Company is proposing a single percentage discount of 25%, with a monthly cap of $18 for participants in the E-3 Energy Support Program and a cap of $36 for the E-4 Medical Care Equipment Support Program (Id).

Finally, the Company proposes to eliminate the low-income exemption for Adjustment Schedules PSA-1 and DSMAC-1. The former recovers the costs of fuel and purchased power that are not recovered in base rates (Miessner direct at page 12). The latter recovers the costs of energy efficiency and demand response programs that are not funded through base rates (Id). APS believes that these exemptions are piecemeal and inappropriate in that all customers should fund these costs (Id).

**Q. HAS APS EXPLAINED WHY IT IS MODIFYING THE LOW INCOME DISCOUNTS?**

A. Yes. As explained by Company witness Miessner, while the savings are beneficial to low income customers that qualify under the programs, the Company believes that discounts that apply to only some customers can create fairness issues with other residential customers (Miessner direct at page 11). This fairness issues including other residential customers who are financially distressed, but not enough so to qualify for the rates, and who must pay for these savings through higher monthly bills (Id).

**Q. WHAT DO YOU RECOMMEND?**

A. While RUCO supports simplifying and streamlining these rate structures as well as the idea of closing some of the gap between the low-income and non-low income customers, it cannot support allocating an above average increase to these customers at this time as that would result in only the low income customers receiving a rate increase at this time. As such, RUCO believes that the rate redesign should wait until the next major rate case.

**<u>GENERAL SERVICE RATES</u>**

**Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN CHANGES FOR THE GENERAL SERVICE RATES.**

A. General Service rates apply to non-residential customers. General Service customers include government entities, hospitals, schools, retail stores, offices, manufacturers, restaurants, warehouses, and other business customers. The rate classes for General Service customers are grouped by size monthly loads less than or equal to 20 kW; small – 21 to 100 kW; medium – 101 to 400 kW; large – 401 to 3,000 kW; and extra large – greater than 3,000 kW and by non-time-of-use and tine-of-use rates. The non-time-of-use rate schedules are standard Rate Schedules E-32 XS (extra-small), E-32 S (small), E-32 M (medium), E-32 L (large), E-34 (extra large). The time-of-use rate schedules are E-32TOU XS, E-32TOU S, E-32TOU M, E32TOU L. The Company also offers, separate rate classes for schools: GS-Schools M, GS-Schools L, and E-35 (extra large). Finally the Company offers some special general service rate classes rate schedule E-30 for extra small unmetered loads, rate schedule E-53 for sports field and stadium lighting, rate schedule E-54 for seasonal service and rate schedule RSSP, a rural schools solar program.

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RATE CHANGES TO THE GENRAL SERIVCE RATE SCHEDULES.**

A. The Company proposed a rate increase to the General Service class that was slightly less than the requested increase for the Company as a whole, 2.64% percent versus 3.33% respectively (See SFR schedule H-2). The lower than average increase reflects the fact the General Service classes are providing a higher than average rate of return based on the Company's cost of service study as presented by Company witness Fryer. Mr. Fryer's cost of service study shows that the General Service class is earning an 11.86% rate of return versus the

8.86% rate of return earned by the Company overall in the test year (see Zachary Fryer Workpaper 1).

**Q. PLEASE DISCUSS THE COMPANY'S GENRAL APPROACH TO THE RATE DESIGN FOR THE GENERAL SERVICE CLASS.**

A. On rate design, the Company proposes a variety of increases and decreases to demand and energy rates that, as a whole, result in bill increases that are almost equal for all customers. The average increase to the General Service Class is 2.6% and under the Company's proposal rate increases generally range between 2.0 and 4.0 %. The only exception to that is for small E-32 Large who is receiving a large increase (approximately 25% in the summer) for low load factor users due to a realignment of the rate structure. I object to that rate design change and will discuss supra and recommend approval of all of the other of the Company's rate design proposals (i.e., increasing basic service charge based on new cost elements and recovering all other charges on an equal percentage basis).

Other significant rate design proposals are the elimination of the monthly contract minimum charges for certain rates; modify Rate Schedule E-32 L; cancel Rate Rider Schedule E-53; modify Rate Rider Schedule E-54; and add two new provisions for Rate Schedule E-30 (Miessner direct at page 15). The Company also proposes to alter the time-of-use rates for schools, GS-Schools M and GS-Schools L (Id). Each proposal is discussed below.

## MODIFCATION TO MONTHLY CONTRACT MINIMUM CHARGE

**Q. PLEASE DISCUSS THE ELIMINATION OF THE MONTHLY CONTRACT MINIMUM CHARGE?**

A. A monthly contract minimum charge is a floor for a monthly bill whereby if the usual monthly bill calculation results in an amount that is less than the alternative minimum calculation, then the customer is billed the minimum amount. The purpose of a floor charge is to protect the Company's recovery of its fixed costs (Miessner direct at page 17). The Company is proposing to eliminate the minimum bill provisions in Rate Schedules E-32 S, E-32 M, E-32 TOU S, and E-32 TOU M, but retain them for the large and extra-large general service rates (Id). The Company argues that this proposal will simplify the rates, make them more customer friendly, and cut down on bill inquiries and the concomitant operational costs without unduly creating a risk of shifting wires costs to other customers (Id). In addition, Mr. Miessner states that relatively few customers and load for the small and medium rates were actually billed under the minimum provision during the test year (Id). Furthermore, Mr. Miessner states that because the customers on these rates are all less than 400 kW of load, he does not believe that eliminating the minimum provision will actually or potentially create any material risk of cost shifting to other customers (Miessner direct at page 18).

**Q. DO YOU AGREE WITH ELIMINATING THE MINIMUM CONTRACT DEMAND CHARGE?**

A. No. As Company witness Leland Snook testifies most of the Company's charges are fixed. The exact purpose of the minimum contract demand charge is to protect the recovery of the Company's fixed costs. At a time when the Company is increasing its efforts on energy conservation this is the worst time to eliminate this charge. As to argument about bill simplification and the change being customer friendly, the minimum contract demand charge is easily understood and is a very common rate design for general service customers and has been in use for decades.

## PROPOSED ELIMINATION OF RATE SCHEDULE E-53

**Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO ELIMINATE RATE RIDER SCHEDULE E-53?**

A. Rate Rider Schedule E-53 – Service for Athletic Stadium and Sports Fields, is applicable to outdoor athletic stadiums and sports fields operated by schools, churches or municipalities. All provisions of the applicable general service rate schedule will apply except that in the months when no service is used, no bill is rendered. The Company believes that the Rate Rider Schedule E-53 is no longer necessary given the proposed elimination of the minimum bills for certain general service rates discussed above. As Mr. Miessner explains, E-53 essentially eliminates the alternative minimum bill calculation for sports field lighting loads – the alternative minimum kW charge and basic service charge – when the lights are not in use for a billing month (Miessner direct at page 18). Thus, elimination of the contract demand minimum charge eliminates the need for E-53 (Id).

**Q. WHAT DO YOU RECOMMEND?**

A. As I oppose the elimination of the contract demand charge, the elimination of the E-53 rate schedule is unnecessary.

**PROPOSED ELIMINATION OF RATE RIDER SCHEDULE E-54**

**Q. WHAT DOES THE COMPANY PROPOSE FOR RATE RIDER SCHEDULE E-54?**

A. Rate Rider Schedule E-54 – Seasonal Service eliminates or reduces the alternative minimum bill for customers with seasonal loads, such as agricultural process customers where their usage occurs mainly in the spring and fall and is minimal in the summer. The Company is proposing to make Rate Rider Schedule E-54 only applicable to customers served under Rate Schedule E-32 L because the rider is no longer necessary for Rate Schedules E-32 S and E-32 M in light of the proposed elimination of the alternative minimum bill for these rates (Miessner direct at page 19).

**Q. WHAT DO YOU RECOMMEND?**

A. As I oppose the elimination of the contract demand charge, the elimination of the E-53 rate schedule is unnecessary.

**PROPOSED MODIFICATION TO RATE SCHEDULE E-32 L**

**Q. HOW DOES THE COMPANY PROPOSE TO MODIFY RATE SCHEDULE E-32 L?**

A. This rate schedule is for general service customers whose monthly loads are greater than 400 kW per month. The rate structure for this rate schedule is a basic service charge, a demand charge, and a seasonally adjusted declining block energy rate with two tiers. The Company proposes to remove the first tier energy charge, modify the remaining energy charge to reflect the average energy cost per kWh, and revise the demand charge to include the implicit demand that was embodied in the first tier energy charge (Miessner direct at page 18). Mr. Miessner argues that this proposed design modification is more consistent with the extra-large general service rate structure and therefore, the Company believes that this modification will smooth the transition between large and extra-large general service when customers change their usage over time. (Id)

**Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

A. No. The result of the company proposed rate design is to increase the demand charge dramatically and leave the average energy charge essentially unchanged with a 1% increase in rates. This gives a dramatic increase in rates to low load factor customers and almost no increase for the high load factor customers as evidenced by the bill impact table that was taken from SFR Schedule H-4.

| kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Monthly Bill under Proposed Rates | Change Amount ($) | Change % |
|---|---|---|---|---|---|---|
| 1,000 | 15% | 109,500 | $ 14,712 | $ 19,049 | $ 4,337 | 29% |
| 1,000 | 30% | 219,000 | $ 23,146 | $ 23,702 | $ 555 | 2% |
| 1,000 | 45% | 328,500 | $ 27,788 | $ 28,354 | $ 566 | 2% |
| 1,000 | 60% | 438,000 | $ 32,430 | $ 33,007 | $ 577 | 2% |
| 1,000 | 75% | 547,500 | $ 37,071 | $ 37,660 | $ 588 | 2% |

In addition, I can find no evidence of the propriety of the Company's argument that the rate design would ease the transition to the rate schedule for extra large general service rate customers, E-35. For a 75% load factor E-32 customer with a demand of 3,000 kW, under the Company's proposed rate structure the customer would have a monthly bill of $111,982 whereas the same customer under E-35 would have a bill of $124,521 or 11% higher than that of the E-32 rate schedule. If the Company really wanted to ease the transition for the E-32 customer, the rate design should be one that increased the rate for this 3,000 kW customer closer to that of the E-35 customer. Instead, the Company put almost all the increase into the demand charge.

**NEW RATE OFFERINGS**

**Q. IS THE COMPANY PROPOSING ANY NEW RATES FOR RESIDENTIAL CUSTOMERS?**

A. Yes. APS is proposing an experimental voluntary peak time rebate demand response program for residential customers (Miessner direct at page 13). The rate will be available for two years but can be extended beyond that time if the program concept proves to be advantageous (Id). Program participation can be capped by APS at its discretion but will not be less than 1,000 customers (Id).

Under the program, the Company can designate up to 18 critical weekdays during the core summer months when the load is either difficult or expensive to serve. Participating customers are notified the prior day and can achieve bill savings of $0.25 per kWh for all kWh reduced from 2 p.m. to 7 p.m. during the critical day. The kWh reduction will be determined by comparing the actual metered usage during those hours with a baseline load that reflects the customer's typical or expected usage during those hours.

The program is similar to the current peak event-pricing program, Critical Peak Pricing – Residential or CPP-RES. As explained by Company witness Miessner many aspects are the same for both programs, including the number of peak event days and hours, the customer notification, and the pricing level for peak event hours (Miessner direct at page 14). However, under CPP-RES, customers receive a monthly discount for all kWh but are charged a higher price during the peak event hours (Id). Thus, under the current program customers save money by avoiding usage during peak event hours, thereby reaping the monthly discount and avoiding high peak event prices to the extent possible, i.e. avoiding a stick (Id). Conversely, under the proposed peak time rebate program customers receive a rebate for the kWh reduced during peak event hours – only a carrot (Id).

**Q. ARE THERE ANY OTHER NEW RATE OFFERINGS?**

A. Yes. APS is proposing Experimental Rate Rider Schedule AG-1, which allows for alternative generation service for extra-large general service customers with average monthly demands of 10 MW or more and are served under Rate Schedules E-34 and E-35. This is an experimental program will be available for three years from the initial date and limited to 200 MW of generation procured under this offering (Miessner direct at page 20). Any power delivered to the APS system on behalf of a customer must be delivered to one or more of the Company's points of delivery for wholesale power (Id). The Company will provide scheduling and, if necessary, load following services for the power – for a fee -- and APS will continue to supply transmission, delivery and revenue cycle services to the customer under the provisions of the customer's current retail rate schedule (Id). The customer must contract for service under this schedule for at least one year and if the customer wishes to return to the standard APS generation service before the contract term, due to a default or other reason, they will be assessed a returning cost based customer charge (Miessner direct at page 21).

The Company is also proposing Rate Rider Schedule IRR that provides interruptible service for extra-large general service customers. This rate offers interruptible service to extra-large general service customers that can interrupt at least 500 kW of load when requested by the Company (Miessner direct at page 20). Under this service, the customer can choose between two curtailment options, two notification options, and a one-year or five-year agreement (Miessner direct at page 22). Mr. Miessner explains that the Customer will receive capacity and energy payments for the interruptible load based on these options (Id). He further explains that the customer may also incur a penalty for failing to curtail when requested (Id). This rate concept was previously filed under a separate matter pending under Docket No. E-01345A-10-0250, but is being included in the instant proceeding with the concurrence of potentially interested parties (Miessner direct at page 19).

**Q. WHAT DO YOU RECOMMEND?**

A. Rate design is a very effective way to induce customers to be conscientious of their energy use and these new programs would complement the Company's efforts to control load through rate design options. RUCO supports the programs and recommends their approval.

## MISCELLANEOUS CHANGES

**Q. PLEASE DISCUSS THE REMAINING CHANGES TO RATES, FEES, CHARGES AND SCHEDULES THAT THE COMPANY PROPOSES.**

A. The Company proposes a series of changes to a variety of rate schedules, riders to rate schedules, and service schedules. These changes generally apply to a certain types of customers, or specific end uses or customer circumstances. APS proposes to modify the following:

- Modify outdoor lighting Rate Schedules E-47 – Dusk to Dawn Lighting Service and E-58 – Street Lighting Service. For both rate schedules equipment may be wither Company or customer owned. The Company proposes to modify the tariffs by adding a trip charge for certain maintenance services. Specifically, APS proposes that when the Company is not the responsible party contracted for the regular maintenance of a lighting system owned by a city, town or other governmental entity, a $100 trip charge per light will be charged when the customer requests a disconnect or reconnect of service in order to accommodate the maintenance activities of the customer or its designee on their lighting equipment. The trip charge will also apply when the customer requests disconnect or reconnect for non-maintenance purposes. In addition, APS proposes that for any lighting system investment of

$25,000 or more, the customer will be required to sign an agreement that limits the Company's financial liability and protects against potential stranded lighting equipment investment;

- For Rate Schedule E-221 – Water Pumping TOU -- the Company is proposing to change the on-peak hours for schedule E221-8T to 11 a.m. to 9 p.m. weekdays to better reflect the Company's hourly on-peak retail load and be consistent with general service time-of-use rates. Currently, the customer can choose an on-peak period of 8 consecutive hours from 9 a.m. to 10 p.m. all days. As a result, the customer could choose an on-peak period of 9 a.m. to 5 p.m., which would incent them to shift load to the 5 p.m. to 7 p.m. time period, which is right in heart of the Company's highest peak load hours in summer months. The Company's proposal will seek to correct this counter-productive price signal. APS also proposes to eliminate the time-of-week option for Rate Schedule E221. The Company reports that this option has low participation, and the time-of-use periods and price signals do not appropriately reflect the Company's peak time periods and costs.

- The Company also proposes to cancel Rate Schedule E-40 -- Agricultural Wind Machine Services. This rate schedule is frozen to new customers and has one customer with very minimal electrical usage. The Company reports that this one customer will be switched to Rate Schedule E32 S, which is more appropriate and cost based;

- The Company also proposes to cancel Rate Schedule Solar-2 – Individual Solar Electric ("Solar-2") for off-grid solar service and cancel Rate Rider Schedule Solar-3 - Solar Power Pilot Program ("Solar-3). The Company reports that Solar-2 has no customers and Solar-3 has two. The company believes that both rates are no longer necessary given the Company's other solar and green power program options;

- Revise Rate Rider Schedule E-56 – Partial Requirements Service – that applies to on-sight distributed generation. The Company proposes to clarify how the "supplemental" and "backup" charges are determined. Currently, the rate offers "supplemental service", the amount of power (kW) and energy (kWh) that the customer typically uses from APS, and "backup service", the additional power and energy that they use when their generator goes down. The rate also offers maintenance service, which replaces backup power and energy when the generator outage occurs during specified time periods and with proper notice to APS. Under the current tariffs, the supplemental power is currently capped at a contracted amount that is specified in an electric supply agreement. The Company proposes that this contracted supplemental power is reset each year, based on the customer's actual metered kW during the summer billing season—specifically, the maximum daily 15-minute metered kW averaged over the billing months May through October. The company argues that this will ensure that the supplemental power is consistent with the customer's actual demand during the summer months when the Company's capacity requirements are most critical. APS is also proposing language to specify that the rates for backup power, which are specified for customers served under "parent" Rate Schedules E-34 and E-32 will be based on the customer's total metered load and determined by the provisions of the parent rate schedules;

- Revise Rate Rider Schedule SC-S – Special Contract Solar – that is applicable for on-site solar distributed generation. The Company wishes to clarify and simplify the tariff language. The Company is also proposing to expand the types of renewable generation that qualify for the rate. Currently, only solar generation technologies can participate in the rate. The Company proposes to allow participation for solar, wind, geothermal, biomass, and biogas renewable generation technologies. Rate Schedule SC-S will also be renamed Rate Rider Schedule E-56 R;

- The Company also proposes to offer a new rate for station-use power for customers with monthly demand below 3 MW. Merchant generators require power for "station use", such as startup power, power draws from inactive inverters, HVAC and lighting loads associated with the generator and supporting facilities and other related power requirements. This rate schedule was originally designed to provide starting power for large gas-fired generators. The proposed Rate Schedule E-36 M will serve merchant generators with a power supply capacity of less than 3 MW. Customers with average monthly billing demands below 100 kW will be billed according to the energy charges in Rate Schedule E-32 XS. All other participating customers will be billed according to the demand and energy charges specified in E-32 L. The unbundled charges for revenue cycle services, such as metering and billing, will be higher than the E-32 amounts consistent with the higher costs to meter this service;

- Revise the green power rider rate schedules to remove a provision for the exemption from adjustor schedule RES. Currently the green power rates exempt the customer from paying the charges for the renewable energy standard, the proposed adjustment Schedule REAC-1 (formerly RES), for any kWh purchased under the green power schedules GPS-1, GPS-2 and GPS-3. APS is seeking to eliminate this exemption. APS believes that the exemption may potentially allow some customers to avoid paying their fair share of the renewable energy standard costs and, consequentially, result in the renewable programs being underfunded and ultimately shift costs to other customers. The Company argues that on the surface, this exemption appears to have merit. The defense for the exemption has been that customers should not pay a renewable energy standard adjustment fee on green power that is already priced at a premium rate, which reflects the above market cost of renewable power—it is akin to paying twice for the same green power (proponents argue). The Company states, however, that it is important to consider that the renewable energy standard funding is mandatory for all customers, while green power is a voluntary purchase driven by the customer's corporate policies, third-party environmental certifications, or personal preferences. The Company believes that all customers should be required to pay their fair share of the mandatory RES requirements, regardless of any voluntary purchases of green power, which do not count toward those requirements.

- Rate Schedule E-30 is applicable for general service customers with constant demand and energy requirements that are difficult or impractical to meter. The Company proposes to is modifying this rate to require that the determination of the fixed monthly billed energy usage will be derived from the manufacturer's nameplate rating of the equipment, and that the customer's electrical service must be supplied at one site through one point of delivery as specified by an individual customer contract (Miessner direct at page 19).

- Revise Service Schedule 1, terms and conditions for electrical service, to reflect various proposed changes in service and credit policies and to clarify certain provisions to reflect current Company policies; and

- Propose a new Service Schedule 9 to provide incentives for commercial and industrial development in the APS service territory.

**Q. WHAT DO YOU RECOMMEND?**

A. The Company has proposed a whole series of changes to a variety of rate schedules, riders to rate schedules, and service schedules. These changes generally apply to a certain types of customers, or specific end uses or customer circumstances and are considered housekeeping changes that will result in more accurate billing or fine-tune the applicability of a service class while having little or no impact on other customers. RUCO supports the modifications.

**PROPOSAL TO MODIFY TRANSMISSION COST ADJUSTMENT**

**Q. PLEASE DISCUSS HOW THE COMPANY PROPOSES TO CHANGE HOW TRANSMISSION COSTS ARE COLLECTED?**

A. Currently, the Company recovers the revenue requirements for transmission services from two charges: an amount built into base rates and a transmission cost adjustor rate, the Transmission Cost Adjustor ("TCA"). The TCA provides for recovery of the regulated transmission revenue requirements are not recovered through base rates. The total transmission revenue requirement is established annually by the Federal Energy Regulatory Commission. APS argues that since the total revenue requirement and rate design are established in the FERC formula rate process, in which the Commission Staff is an active participant, and any additional action by the Commission is not necessary. The Company notes that the change in revenue recovery will not increase ratepayers overall bills.

**Q. WHAT DO YOU RECOMMEND?**

A. Generally RUCO believes that adjustor mechanisms are unwarranted unless the costs revered through the adjustor are highly volatile and beyond the Company's ability to control. RUCO does not believe that the Company has shown that transmission costs to be highly volatile or beyond its control. In addition, while RUCO recognizes that Commission Staff is a party to a FERC proceeding, this is not the same as have full regulatory authority when issues come before the

Arizona Corporation Commission. This is consistent with commission policy where the TCA is to be adjusted upon a filing with the Commission and a review of that report by ACC Staff. On both these grounds, RUCO opposes the change.

**PRESENTATION OF CHARGES ON RETAIL BILLS**

**Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO REDESIGN THE CUSTOMER BILL**

A. As described in detail by Company witness Miessner, as part of the effort to promote direct access from an alternative provider APS has unbundled rates with rates for specific services, such as billing, metering, system benefits, distribution delivery, transmission, and generation capacity and energy (See Miessner direct at pages 33-35). The rate schedules also include the bundled charges, which are the summation of all the individual unbundled charges for similar billing determinants (Id). This makes for a fairly long and complicated bill that can sometimes cause customers complaints (Id). To address this issue, the Company proposes to simplify the customer's bill by providing the bundled charges and related information but the Company can be provided to a customers on an opt-in basis if they so desire (Id).

**Q. WHAT DO YOU RECOMMEND?**

A. RUCO supports any efforts that will result in bill simplification and it is my experience that customers are generally wary of adjustor mechanisms and surcharges. Given the revision to the bill would not hamper any effort to resurrect retail competition in Arizona RUCO has no problem with the general concept that the Company proposes.

That said, however, delineating the DSM and RES adjusters are entirely different issues. These charges have nothing to do with bundled or unbundled services relating to retail competition. They are charges for programs ordered by the Commission and they are not inherent costs of providing electrical service. It is RUCO's position that there should be full transparency of the cost of these programs and these charges should be delineated so that customers can see what these policy decisions cost them on a month-to-month basis.

For this same reason, RUCO opposes the proposal by Southwest Energy Efficiency Project witness Jeffrey Schlegel to move $70 million of DSM expenditures into base rates (Schlegel direct at page 7). Mr. Schlegel notes that the Company already has a $10 million expense level in bases rates and expects to spend $78 million for 2012 (Id). Mr. Schlegel argues that in order to provide for adequate treatment for this central energy resource, it is critical that $70 million of energy efficiency programs be expensed through base rates (Id). Mr. Schlegel does not explain why energy efficiency needs adequate treatment or how it gets adequate treatment by having the cost of the programs recovered in base rates as opposed to recovery through the DSMAC. Mr. Schlegel's proposal is also supported by the witness for Western Resource Advocates Mr. David Berry (see Berry direct at page 17) but he does not even provide an explanation why the base rate recovery should be increased.

Given that the cost recovery of the energy efficiency programs is the same through base rates or the Demand Side Management Adjustment Clause ("DSMAC"), the only reason that I can think of is to mask how much money is being spent on energy efficiency. If the value of a product or service cannot stand up to scrutiny in the light of day, it probably means that it should have never been considered for use in the first place. Shrinking from full disclosure is wrong as it not only tries to hide a cost element from ratepayers but it also does a disservice to energy efficiency efforts. Since Mr. Schlegel testifies that energy efficiency is the lowest cost energy resource (see Schlegel direct at pages 6-7), I cannot imagine why he would shrink from full disclosure position. RUCO supports full disclosure and opposes any shifting of funds from the DSMAC to base rates.

**Q. DOES THAT CONCLUDE YOUR TESITMONY ON RATE DESIGN?**

A. Yes it does.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND RUCO PROPOSED RATES
TEST YEAR ENDING DECEMBER 31, 2010 ADJUSTED

| | | Base Revenues in the Test Year (a) | | Proposed Increase (b) | | |
|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | |
| Line No. | Customer Classification | Present Rates [1, 2] ($000) | Proposed Rates [2] ($000) | Amount ($000) (B) - (A) | % (C) / (A) | Line No. |
| 1. | Residential | $ 1,472,110 | $ 1,472,110<br>$ - | $ - | 0.00% | 1. |
| 2. | General Service | 1,344,730 | 1,344,730<br>- | - | 0.00% | 2. |
| 3. | Irrigation/Water Pumping | 26,717 | 26,717<br>- | - | 0.00% | 3. |
| 4. | Outdoor Lighting | 21,020 | 21,020<br>- | - | 0.00% | 4. |
| 5. | Dusk to Dawn Lighting Service | 8,460 | 8,460 | - | 0.00% | 5. |
| 6. | Total Sales to Ultimate Retail Customers | $ 2,873,037 | $ 2,873,037 | $ - | 0.00% | 6. |

Notes:
1) Base Revenues under Present Rates reflect adjusted Test Year revenues including applicable pro forma adjustments.
2) Present and Proposed Rates base revenues include transmission. Costs based on OATT rates effective during Test Year.

Supporting Schedules:
(a) RUCO H-2

Recap Schedules:
(b) A-1

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | RUCO Proposed Revenue | | | Increase - Base Rates | | |
| Line No. | Customer Classification and Current Rate Designation | Average Number of Customers | Adjusted MWh Sales | Average Annual kWh Usage per Customer | Base Revenues under Present Rates[1] ($000) | Proposed Rate Designation | Base Revenues ($000) | Transmission Revenue [7] ($000) | Total Revenue ($000) | Amount ($000) | % | Line No. |
| | | | | [(C) x 1000] / (B) | | | | | | (I) - (E) | (J) / (E) | |
| 1. | Residential | | | | | | | | | | | 1. |
| 2. | E-12 | 449,101 | 3,698,573 | 8,236 | 464,916 | E-12 | 464,916 | - | 464,916 | - | 0.00% | 2. |
| 3. | ET-1 | 278,353 | 4,136,790 | 14,862 | 462,962 | ET-1 | 462,962 | - | 462,962 | - | 0.00% | 3. |
| 4. | ET-2 | 114,450 | 1,739,717 | 15,201 | 250,367 | ET-2 | 250,367 | - | 250,367 | - | 0.00% | 4. |
| 5. | ECT-2 | 38,017 | 1,364,662 | 35,896 | 104,598 | ECT-2 | 104,598 | - | 104,598 | - | 0.00% | 5. |
| 6. | ECT-1R | 47,380 | 1,385,780 | 29,248 | 120,641 | ECT-1R | 120,641 | - | 120,641 | - | 0.00% | 6. |
| 7. | ET-SP | 108 | 2,301 | 21,306 | 221 | ET-SP | 221 | - | 221 | - | 0.00% | 7. |
| 8. | E-12 Low income | 36,296 | 328,089 | 9,039 | 29,058 | E-12 Low income | 29,058 | - | 29,058 | - | 0.00% | 8. |
| 9. | ET-1 low income | 15,267 | 207,243 | 13,575 | 18,681 | ET-1 low income | 18,681 | - | 18,681 | - | 0.00% | 9. |
| 10. | ET-2 low income | 8,588 | 179,769 | 20,933 | 16,035 | ET-2 low income | 16,035 | - | 16,035 | - | 0.00% | 10. |
| 11. | ECT-2 low income | 1,431 | 36,200 | 25,297 | 2,993 | ECT-2 low income | 2,993 | - | 2,993 | - | 0.00% | 11. |
| 12. | ECT-1R Low income | 998 | 19,159 | 19,197 | 1,639 | ECT-1R Low income | 1,639 | - | 1,639 | - | 0.00% | 12. |
| 13. | Total Residential | 989,989 | 13,098,283 | 13,231 | 1,472,110 | Total Residential | 1,472,110 | - | 1,472,110 | - | 0.00% | 13. |
| 14. | | | | | | | | | | | | 14. |
| 15. | General Service | | | | | | | | | | | 15. |
| 16. | E-20 | 328 | 36,664 | 111,780 | 3,891 | E-20 | 3,891 | - | 3,891 | - | 0.00% | 16. |
| 17. | E-30 | 4,644 | 6,349 | 1,367 | 1,407 | E-30 | 1,407 | - | 1,407 | - | 0.00% | 17. |
| 18. | E-40 | 1 | - | - | 1 | See note 9 | | - | | | | 18. |
| 19. | E-32 XS | 82,396 | 1,418,941 | 17,221 | 199,391 | E-32 XS | 199,391 | - | 199,391 | - | 0.00% | 19. |
| 20. | E-32 S | 29,411 | 2,551,983 | 86,770 | 290,406 | E-32 S | 290,406 | - | 290,406 | - | 0.00% | 20. |
| 21. | E-32 M | 4,425 | 3,279,542 | 741,139 | 317,810 | E-32 M | 317,810 | - | 317,810 | (1) | 0.00% | 21. |
| 22. | E-32 L | 1,035 | 3,647,139 | 3,523,806 | 304,349 | E-32 L | 304,349 | - | 304,349 | - | 0.00% | 22. |
| 23. | E-32 TOU XS | 78 | 4,609 | 59,090 | 633 | E-32 TOU XS | 633 | - | 633 | - | 0.00% | 23. |
| 24. | E-32 TOU S | 219 | 41,567 | 189,804 | 4,461 | E-32 TOU S | 4,461 | - | 4,461 | - | 0.00% | 24. |
| 25. | E-32 TOU M | 73 | 69,937 | 958,041 | 6,396 | E-32 TOU M | 6,396 | - | 6,396 | - | 0.00% | 25. |
| 26. | E-32 TOU L | 47 | 295,614 | 6,289,660 | 22,961 | E-32 TOU L | 22,961 | - | 22,961 | - | 0.00% | 26. |
| 27. | E-34 | 36 | 1,086,047 | 30,167,972 | 80,761 | E-34 | 80,761 | - | 80,761 | - | 0.00% | 27. |
| 28. | E-35 | 29 | 1,673,369 | 57,702,379 | 112,262 | E-35 | 112,262 | - | 112,262 | - | 0.00% | 28. |
| 29. | Total General Service | 122,722 | 14,111,761 | 114,990 | 1,344,730 | Total General Service | 1,344,730 | - | 1,344,728 | (1) | 0.00% | 29. |
| 30. | | | | | | | | | | | | 30. |
| 31. | Irrigation and Water Pumping | 1,450 | 313,308 | 216,074 | 26,717 | Irrigation and Water Pumping | 26,717 | - | 26,717 | - | 0.00% | 31. |
| 32. | | | | | | | | | | | | 32. |
| 33. | Outdoor Lighting | | | | | | | | | | | 33. |
| 34. | E-58 | 624 | 33,212 | 53,224 | 10,112 | E-58 | 10,112 | - | 10,112 | - | 0.00% | 34. |
| 35. | E-59 | 293 | 93,502 | 319,119 | 9,715 | E-59 | 9,715 | - | 9,715 | - | 0.00% | 35. |
| 36. | Contract 12 | 41 | 11,496 | 280,390 | 1,014 | Contract 12 | 1,014 | - | 1,014 | - | 0.00% | 36. |
| 37. | E-67 | 181 | 3,432 | 18,961 | 179 | E-67 | 179 | - | 179 | - | 0.00% | 37. |
| 38. | Total Outdoor Lighting | 1,139 | 141,642 | 124,356 | 21,020 | Total Outdoor Lighting | 21,020 | - | 21,020 | - | 0.00% | 38. |
| 39. | | | | | | | | | | | | 39. |
| 40. | Dusk to Dawn Lighting | See Note 5 | 24,613 | See Note 5 | 8,460 | Dusk to Dawn Lighting | 8,460 | - | 8,460 | - | 0.00% | 40. |
| 41. | | | | | | | | | | | | 41. |
| 42. | Total Sales to Ultimate Retail Customers | 1,115,300 | 27,689,607 See Note 10 | 24,827 | 2,873,037 | | 2,873,037 | - | 2,873,035 | (1) | 0.00% | 42. |

Notes:
1) Base Revenues under Present Rates reflect adjusted test year revenues based on rates established in Decision No. 71448.
2) Share the Light Rate Schedules are included in Rate Schedule E-58.
3) Rider rate schedules are included in the "Parent" rate schedules listed on schedule H-2 as applicable.
Riders include: E-3, E-4, CPP-RES, CMPW-01, E-53, E-54, RSSP, PPR, CPP-GS, Solar-2, Solar-3, GPS-1, GPS-2, GPS-3, EPR-2, EPR-6, E-56, and SC-S.
4) Rate Schedule E-36 is not included as prices are market-related.
5) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.
7) Transmission revenues based on OATT charges effective during test year.
8) Rate Schedules GS Schools M, GS-Schools L have no revenue or customers.
9) Rate E-40 proposed revenue is reflected in E-32 M
10) Excludes 144,149 MWh of revenue credit customers, total sales with revenue credit customers = 27,833,756 MWh

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2010, ADJUSTED

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | RUCO Proposed Revenue | | | Increase -Base Rates | | |
| Line No. | Customer Classification and Current Rate Designation | Average Number of Customers | Adjusted MWh Sales | Average Annual kWh Usage per Customer | Base Revenues under Present Rates[1] ($000) | Proposed Rate Designation | Base Revenues ($000) | Transmission Revenue[7] ($000) | Total Revenue ($000) | Amount ($000) | % | Line No. |
| | | | | [(C) x 1000] / (B) | | | | | | (I) - (E) | (J) / (E) | |

Supporting Schedules:
N/A

Recap Schedules:
(a) H-1

# ARIZONA PUBLIC SERVICE COMPANY
## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND RUCO PROPOSED RATES
## TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 1. | E-3 | Residential Energy | Rate | Sum & Win | For Bills 0-400 kWh | 40% | disc. | For Bills 0-400 kWh | 25% | disc. | -15% | disc. | 1. |
| 2. | | Support Program | | | For Bills 401-800 kWh | 26% | disc. | For Bills 401-800 kWh | 25% | disc. | -1% | disc. | 2. |
| 3. | | | | | For Bills 801-1200 kWh | 14% | disc. | For Bills 801-1200 kWh | $ 18.00 | disc. | depends on usage | disc. | 3. |
| 4. | | | | | For Bills 1201 kWh and above | $ 13.00 | disc. | For Bills 1201 kWh and above | $ 18.00 | disc. | $ 5.00 | disc. | 4. |
| 5. | | | | | | | | | | | | | 5. |
| 6. | E-4 | Medical Care | Rate | Sum & Win | For Bills 0-800 kWh | 40% | disc. | For Bills 0-800 kWh | 25% | disc. | -15% | disc. | 6. |
| 7. | | Equipment | | | For Bills 801-1400 kWh | 26% | disc. | For Bills 801-1400 kWh | $ 36.00 | disc. | depends on usage | disc. | 7. |
| 8. | | Support Program | | | For Bills 1401-2000 kWh | 14% | disc. | For Bills 1401-2000 kWh | $ 36.00 | disc. | depends on usage | disc. | 8. |
| 9. | | | | | For Bills 2001 kWh and above | $ 26.00 | disc. | For Bills 2001 kWh and above | $ 36.00 | disc. | $ 10.00 | disc. | 9. |
| 10. | | | | | | | | | | | | | 10. |
| 11. | E-12 | Residential Service | Rate | Summer | Basic Service Charge | $ 0.285 | /day | Basic Service Charge | $ 0.314 | /day | $ 0.029 | /day | 11. |
| 12. | | | | | First 400 kWh | 0.09671 | /kWh | First 400 kWh | 0.09671 | /kWh | - | /kWh | 12. |
| 13. | | | | | Next 400 kWh | 0.13739 | /kWh | Next 400 kWh | 0.12828 | /kWh | (0.00911) | /kWh | 13. |
| 14. | | | | | Next 2200 kWh | 0.16281 | /kWh | Next 2200 kWh | 0.16281 | /kWh | - | /kWh | 14. |
| 15. | | | | | All additional kWh | 0.17358 | | All additional kWh | 0.18226 | /kWh | 0.00868 | /kWh | 15. |
| 16. | | | | | | | | | | | | | 16. |
| 17. | | | | Winter | Basic Service Charge | $ 0.285 | /day | Basic Service Charge | $ 0.314 | /day | $ 0.029 | /day | 17. |
| 18. | | | | | All kWh | 0.09397 | /kWh | All kWh | 0.09397 | /kWh | - | /kWh | 18. |
| 19. | | | | | | | | | | | | | 19. |
| 20. | | | Minimum | Sum & Win | Basic Service Charge | $ 0.285 | /day | Basic Service Charge | $ 0.314 | /day | $ 0.029 | /day | 20. |
| 21. | | | | | | | | | | | | | 21. |
| 22. | ET-1 | Residential Service | Rate | Summer | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 22. |
| 23. | | Time of Use | | | All On-Peak kWh | 0.17866 | /kWh | All On-Peak kWh | 0.18759 | /kWh | 0.00893 | /kWh | 23. |
| 24. | | | | | All Off-Peak kWh | 0.05774 | /kWh | All Off-Peak kWh | 0.05037 | /kWh | (0.00737) | /kWh | 24. |
| 25. | | | | | | | | | | | | | 25. |
| 26. | | | | Winter | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 26. |
| 27. | | | | | All On-Peak kWh | 0.14515 | /kWh | All On-Peak kWh | 0.15241 | /kWh | 0.00726 | /kWh | 27. |
| 28. | | | | | All Off-Peak kWh | 0.05565 | /kWh | All Off-Peak kWh | 0.04893 | /kWh | (0.00672) | /kWh | 28. |
| 29. | | | | | | | | | | | | | 29. |
| 30. | | | Minimum | Sum & Win | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 30. |
| 31. | | | | | | | | | | | | | 31. |
| 32. | ET-2 | Residential Service | Rate | Summer | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 32. |
| 33. | | Time of Use | | | All On-Peak kWh | 0.24445 | /kWh | All On-Peak kWh | 0.25667 | /kWh | 0.01222 | /kWh | 33. |
| 34. | | | | | All Off-Peak kWh | 0.06126 | /kWh | All Off-Peak kWh | 0.05609 | /kWh | (0.00517) | /kWh | 34. |
| 35. | | | | | | | | | | | | | 35. |
| 36. | | | | Winter | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.05560 | /day | 36. |
| 37. | | | | | All On-Peak kWh | 0.19825 | /kWh | All On-Peak kWh | 0.20816 | /kWh | 0.00991 | /kWh | 37. |
| 38. | | | | | All Off-Peak kWh | 0.06124 | /kWh | All Off-Peak kWh | 0.05608 | /kWh | (0.00516) | /kWh | 38. |
| 39. | | | | | | | | | | | | | 39. |
| 40. | | | Minimum | Sum & Win | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.05560 | /day | 40. |
| 41. | | | | | | | | | | | | | 41. |
| 42. | ECT-1R | Residential Service | Rate | Summer | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 42. |
| 43. | | Time of Use with | | | All On-Peak kW | 13.372 | /kW | All On-Peak kW | 14.041 | /kW | $ 0.669 | /kW | 43. |
| 44. | | Demand Charge | | | All On-Peak kWh | 0.07434 | /kWh | All On-Peak kWh | 0.07806 | /kWh | $ 0.00372 | /kWh | 44. |
| 45. | | | | | All Off-Peak kWh | 0.04159 | /kWh | All Off-Peak kWh | 0.03494 | /kWh | $ (0.00665) | /kWh | 45. |
| 46. | | | | | | | | | | | | | 46. |
| 47. | | | | Winter | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 47. |
| 48. | | | | | All On-Peak kW | 9.189 | /kW | All On-Peak kW | 9.648 | /kW | $ 0.459 | /kW | 48. |
| 49. | | | | | All On-Peak kWh | 0.05609 | /kWh | All On-Peak kWh | 0.05889 | /kWh | $ 0.00280 | /kWh | 49. |
| 50. | | | | | All Off-Peak kWh | 0.03976 | /kWh | All Off-Peak kWh | 0.03340 | /kWh | $ (0.00636) | /kWh | 50. |
| 51. | | | | | | | | | | | | | 51. |
| 52. | | | Minimum | Sum & Win | Minimum | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 52. |
| 53. | | | | | | | | | | | | | 53. |
| 54. | ECT-2 | Residential Service | Rate | Summer | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 54. |
| 55. | | Time of Use with | | | All On-Peak kW | 13.404 | /kW | All On-Peak kW | 14.074 | /kW | 0.671 | /kW | 55. |
| 56. | | Demand Charge | | | All On-Peak kWh | 0.08845 | /kWh | All On-Peak kWh | 0.09287 | /kWh | 0.00442 | /kWh | 56. |
| 57. | | | | | All Off-Peak kWh | 0.04363 | /kWh | All Off-Peak kWh | 0.03695 | /kWh | (0.00468) | /kWh | 57. |
| 58. | | | | | | | | | | | | | 58. |
| 59. | | | | Winter | Basic Service Charge | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | 0.056 | /day | 59. |
| 60. | | | | | All On-Peak kW | 9.203 | /kW | All On-Peak kW | 9.663 | /kW | 0.460 | /kW | 60. |
| 61. | | | | | All On-Peak kWh | 0.05815 | /kWh | All On-Peak kWh | 0.06106 | /kWh | 0.00291 | /kWh | 61. |
| 62. | | | | | All Off-Peak kWh | 0.04273 | /kWh | All Off-Peak kWh | 0.03815 | /kWh | (0.00458) | /kWh | 62. |
| 63. | | | | | | | | | | | | | 63. |
| 64. | | | Minimum | Sum & Win | Minimum | $ 0.556 | /day | Basic Service Charge | $ 0.612 | /day | 0.056 | /day | 64. |

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 1/01/2010.

Recap Schedules:
N/A

## ARIZONA PUBLIC SERVICE COMPANY

### CHANGES IN REPRESENTATIVE RATE SCHEDULES
### COMPARISON OF PRESENT AND RUCO PROPOSED RATES
### TEST YEAR ENDING DECEMBER 31, 2010

| Line No. | (A) Rate Schedule | (B) Description | (C) Billing Designation | (D) Season | (E) Present Rates Block | (F) Present Rates Rates | (G) | (H) Proposed Rates Block | (I) Proposed Rates Rates | (J) | (K) Change (I) - (F) | (L) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 65. | | | | | | | | | | | | | 65. |
| 66. | ET-SP | Residential Service | Rate | Super Peak | Basic Service Charge | $ 0.556 | | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 66. |
| 67. | | | | Summer | All Super-Peak kWh | 0.49445 | | All Super-Peak kWh | 0.46282 | /kWh | (0.03163) | /kWh | 67. |
| 68. | | Time of Use | | | All On-Peak kWh | 0.24445 | | All On-Peak kWh | 0.25667 | /kWh | 0.01222 | /kWh | 68. |
| 69. | | | | | All Off-Peak kWh | 0.05254 | | All Off-Peak kWh | 0.05188 | /kWh | (0.00066) | /kWh | 69. |
| 70. | | | | | | | | | | | | | 70. |
| 71. | | | | Summer | Basic Service Charge | $ 0.556 | | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 71. |
| 72. | | | | | All On-Peak kWh | 0.24445 | | All On-Peak kWh | 0.25667 | /kWh | 0.01222 | /kWh | 72. |
| 73. | | | | | All Off-Peak kWh | 0.05254 | | All Off-Peak kWh | 0.05188 | /kWh | (0.00066) | /kWh | 73. |
| 74. | | | | | | | | | | | | | 74. |
| 75. | | | | Winter | Basic Service Charge | $ 0.556 | | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 75. |
| 76. | | | | | All On-Peak kWh | 0.19825 | | All On-Peak kWh | 0.20816 | /kWh | 0.00991 | /kWh | 76. |
| 77. | | | | | All Off-Peak kWh | 0.05253 | | All Off-Peak kWh | 0.05187 | /kWh | (0.00066) | /kWh | 77. |
| 78. | | | | Sup. Pk. Sum, | | | | | | | | | 78. |
| 79. | | | Minimum | Sum & Win | Basic Service Charge | $ 0.556 | | Basic Service Charge | $ 0.612 | /day | $ 0.056 | /day | 79. |
| 80. | | | | | | | | | | | | | 80. |
| 81. | E-12 L | Residential Service | Rate | Summer | Basic Service Charge | $ 0.253 | /day | Basic Service Charge | $ 0.278 | /day | $ 0.025 | /day | 81. |
| 82. | | | | | First 400 kWh | 0.08570 | /kWh | First 400 kWh | 0.08570 | /kWh | - | /kWh | 82. |
| 83. | | | | | Next 400 kWh | 0.12175 | /kWh | Next 400 kWh | 0.10982 | /kWh | (0.01193) | /kWh | 83. |
| 84. | | | | | All additional kWh | 0.14427 | /kWh | Next 2200 | 0.14427 | /kWh | - | /kWh | 84. |
| 85. | | | | | | | | All Additional | $ 0.15148 | | | | 85. |
| 86. | | | | | | | | | | | | | |
| 87. | | | | Winter | Basic Service Charge | $ 0.253 | /day | Basic Service Charge | $ 0.278 | /day | $ 0.025 | /day | 87. |
| 88. | | | | | All kWh | 0.08327 | /kWh | All kWh | 0.07511 | /kWh | (0.00816) | /kWh | 88. |
| 89. | | | | | | | | | | | | | 89. |
| 90. | | | Minimum | Sum & Win | Basic Service Charge | $ 0.253 | /day | Basic Service Charge | $ 0.278 | /day | $ 0.025 | /day | 90. |
| 91. | | | | | | | | | | | | | 91. |
| 92. | ET-1 L | Residential Service | Rate | Summer | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 92. |
| 93. | | Time of Use | | | All On-Peak kWh | 0.15810 | /kWh | All On-Peak kWh | 0.16601 | /kWh | 0.00791 | /kWh | 93. |
| 94. | | | | | All Off-Peak kWh | 0.05110 | /kWh | All Off-Peak kWh | 0.03884 | /kWh | (0.01226) | /kWh | 94. |
| 95. | | | | | | | | | | | | | 95. |
| 96. | | | | Winter | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 96. |
| 97. | | | | | All On-Peak kWh | 0.12845 | /kWh | All On-Peak kWh | 0.13487 | /kWh | 0.00642 | /kWh | 97. |
| 98. | | | | | All Off-Peak kWh | 0.04925 | /kWh | All Off-Peak kWh | 0.03743 | /kWh | (0.01182) | /kWh | 98. |
| 99. | | | | | | | | | | | | | 99. |
| 100. | | | Minimum | Sum & Win | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 100. |
| 101. | | | | | | | | | | | | | 101. |
| 102. | ET-2 L | Residential Service | Rate | Summer | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 102. |
| 103. | | Time of Use | | | All On-Peak kWh | 0.21601 | /kWh | All On-Peak kWh | 0.22681 | /kWh | 0.01080 | /kWh | 103. |
| 104. | | | | | All Off-Peak kWh | 0.05413 | /kWh | All Off-Peak kWh | 0.04566 | /kWh | (0.00847) | /kWh | 104. |
| 105. | | | | | | | | | | | | | 105. |
| 106. | | | | Winter | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 106. |
| 107. | | | | | All On-Peak kWh | 0.17519 | /kWh | All On-Peak kWh | 0.18395 | /kWh | 0.00876 | /kWh | 107. |
| 108. | | | | | All Off-Peak kWh | 0.05412 | /kWh | All Off-Peak kWh | 0.04565 | /kWh | (0.00847) | /kWh | 108. |
| 109. | | | | | | | | | | | | | 109. |
| 110. | | | Minimum | Sum & Win | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 110. |
| 111. | | | | | | | | | | | | | 111. |
| 112. | ECT-1R L | Residential Service | Rate | Summer | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 112. |
| 113. | | Time of Use with | | | All On-Peak kW | 11.860 | /kW | All On-Peak kW | 12.453 | /kW | 0.593 | /kW | 113. |
| 114. | | Demand Charge | | | All On-Peak kWh | 0.06593 | /kWh | All On-Peak kWh | 0.06923 | /kWh | 0.00330 | /kWh | 114. |
| 115. | | | | | All Off-Peak kWh | 0.03689 | /kWh | All Off-Peak kWh | 0.02464 | /kWh | (0.01225) | /kWh | 115. |
| 116. | | | | | | | | | - | | | | 116. |
| 117. | | | | Winter | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | 0.542 | /day | 0.04930 | /day | 117. |
| 118. | | | | | All On-Peak kW | 8.150 | /kW | All On-Peak kW | 8.56 | /kW | 0.40750 | /kW | 118. |
| 119. | | | | | All On-Peak kWh | 0.04975 | /kWh | All On-Peak kWh | 0.0522 | /kWh | 0.00249 | /kWh | 119. |
| 120. | | | | | All Off-Peak kWh | 0.03526 | /kWh | All Off-Peak kWh | 0.02355 | /kWh | (0.01171) | /kWh | 120. |
| 121. | | | | | | | | | | | | | 121. |
| 122. | | | Minimum | Sum & Win | Minimum | $ 0.493 | /day | Basic Service Charge | 0.542 | /day | 0.04930 | /day | 122. |
| 123. | | | | | | | | | | | | | 123. |
| 124. | ECT-2 L | Residential Service | Rate | Summer | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 124. |
| 125. | | Time of Use with | | | All On-Peak kW | 11.870 | /kW | All On-Peak kW | 12.464 | /kW | 0.594 | /kW | 125. |
| 126. | | Demand Charge | | | All On-Peak kWh | 0.07833 | /kWh | All On-Peak kWh | 0.08225 | /kWh | 0.00392 | /kWh | 126. |
| 127. | | | | | All Off-Peak kWh | 0.03864 | /kWh | All Off-Peak kWh | 0.02956 | /kWh | (0.00908) | /kWh | 127. |
| 128. | | | | | | | | | - | | | | 128. |
| 129. | | | | Winter | Basic Service Charge | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 129. |
| 130. | | | | | All On-Peak kW | 8.150 | /kW | All On-Peak kW | 8.878 | /kW | 0.728 | /kW | 130. |
| 131. | | | | | All On-Peak kWh | 0.05150 | /kWh | All On-Peak kWh | 0.04993 | /kWh | (0.00157) | /kWh | 131. |
| 132. | | | | | All Off-Peak kWh | 0.03784 | /kWh | All Off-Peak kWh | 0.02895 | /kWh | (0.00889) | /kWh | 132. |
| 133. | | | | | | | | | | | | | 133. |
| 134. | | | Minimum | Sum & Win | Minimum | $ 0.493 | /day | Basic Service Charge | $ 0.542 | /day | $ 0.049 | /day | 134. |

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 1/01/2010.

# ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND RUCO PROPOSED RATES
### TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 135 | | | | | | | | | | | | | 135. |
| 136. | CPP-RES | Residential Service | Rate | Summer | Critical Peak Price | $ 0.40000 | /kWh | Critical Peak Price | $ 0.250000 | /kWh | $ (0.150000) | /kWh | 136. |
| 137 | | Critical Peak Pricing | | | Energy Discount | $ (0.018910) | /kWh | Energy Discount | $ (0.012143) | /kWh | $ 0.006767 | /kWh | 137. |
| 138. | | | | | | | | | | | | | 138. |
| 139. | PTR-RES | Residential Service | Rate | Summer | PROPOSE NEW SCHEDULE | | | Energy Discount | $ 0.250000 | /kWh | $ 0.250000 | /kWh | 139. |
| 140. | | Peak Time Rebate | | | | | | | | | | | 140. |
| 141. | | | | | | | | | | | | | 141. |
| 142. | E-20 | General Service | Rate | Summer | Basic Service Charge | $ 1.065 | /day | Basic Service Charge | $ 1.172 | /day | $ 0.107 | /day | 142. |
| 143. | | Time of Use for | | | All On-Peak kW | 2.391 | /kW | All On-Peak kW | 2.511 | /kW | 0.120 | /kW | 143. |
| 144. | | Religious Houses of | | | Excess Off-Peak kW | 1.196 | /kW | Excess Off-Peak kW | 1.256 | /kW | 0.05980 | /kWh | 144. |
| 145. | | Worship | | | All On-Peak kWh | 0.14380 | /kWh | All On-Peak kWh | 0.15099 | /kWh | 0.00719 | /kWh | 145. |
| 146. | | | | | All Off-Peak kWh | 0.06945 | /kWh | All Off-Peak kWh | 0.06431 | /kWh | (0.00514) | /kWh | 146. |
| 147 | | | | | | | | | | | | | 147. |
| 148. | | | | Winter | Basic Service Charge | $ 1.065 | /day | Basic Service Charge | $ 1.172 | /day | $ 0.1065 | /day | 148. |
| 149. | | | | | All On-Peak kW | 2.156 | /kW | All On-Peak kW | 2.264 | /kW | 0.108 | /kW | 149. |
| 150. | | | | | Excess Off-Peak kW | 1.078 | /kW | Excess Off-Peak kW | 1.132 | /kW | 0.05390 | /kWh | 150. |
| 151 | | | | | All On-Peak kWh | 0.12644 | /kWh | All On-Peak kWh | 0.13276 | /kWh | 0.00632 | /kWh | 151. |
| 152. | | | | | All Off-Peak kWh | 0.06226 | /kWh | All Off-Peak kWh | 0.05765 | /kWh | (0.00461) | /kWh | 152. |
| 153. | | | | | | | | | | | | | 153. |
| 154. | | | Minimum | Sum & Win | Basic Service Charge | $ 1.065 | /day | Basic Service Charge | $ 1.172 | /day | 0.10650 | /day | 154. |
| 155. | | | | | Demand Charge | 1.951 | /kW | Demand Charge | 1.951 | /kW | - | /kW | 155. |
| 156. | | | | | | | | | | | | | 156. |
| 157. | E-30 | Extra Small General | Rate | Summer | Basic Service Charge | $ 0.311 | /day | Basic Service Charge | $ 0.342 | /day | $ 0.031 | /day | 157. |
| 158. | | Service Unmetered | | | All kWh | 0.14447 | /kWh | All kWh | 0.15169 | /kWh | 0.00722 | /kWh | 158. |
| 159. | | | | | | | | | | | | | 159. |
| 160. | | | | Winter | Basic Service Charge | $ 0.311 | /day | Basic Service Charge | $ 0.342 | /day | $ 0.031 | /day | 160. |
| 161. | | | | | All kWh | 0.12967 | /kWh | All kWh | 0.10438 | /kWh | (0.02529) | /kWh | 161. |
| 162. | | | | | | | | | | | | | 162. |
| 163. | E-32 XS | General Service | Rate | Summer | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 163. |
| 164. | | 20 kW or Less | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 164. |
| 165. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 165. |
| 166. | | | | | First 5,000 kWh: Secondary | 0.13261 | /kWh | First 5,000 kWh: Secondary | 0.13261 | /kWh | - | /kWh | 166. |
| 167. | | | | | All remaining kWh: Secondary | 0.07251 | /kWh | All remaining kWh: Secondary | 0.07251 | /kWh | - | /kWh | 167. |
| 168. | | | | | First 5,000 kWh: Primary | 0.12939 | /kWh | First 5,000 kWh: Primary | 0.12939 | /kWh | - | /kWh | 168. |
| 169. | | | | | All remaining kWh: Primary | 0.06929 | /kWh | All remaining kWh: Primary | 0.06929 | /kWh | - | /kWh | 169. |
| 170. | | | | | | | | | | | | | 170. |
| 171. | | | | Winter | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 171. |
| 172. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 172. |
| 173. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 173. |
| 174. | | | | | First 5,000 kWh: Secondary | 0.11512 | /kWh | First 5,000 kWh: Secondary | 0.11580 | /kWh | 0.00068 | /kWh | 174. |
| 175. | | | | | All remaining kWh: Secondary | 0.05501 | /kWh | All remaining kWh: Secondary | 0.05501 | /kWh | - | /kWh | 175. |
| 176. | | | | | First 5,000 kWh: Primary | 0.11189 | /kWh | First 5,000 kWh: Primary | 0.11252 | /kWh | 0.00063 | /kWh | 176. |
| 177 | | | | | All remaining kWh: Primary | 0.05179 | /kWh | All remaining kWh: Primary | 0.05179 | /kWh | - | /kWh | 177. |
| 178. | | | | | | | | | | | | | 178. |
| 179. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 179. |
| 180. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 180. |
| 181. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 181. |
| 182. | | | | | | | | | | | | | 182. |
| 183. | E-32 S | General Service | Rate | Summer | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 183. |
| 184. | | 21-100 kW | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 184. |
| 185. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 185. |
| 186. | | | | | First 100 kW: Secondary | 9.675 | /kW | First 100 kW: Secondary | 9.837 | /kW | 0.162 | /kW | 186. |
| 187. | | | | | All remaining kW: Secondary | 5.146 | /kW | All remaining kW: Secondary | 5.217 | /kW | 0.071 | /kW | 187. |
| 188. | | | | | First 100 kW: Primary | 8.976 | /kW | First 100 kW: Primary | 9.124 | /kW | 0.148 | /kW | 188. |
| 189. | | | | | All remaining kW: Primary | 4.448 | /kW | All remaining kW: Primary | 4.505 | /kW | 0.057 | /kW | 189. |
| 190. | | | | | First 200 kWh per kW | 0.10403 | /kWh | First 200 kWh per kW | 0.10655 | /kWh | 0.00252 | /kWh | 190. |
| 191. | | | | | All remaining kWh | 0.06083 | /kWh | All remaining kWh | 0.06209 | /kWh | 0.00126 | /kWh | 191. |
| 192. | | | | | | | | | | | | | 192. |
| 193. | | | Rate | Winter | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 193. |
| 194. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 194. |
| 195. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 195. |
| 196. | | | | | First 100 kW: Secondary | 9.675 | /kW | First 100 kW: Secondary | 9.837 | /kW | 0.162 | /kW | 196. |
| 197 | | | | | All remaining kW: Secondary | 5.146 | /kW | All remaining kW: Secondary | 5.217 | /kW | 0.071 | /kW | 197. |
| 198 | | | | | First 100 kW: Primary | 8.976 | /kW | First 100 kW: Primary | 9.124 | /kW | 0.148 | /kW | 198. |
| 199 | | | | | All remaining kW: Primary | 4.448 | /kW | All remaining kW: Primary | 4.505 | /kW | 0.057 | /kW | 199. |
| 200 | | | | | First 200 kWh per kW | 0.08689 | /kWh | First 200 kWh per kW | 0.08891 | /kWh | 0.00202 | /kWh | 200. |
| 201. | | | | | All remaining kWh | 0.04369 | /kWh | All remaining kWh | 0.04445 | /kWh | 0.00076 | /kWh | 201. |
| 202. | | | | | | | | | | | | | 202. |
| 203. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | (0.01400) | /day | 203. |
| 204. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.00400 | /day | 204. |
| 205. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.06200 | /day | 205. |

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 1/01/2010.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 206. | | | | | Minimum Demand Charge: | 2.180 | /kW | Minimum Demand Charge: | 2.180 | /kW | - | /kW | 206. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| Line No. | (A) Rate Schedule | (B) Description | (C) Billing Designation | (D) Season | (E) Present Rates Block | (F) (G) Present Rates Rates | (H) Proposed Rates Block | (I) (J) Proposed Rates Rates | (K) (L) Change (I) - (F) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|
| 207 | | | | | | | | | | 207. |
| 208. | E-32 M | General Service | Rate | Summer | BSC: Self-Contained Meters | $ 0.672 /day | BSC: Self-Contained Meters | $ 0.658 /day | $ (0.014) /day | 208. |
| 209. | | 101-400 kW | | | BSC: Instrument-rated Meters | 1.324 /day | BSC: Instrument-rated Meters | 1.328 /day | 0.004 /day | 209. |
| 210. | | | | | BSC: Primary Meters | 3.415 /day | BSC: Primary Meters | 3.477 /day | 0.062 /day | 210. |
| 211. | | | | | BSC: Transmission Meters | 26.163 /day | BSC: Transmission Meters | 26.855 /day | 0.692 /day | 211. |
| 212. | | | | | First 100 kW: Secondary | 9.597 /kW | First 100 kW: Secondary | 9.623 /kW | 0.026 /kW | 212. |
| 213. | | | | | All remaining kW: Secondary | 5.105 /kW | All remaining kW: Secondary | 5.229 /kW | 0.124 /kW | 213. |
| 214. | | | | | First 100 kW: Primary | 8.905 /kW | First 100 kW: Primary | 8.929 /kW | 0.024 /kW | 214. |
| 215. | | | | | All remaining kW: Primary | 4.412 /kW | All remaining kW: Primary | 4.512 /kW | 0.100 /kW | 215. |
| 216. | | | | | First 100 kW: Transmission | 6.942 /kW | First 100 kW: Transmission | 7.131 /kW | 0.189 /kW | 216. |
| 217 | | | | | All remaining kW: Transmission | 2.450 /kW | All remaining kW: Transmission | 2.453 /kW | 0.003 /kW | 217. |
| 218. | | | | | First 200 kWh per kW | 0.10320 /kWh | First 200 kWh per kW | 0.10308 /kWh | (0.00012) /kWh | 218. |
| 219 | | | | | All remaining kWh | 0.06034 /kWh | All remaining kWh | 0.06008 /kWh | (0.00026) /kWh | 219. |
| 220. | | | | | | | | | | 220. |
| 221. | | | Rate | Winter | BSC: Self-Contained Meters | $ 0.672 /day | BSC: Self-Contained Meters | $ 0.658 /day | $ (0.014) /day | 221. |
| 222. | | | | | BSC: Instrument-rated Meters | 1.324 /day | BSC: Instrument-rated Meters | 1.328 /day | 0.004 /day | 222. |
| 223. | | | | | BSC: Primary Meters | 3.415 /day | BSC: Primary Meters | 3.477 /day | 0.062 /day | 223. |
| 224 | | | | | BSC: Transmission Meters | 26.163 /day | BSC: Transmission Meters | 26.855 /day | 0.692 /day | 224. |
| 225 | | | | | First 100 kW: Secondary | 9.597 /kW | First 100 kW: Secondary | 9.623 /kW | 0.026 /kW | 225. |
| 226 | | | | | All remaining kW: Secondary | 5.105 /kW | All remaining kW: Secondary | 5.229 /kW | 0.124 /kW | 226. |
| 227. | | | | | First 100 kW: Primary | 8.905 /kW | First 100 kW: Primary | 8.929 /kW | 0.024 /kW | 227. |
| 228. | | | | | All remaining kW: Primary | 4.412 /kW | All remaining kW: Primary | 4.512 /kW | 0.100 /kW | 228. |
| 229. | | | | | First 100 kW: Transmission | 6.942 /kW | First 100 kW: Transmission | 7.131 /kW | 0.189 /kW | 229. |
| 230. | | | | | All remaining kW: Transmission | 2.450 /kW | All remaining kW: Transmission | 2.453 /kW | 0.003 /kW | 230. |
| 231. | | | | | First 200 kWh per kW | 0.08619 /kWh | First 200 kWh per kW | 0.08601 /kWh | (0.00018) /kWh | 231. |
| 232. | | | | | All remaining kWh | 0.04334 /kWh | All remaining kWh | 0.04302 /kWh | (0.00032) /kWh | 232. |
| 233. | | | | | | | | | | 233. |
| 234. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 0.672 /day | BSC: Self-Contained Meters | $ 0.658 /day | $ (0.014) /day | 234. |
| 235. | | | | | BSC: Instrument-rated Meters | 1.324 /day | BSC: Instrument-rated Meters | 1.328 /day | 0.004 /day | 235. |
| 236. | | | | | BSC: Primary Meters | 3.415 /day | BSC: Primary Meters | 3.477 /day | 0.062 /day | 236. |
| 237. | | | | | BSC: Transmission Meters | 26.163 /day | BSC: Transmission Meters | 26.855 /day | 0.692 /day | 237. |
| 238. | | | | | Minimum Demand Charge: | 2.162 /kW | Minimum Demand Charge: | 2.162 /kW | - /kW | 238. |
| 239. | | | | | | | | | | 239. |
| 240. | E-32 L | General Service | Rate | Summer | BSC: Self-Contained Meters | $ 1.068 /day | BSC: Self-Contained Meters | $ 0.658 /day | $ (0.410) /day | 240. |
| 241. | | 401 kW and above | | | BSC: Instrument-rated Meters | 1.627 /day | BSC: Instrument-rated Meters | 1.328 /day | (0.299) /day | 241. |
| 242 | | | | | BSC: Primary Meters | 3.419 /day | BSC: Primary Meters | 3.477 /day | 0.058 /day | 242. |
| 243. | | | | | BSC: Transmission Meters | 22.915 /day | BSC: Transmission Meters | 26.855 /day | 3.940 /day | 243. |
| 244. | | | | | First 100 kW: Secondary | 9.384 /kW | First 100 kW: Secondary | 9.432 /kW | 0.048 /kW | 244. |
| 245. | | | | | All remaining kW: Secondary | 4.993 /kW | All remaining kW: Secondary | 5.014 /kW | 0.021 /kW | 245. |
| 246. | | | | | First 100 kW: Primary | 8.703 /kW | First 100 kW: Primary | 8.746 /kW | 0.043 /kW | 246. |
| 247 | | | | | All remaining kW: Primary | 4.315 /kW | All remaining kW: Primary | 4.332 /kW | 0.017 /kW | 247. |
| 248 | | | | | First 100 kW: Transmission | 6.788 /kW | First 100 kW: Transmission | 6.820 /kW | 0.032 /kW | 248. |
| 249. | | | | | All remaining kW: Transmission | 2.396 /kW | All remaining kW: Transmission | 2.401 /kW | 0.005 /kW | 249. |
| 250. | | | | | First 200 kWh per kW | 0.10093 /kWh | First 200 kWh per kW | 0.10108 /kWh | 0.00015 /kWh | 250. |
| 251. | | | | | All remaining kWh | 0.05902 /kWh | All remaining kWh | 0.05892 /kWh | (0.00010) /kWh | 251. |
| 252. | | | | | | | | | | 252. |
| 253. | | | Rate | Winter | BSC: Self-Contained Meters | $ 1.068 /day | BSC: Self-Contained Meters | $ 0.658 /day | $ (0.410) /day | 253. |
| 254. | | | | | BSC: Instrument-rated Meters | 1.627 /day | BSC: Instrument-rated Meters | 1.328 /day | (0.299) /day | 254. |
| 255. | | | | | BSC: Primary Meters | 3.419 /day | BSC: Primary Meters | 3.477 /day | 0.058 /day | 255. |
| 256. | | | | | BSC: Transmission Meters | 22.915 /day | BSC: Transmission Meters | 26.855 /day | 3.940 /day | 256. |
| 257 | | | | | First 100 kW: Secondary | 9.384 /kW | First 100 kW: Secondary | 9.432 /kW | 0.048 /kW | 257. |
| 258. | | | | | All remaining kW: Secondary | 4.993 /kW | All remaining kW: Secondary | 5.014 /kW | 0.021 /kW | 258. |
| 259. | | | | | First 100 kW: Primary | 8.703 /kW | First 100 kW: Primary | 8.746 /kW | 0.043 /kW | 259. |
| 260. | | | | | All remaining kW: Primary | 4.315 /kW | All remaining kW: Primary | 4.332 /kW | 0.017 /kW | 260. |
| 261. | | | | | First 100 kW: Transmission | 6.788 /kW | First 100 kW: Transmission | 6.820 /kW | 0.032 /kW | 261. |
| 262. | | | | | All remaining kW: Transmission | 2.396 /kW | All remaining kW: Transmission | 2.401 /kW | 0.005 /kW | 262. |
| 263. | | | | | First 200 kWh per kW | 0.08430 /kWh | First 200 kWh per kW | 0.08435 /kWh | 0.00005 /kWh | 263. |
| 264. | | | | | All remaining kWh | 0.04239 /kWh | All remaining kWh | 0.04219 /kWh | (0.00020) /kWh | 264. |
| 265. | | | | | | | | | | 265. |
| 266. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 1.068 /day | BSC: Self-Contained Meters | 0.658 /day | $ (0.410) /day | 266. |
| 267. | | | | | BSC: Instrument-rated Meters | 1.627 /day | BSC: Instrument-rated Meters | 1.328 /day | (0.299) /day | 267. |
| 268. | | | | | BSC: Primary Meters | 3.419 /day | BSC: Primary Meters | 3.477 /day | 0.058 /day | 268. |
| 269. | | | | | BSC: Transmission Meters | 22.915 /day | BSC: Transmission Meters | 26.855 /day | 3.940 /day | 269. |
| 270. | | | | | Minimum Demand Charge. | 2.115 /kW | First 100 kW: Secondary | 9.432 /kW | 9.432 /kW | 270. |
| 271. | | | | | | | All remaining kW: Secondary | 5.014 /kW | 5.014 /kW | 271. |
| 272. | | | | | | | First 100 kW: Primary | 8.746 /kW | 8.746 /kW | 272. |
| 273. | | | | | | | All remaining kW: Primary | 4.332 /kW | 4.332 /kW | 273. |
| 274 | | | | | | | First 100 kW: Transmission | 6.820 /kW | 6.820 /kW | 274. |
| 275. | | | | | | | All remaining kW: Transmission | 2.401 /kW | 2.401 /kW | 275. |

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 1/01/2010.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| Line No. | (A) Rate Schedule | (B) Description | (C) Billing Designation | (D) Season | (E) Present Rates: Block | (F) Present Rates: Rates | (G) | (H) Proposed Rates: Block | (I) Proposed Rates: Rates | (J) | (K) Change (I) - (F) | (L) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 276. | | | | | | | | | | | | | 276. |
| 277. | E-32TOU XS | General Service | Rate | Summer | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.052) | /day | 277. |
| 278. | | Time of Use | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 278. |
| 279. | | 20 kW or Less | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 279. |
| 280. | | | | | First 5,000 On-Peak kWh: Secondary | 0.16831 | /kWh | First 5,000 On-Peak kWh: Secondary | 0.16865 | /kWh | 0.00034 | /kWh | 280. |
| 281. | | | | | All remaining On-Peak kWh: Secondary | 0.08318 | /kWh | All remaining On-Peak kWh: Secondary | 0.08335 | /kWh | 0.00017 | /kWh | 281. |
| 282. | | | | | First 5,000 Off-Peak kWh: Secondary | 0.12438 | /kWh | First 5,000 Off-Peak kWh: Secondary | 0.12463 | /kWh | 0.00025 | /kWh | 282. |
| 283. | | | | | All remaining Off-Peak kWh: Secondary | 0.04459 | /kWh | All remaining Off-Peak kWh: Secondary | 0.04468 | /kWh | 0.00009 | /kWh | 283. |
| 284. | | | | | First 5,000 On-Peak kWh: Primary | 0.16498 | /kWh | First 5,000 On-Peak kWh: Primary | 0.16531 | /kWh | 0.00033 | /kWh | 284. |
| 285. | | | | | All remaining On-Peak kWh: Primary | 0.07907 | /kWh | All remaining On-Peak kWh: Primary | 0.07923 | /kWh | 0.00016 | /kWh | 285. |
| 286. | | | | | First 5,000 Off-Peak kWh: Primary | 0.12105 | /kWh | First 5,000 Off-Peak kWh: Primary | 0.12129 | /kWh | 0.00024 | /kWh | 286. |
| 287. | | | | | All remaining Off-Peak kWh: Primary | 0.04126 | /kWh | All remaining Off-Peak kWh: Primary | 0.04134 | /kWh | 0.00008 | /kWh | 287. |
| 288. | | | | | | | | | | | | | 288. |
| 289. | | | | Winter | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.052) | /day | 289. |
| 290. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 290. |
| 291. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 291. |
| 292. | | | | | First 5,000 On-Peak kWh: Secondary | 0.15082 | /kWh | First 5,000 On-Peak kWh: Secondary | 0.15112 | /kWh | 0.00030 | /kWh | 292. |
| 293. | | | | | All remaining On-Peak kWh: Secondary | 0.06565 | /kWh | All remaining On-Peak kWh: Secondary | 0.06578 | /kWh | 0.00013 | /kWh | 293. |
| 294. | | | | | First 5,000 Off-Peak kWh: Secondary | 0.10686 | /kWh | First 5,000 Off-Peak kWh: Secondary | 0.10707 | /kWh | 0.00021 | /kWh | 294. |
| 295. | | | | | All remaining Off-Peak kWh: Secondary | 0.03181 | /kWh | All remaining Off-Peak kWh: Secondary | 0.03187 | /kWh | 0.00006 | /kWh | 295. |
| 296. | | | | | First 5,000 On-Peak kWh: Primary | 0.14749 | /kWh | First 5,000 On-Peak kWh: Primary | 0.14778 | /kWh | 0.00029 | /kWh | 296. |
| 297. | | | | | All remaining On-Peak kWh: Primary | 0.06154 | /kWh | All remaining On-Peak kWh: Primary | 0.06166 | /kWh | 0.00012 | /kWh | 297. |
| 298. | | | | | First 5,000 Off-Peak kWh: Primary | 0.10353 | /kWh | First 5,000 Off-Peak kWh: Primary | 0.10374 | /kWh | 0.00021 | /kWh | 298. |
| 299. | | | | | All remaining Off-Peak kWh: Primary | 0.02848 | /kWh | All remaining Off-Peak kWh: Primary | 0.02854 | /kWh | 0.00006 | /kWh | 299. |
| 300. | | | | | | | | | | | | | 300. |
| 301. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.052) | /day | 301. |
| 302. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 302. |
| 303. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 303. |
| 304. | | | | | | | | | | | | | 304. |
| 305. | E-32TOU S | General Service | Rate | Summer | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.052) | /day | 305. |
| 306. | | Time of Use | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 306. |
| 307. | | 21-100 kW | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 307. |
| 308. | | | | | First 100 On-Peak kW: Secondary | 14.322 | /kW | First 100 On-Peak kW: Secondary | 14.322 | /kW | - | /kW | 308. |
| 309. | | | | | All remaining On-Peak kW: Secondary | 9.725 | /kW | All remaining On-Peak kW: Secondary | 9.725 | /kW | - | /kW | 309. |
| 310. | | | | | First 100 Off-Peak kW: Secondary | 5.492 | /kW | First 100 Off-Peak kW: Secondary | 5.492 | /kW | - | /kW | 310. |
| 311. | | | | | All remaining Off-Peak kW: Secondary | 3.059 | /kW | All remaining Off-Peak kW: Secondary | 3.059 | /kW | - | /kW | 311. |
| 312. | | | | | First 100 On-Peak kW: Primary | 13.863 | /kW | First 100 On-Peak kW: Primary | 13.863 | /kW | - | /kW | 312. |
| 313. | | | | | All remaining On-Peak kW: Primary | 9.657 | /kW | All remaining On-Peak kW: Primary | 9.657 | /kW | - | /kW | 313. |
| 314. | | | | | First 100 Off-Peak kW: Primary | 4.916 | /kW | First 100 Off-Peak kW: Primary | 4.916 | /kW | - | /kW | 314. |
| 315. | | | | | All remaining Off-Peak kW: Primary | 2.979 | /kW | All remaining Off-Peak kW: Primary | 2.979 | /kW | - | /kW | 315. |
| 316. | | | | | All On-Peak kWh: | 0.07291 | /kWh | All On-Peak kWh: | 0.07291 | /kWh | - | /kWh | 316. |
| 317. | | | | | All Off-Peak kWh: | 0.05794 | /kWh | All Off-Peak kWh: | 0.05794 | /kWh | - | /kWh | 317. |
| 318. | | | | | | | | | | | | | 318. |
| 319. | | | | Winter | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.052) | /day | 319. |
| 320. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 320. |
| 321. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 321. |
| 322. | | | | | First 100 On-Peak kW: Secondary | 14.322 | /kW | First 100 On-Peak kW: Secondary | 14.322 | /kW | - | /kW | 322. |
| 323. | | | | | All remaining On-Peak kW: Secondary | 9.725 | /kW | All remaining On-Peak kW: Secondary | 9.725 | /kW | - | /kW | 323. |
| 324. | | | | | First 100 Off-Peak kW: Secondary | 5.492 | /kW | First 100 Off-Peak kW: Secondary | 5.492 | /kW | - | /kW | 324. |
| 325. | | | | | All remaining Off-Peak kW: Secondary | 3.059 | /kW | All remaining Off-Peak kW: Secondary | 3.059 | /kW | - | /kW | 325. |
| 326. | | | | | First 100 On-Peak kW: Primary | 13.863 | /kW | First 100 On-Peak kW: Primary | 13.863 | /kW | - | /kW | 326. |
| 327. | | | | | All remaining On-Peak kW: Primary | 9.657 | /kW | All remaining On-Peak kW: Primary | 9.657 | /kW | - | /kW | 327. |
| 328. | | | | | First 100 Off-Peak kW: Primary | 4.916 | /kW | First 100 Off-Peak kW: Primary | 4.916 | /kW | - | /kW | 328. |
| 329. | | | | | All remaining Off-Peak kW: Primary | 2.979 | /kW | All remaining Off-Peak kW: Primary | 2.979 | /kW | - | /kW | 329. |
| 330. | | | | | All On-Peak kWh: | 0.05586 | /kWh | All On-Peak kWh: | 0.05586 | /kWh | - | /kWh | 330. |
| 331. | | | | | All Off-Peak kWh: | 0.04089 | /kWh | All Off-Peak kWh: | 0.04089 | /kWh | - | /kWh | 331. |
| 332. | | | | | | | | | | | | | 332. |
| 333. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | (0.052) | /day | 333. |
| 334. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 334. |
| 335. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | N/A | /day | 335. |
| 336. | | | | | Minimum Demand Charge: | 2.206 | /kW | Minimum Demand Charge: | 2.206 | /kW | - | /kW | 336. |

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 1/01/2010.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 337. | | | | | | | | | | | | | 337. |
| 338. | E-32TOU M | General Service | Rate | Summer | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.052) | /day | 338. |
| 339. | | Time of Use | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 339. |
| 340. | | 101- 400 kW | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 340. |
| 341. | | | | | BSC: Transmission Meters | 26.163 | /day | BSC: Transmission Meters | 26.855 | /day | 0.692 | /day | 341. |
| 342. | | | | | First 100 On-Peak kW: Secondary | 14.209 | /kW | First 100 On-Peak kW: Secondary | 14.209 | /kW | - | /kW | 342. |
| 343. | | | | | All remaining On-Peak kW: Secondary | 9.649 | /kW | All remaining On-Peak kW: Secondary | 9.649 | /kW | - | /kW | 343. |
| 344. | | | | | First 100 Residual kW: Secondary | 5.449 | /kW | First 100 Off-Peak kW: Secondary | 5.449 | /kW | - | /kW | 344. |
| 345. | | | | | All remaining Residual kW: Secondary | 3.034 | /kW | All remaining Off-Peak kW: Secondary | 3.034 | /kW | - | /kW | 345. |
| 346. | | | | | First 100 On-Peak kW: Primary | 13.753 | /kW | First 100 On-Peak kW: Primary | 13.753 | /kW | - | /kW | 346. |
| 347. | | | | | All remaining On-Peak kW: Primary | 9.581 | /kW | All remaining On-Peak kW: Primary | 9.581 | /kW | - | /kW | 347. |
| 348. | | | | | First 100 Residual kW: Primary | 4.877 | /kW | First 100 Off-Peak kW: Primary | 4.877 | /kW | - | /kW | 348. |
| 349. | | | | | All remaining Residual kW: Primary | 2.955 | /kW | All remaining Off-Peak kW: Primary | 2.955 | /kW | - | /kW | 349. |
| 350. | | | | | First 100 On-Peak kW: Transmission | 12.938 | /kW | First 100 On-Peak kW: Transmission | 12.938 | /kW | - | /kW | 350. |
| 351. | | | | | All remaining On-Peak kW: Transmission | 9.300 | /kW | All remaining On-Peak kW: Transmission | 9.300 | /kW | - | /kW | 351. |
| 352. | | | | | First 100 Residual kW: Transmission | 4.232 | /kW | First 100 Off-Peak kW: Transmission | 4.232 | /kW | - | /kW | 352. |
| 353. | | | | | All remaining Residual kW: Transmission | 2.849 | /kW | All remaining Off-Peak kW: Transmission | 2.849 | /kW | - | /kW | 353. |
| 354. | | | | | All On-Peak kWh: | 0.07233 | /kWh | All On-Peak kWh: | 0.07233 | /kWh | - | /kWh | 354. |
| 355. | | | | | All Off-Peak kWh: | 0.05748 | /kWh | All Off-Peak kWh: | 0.05748 | /kWh | - | /kWh | 355. |
| 356. | | | | | | | | | | | | | 356. |
| 357. | | | | Winter | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.052) | /day | 357. |
| 358. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 358. |
| 359. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 359. |
| 360. | | | | | BSC: Transmission Meters | 26.163 | /day | BSC: Transmission Meters | 26.855 | /day | 0.692 | /day | 360. |
| 361. | | | | | First 100 On-Peak kW: Secondary | 14.209 | /kW | First 100 On-Peak kW: Secondary | 14.209 | /kW | - | /kW | 361. |
| 362. | | | | | All remaining On-Peak kW: Secondary | 9.649 | /kW | All remaining On-Peak kW: Secondary | 9.649 | /kW | - | /kW | 362. |
| 363. | | | | | First 100 Residual kW: Secondary | 5.449 | /kW | First 100 Off-Peak kW: Secondary | 5.449 | /kW | - | /kW | 363. |
| 364. | | | | | All remaining Residual kW: Secondary | 3.034 | /kW | All remaining Off-Peak kW: Secondary | 3.034 | /kW | - | /kW | 364. |
| 365. | | | | | First 100 On-Peak kW: Primary | 13.753 | /kW | First 100 On-Peak kW: Primary | 13.753 | /kW | - | /kW | 365. |
| 366. | | | | | All remaining On-Peak kW: Primary | 9.581 | /kW | All remaining On-Peak kW: Primary | 9.581 | /kW | - | /kW | 366. |
| 367. | | | | | First 100 Residual kW: Primary | 4.877 | /kW | First 100 Off-Peak kW: Primary | 4.877 | /kW | - | /kW | 367. |
| 368. | | | | | All remaining Residual kW: Primary | 2.955 | /kW | All remaining Off-Peak kW: Primary | 2.955 | /kW | - | /kW | 368. |
| 369. | | | | | First 100 On-Peak kW: Transmission | 12.938 | /kW | First 100 On-Peak kW: Transmission | 12.938 | /kW | - | /kW | 369. |
| 370. | | | | | All remaining On-Peak kW: Transmission | 9.300 | /kW | All remaining On-Peak kW: Transmission | 9.300 | /kW | - | /kW | 370. |
| 371. | | | | | First 100 Residual kW: Transmission | 4.232 | /kW | First 100 Off-Peak kW: Transmission | 4.232 | /kW | - | /kW | 371. |
| 372. | | | | | All remaining Residual kW: Transmission | 2.849 | /kW | All remaining Off-Peak kW: Transmission | 2.849 | /kW | - | /kW | 372. |
| 373. | | | | | All On-Peak kWh: | 0.05542 | /kWh | All On-Peak kWh: | 0.05542 | /kWh | - | /kWh | 373. |
| 374. | | | | | All Off-Peak kWh: | 0.04057 | /kWh | All Off-Peak kWh: | 0.04057 | /kWh | - | /kWh | 374. |
| 375. | | | | | | | | | | | | | 375. |
| 376. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 0.710 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | (0.052) | /day | 376. |
| 377. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.328 | /day | 0.004 | /day | 377. |
| 378. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.477 | /day | 0.062 | /day | 378. |
| 379. | | | | | BSC: Transmission Meters | 26.163 | /day | BSC: Transmission Meters | 26.855 | /day | 0.692 | /day | 379. |
| 380. | | | | | Minimum Demand Charge: | 2.189 | /kW | Minimum Demand Charge: | 2.189 | /kW | - | /kW | 380. |

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 1/01/2010.

Recap Schedules:
N/A

# ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND RUCO PROPOSED RATES

### TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | | (G) | (H) | (I) | | (J) | (K) | | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | | Proposed Rates | | | | | | | |
| Line No | Rate Schedule | Description | Billing Designation | Season | Block | | Rates | | Block | | Rates | | | Change (I) - (F) | | Line No. |
| 381. | | | | | | | | | | | | | | | | 381. |
| 382. | E-32TOU L | General Service | Rate | Summer | BSC: Self-Contained Meters | $ | 0.710 | /day | BSC: Self-Contained Meters | $ | 0.658 | /day | $ | (0.052) | /day | 382. |
| 383. | | Time of Use | | | BSC: Instrument-rated Meters | | 1.324 | /day | BSC: Instrument-rated Meters | | 1.328 | /day | | 0.004 | /day | 383. |
| 384. | | 401 kW and above | | | BSC: Primary Meters | | 3.415 | /day | BSC: Primary Meters | | 3.477 | /day | | 0.062 | /day | 384. |
| 385. | | | | | BSC: Transmission Meters | | 26.163 | /day | BSC: Transmission Meters | | 26.855 | /day | | 0.692 | /day | 385. |
| 386. | | | | | First 100 On-Peak kW: Secondary | | 13.901 | /kW | First 100 On-Peak kW: Secondary | | 13.901 | /kW | | - | /kW | 386. |
| 387. | | | | | All remaining On-Peak kW: Secondary | | 9.439 | /kW | All remaining On-Peak kW: Secondary | | 9.439 | /kW | | - | /kW | 387. |
| 388. | | | | | First 100 Residual kW: Secondary | | 5.331 | /kW | First 100 Off-Peak kW: Secondary | | 5.331 | /kW | | - | /kW | 388. |
| 389. | | | | | All remaining Residual kW: Secondary | | 2.969 | /kW | All remaining Off-Peak kW: Secondary | | 2.969 | /kW | | - | /kW | 389. |
| 390. | | | | | First 100 On-Peak kW: Primary | | 13.455 | /kW | First 100 On-Peak kW: Primary | | 13.455 | /kW | | - | /kW | 390. |
| 391. | | | | | All remaining On-Peak kW: Primary | | 9.373 | /kW | All remaining On-Peak kW: Primary | | 9.373 | /kW | | - | /kW | 391. |
| 392. | | | | | First 100 Residual kW: Primary | | 4.771 | /kW | First 100 Off-Peak kW: Primary | | 4.771 | /kW | | - | /kW | 392. |
| 393. | | | | | All remaining Residual kW: Primary | | 2.891 | /kW | All remaining Off-Peak kW: Primary | | 2.891 | /kW | | - | /kW | 393. |
| 394. | | | | | First 100 On-Peak kW: Transmission | | 12.658 | /kW | First 100 On-Peak kW: Transmission | | 12.658 | /kW | | - | /kW | 394. |
| 395. | | | | | All remaining On-Peak kW: Transmission | | 9.098 | /kW | All remaining On-Peak kW: Transmission | | 9.098 | /kW | | - | /kW | 395. |
| 396. | | | | | First 100 Residual kW: Transmission | | 4.140 | /kW | First 100 Off-Peak kW: Transmission | | 4.140 | /kW | | - | /kW | 396. |
| 397. | | | | | All remaining Residual kW: Transmission | | 2.787 | /kW | All remaining Off-Peak kW: Transmission | | 2.787 | /kW | | - | /kW | 397. |
| 398. | | | | | All On-Peak kWh: | | 0.07076 | /kWh | All On-Peak kWh: | | 0.07076 | /kWh | | - | /kWh | 398. |
| 399. | | | | | All Off-Peak kWh: | | 0.05623 | /kWh | All Off-Peak kWh: | | 0.05623 | /kWh | | - | /kWh | 399. |
| 400. | | | | | | | | | | | | | | | | 400. |
| 401. | | | | Winter | BSC: Self-Contained Meters | $ | 0.710 | /day | BSC: Self-Contained Meters | $ | 0.658 | /day | $ | (0.052) | /day | 401. |
| 402. | | | | | BSC: Instrument-rated Meters | | 1.324 | /day | BSC: Instrument-rated Meters | | 1.328 | /day | | 0.004 | /day | 402. |
| 403. | | | | | BSC: Primary Meters | | 3.415 | /day | BSC: Primary Meters | | 3.477 | /day | | 0.062 | /day | 403. |
| 404. | | | | | BSC: Transmission Meters | | 26.163 | /day | BSC: Transmission Meters | | 26.855 | /day | | 0.692 | /day | 404. |
| 405. | | | | | First 100 On-Peak kW: Secondary | | 13.901 | /kW | First 100 On-Peak kW: Secondary | | 13.901 | /kW | | - | /kW | 405. |
| 406. | | | | | All remaining On-Peak kW: Secondary | | 9.439 | /kW | All remaining On-Peak kW: Secondary | | 9.439 | /kW | | - | /kW | 406. |
| 407. | | | | | First 100 Residual kW: Secondary | | 5.331 | /kW | First 100 Off-Peak kW: Secondary | | 5.331 | /kW | | - | /kW | 407. |
| 408. | | | | | All remaining Residual kW: Secondary | | 2.969 | /kW | All remaining Off-Peak kW: Secondary | | 2.969 | /kW | | - | /kW | 408. |
| 409. | | | | | First 100 On-Peak kW: Primary | | 13.455 | /kW | First 100 On-Peak kW: Primary | | 13.455 | /kW | | - | /kW | 409. |
| 410. | | | | | All remaining On-Peak kW: Primary | | 9.373 | /kW | All remaining On-Peak kW: Primary | | 9.373 | /kW | | - | /kW | 410. |
| 411. | | | | | First 100 Residual kW: Primary | | 4.771 | /kW | First 100 Off-Peak kW: Primary | | 4.771 | /kW | | - | /kW | 411. |
| 412. | | | | | All remaining Residual kW: Primary | | 2.891 | /kW | All remaining Off-Peak kW: Primary | | 2.891 | /kW | | - | /kW | 412. |
| 413. | | | | | First 100 On-Peak kW: Transmission | | 12.658 | /kW | First 100 On-Peak kW: Transmission | | 12.658 | /kW | | - | /kW | 413. |
| 414. | | | | | All remaining On-Peak kW: Transmission | | 9.098 | /kW | All remaining On-Peak kW: Transmission | | 9.098 | /kW | | - | /kW | 414. |
| 415. | | | | | First 100 Residual kW: Transmission | | 4.140 | /kW | First 100 Off-Peak kW: Transmission | | 4.140 | /kW | | - | /kW | 415. |
| 416. | | | | | All remaining Residual kW: Transmission | | 2.787 | /kW | All remaining Off-Peak kW: Transmission | | 2.787 | /kW | | - | /kW | 416. |
| 417. | | | | | All On-Peak kWh: | | 0.05421 | /kWh | All On-Peak kWh: | | 0.05421 | /kWh | | - | /kWh | 417. |
| 418. | | | | | All Off-Peak kWh: | | 0.03968 | /kWh | All Off-Peak kWh: | | 0.03968 | /kWh | | - | /kWh | 418. |
| 419. | | | | | | | | | | | - | | | | | 419. |
| 420. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ | 0.710 | /day | N/A | | N/A | /day | | N/A | /day | 420. |
| 421. | | | | | BSC: Instrument-rated Meters | | 1.324 | /day | N/A | | N/A | /day | | N/A | /day | 421. |
| 422. | | | | | BSC: Primary Meters | | 3.415 | /day | N/A | | N/A | /day | | N/A | /day | 422. |
| 423. | | | | | BSC: Transmission Meters | | 26.163 | /day | N/A | | N/A | /day | | N/A | /day | 423. |
| 424. | | | | | Minimum Demand Charge: | | 2.141 | /kW | N/A | | N/A | /kW | | N/A | /kW | 424. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES

COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 425. | | | | | | | | | | | | | 425. |
| 426. | E-34 | Extra Large | Rate | Sum & Win | BSC: Self-Contained Meters | $ 1.135 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.477) | /day | 426. |
| 427. | | General Service | | | BSC: Instrument-rated Meters | 1.776 | /day | BSC: Instrument-rated Meters | 1.328 | /day | (0.448) | /day | 427. |
| 428. | | | | | BSC: Primary Meters | 3.828 | /day | BSC: Primary Meters | 3.477 | /day | (0.351) | /day | 428. |
| 429. | | | | | BSC: Transmission Meters | 26.161 | /day | BSC: Transmission Meters | 26.855 | /day | 0.694 | /day | 429. |
| 430. | | | | | All kW: Secondary | 17.377 | /kW | All kW: Secondary | 17.377 | /kW | - | /kW | 430. |
| 431. | | | | | All kW: Primary | 16.478 | /kW | All kW: Primary | 16.478 | /kW | - | /kW | 431. |
| 432. | | | | | All kW: Primary on Military Bases | 12.787 | /kW | All kW: Primary on Military Bases | 12.005 | /kW | (0.782) | /kW | 432. |
| 433. | | | | | All kW: Transmission | 12.005 | /kW | All kW: Transmission | 11.749 | /kW | (0.256) | /kW | 433. |
| 434. | | | | | All kWh | 0.04220 | /kWh | All kWh | 0.04220 | /kWh | - | /kWh | 434. |
| 435. | | | | | | | | | | | | | 435. |
| 436. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 1.135 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.477) | /day | 436. |
| 437. | | | | | BSC: Instrument-rated Meters | 1.776 | /day | BSC: Instrument-rated Meters | 1.328 | /day | (0.448) | /day | 437. |
| 438. | | | | | BSC: Primary Meters | 3.828 | /day | BSC: Primary Meters | 3.477 | /day | (0.351) | /day | 438. |
| 439. | | | | | BSC: Transmission Meters | 26.161 | /day | BSC: Transmission Meters | 26.855 | /day | 0.694 | /day | 439. |
| 440. | | | | | Demand Charge: Secondary | 17.377 | /kW | Demand Charge: Secondary | 17.377 | /kW | - | /kW | 440. |
| 441. | | | | | Demand Charge: Primary | 16.478 | /kW | Demand Charge: Primary | 16.478 | /kW | - | /kW | 441. |
| 442. | | | | | Demand Charge: Primary on Military Bases | 12.787 | /kW | Demand Charge: Primary on Military Bases | 12.005 | /kW | (0.782) | /kW | 442. |
| 443. | | | | | Demand Charge: Transmission | 12.005 | /kW | Demand Charge: Transmission | 11.749 | /kW | (0.256) | /kW | 443. |
| 444. | | | | | | | | | | | | | 444. |
| 445. | E-35 | Extra Large | Rate | Sum & Win | BSC: Self-Contained Meters | $ 1.183 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.525) | /day | 445. |
| 446. | | General Service | | | BSC: Instrument-rated Meters | 1.795 | /day | BSC: Instrument-rated Meters | 1.328 | /day | (0.467) | /day | 446. |
| 447. | | Time Of Use | | | BSC: Primary Meters | 3.881 | /day | BSC: Primary Meters | 3.477 | /day | (0.404) | /day | 447. |
| 448. | | | | | BSC: Transmission Meters | 26.574 | /day | BSC: Transmission Meters | 26.855 | /day | 0.281 | /day | 448. |
| 449. | | | | | All On-Peak kW: Secondary | 15.091 | /kW | All On-Peak kW: Secondary | 15.091 | /kW | - | /kW | 449. |
| 450. | | | | | All Excess Off-Peak kW: Secondary | 2.734 | /kW | All Off-Peak kW: Secondary | 2.734 | /kW | - | /kW | 450. |
| 451. | | | | | All On-Peak kW: Primary | 14.343 | /kW | All On-Peak kW: Primary | 14.343 | /kW | - | /kW | 451. |
| 452. | | | | | All Excess Off-Peak kW: Primary | 2.659 | /kW | All Off-Peak kW: Primary | 2.659 | /kW | - | /kW | 452. |
| 453. | | | | | All On-Peak kW: Primary on Military Bases | 11.520 | /kW | All On-Peak kW: Primary on Military Bases | 10.483 | /kW | (1.037) | /kW | 453. |
| 454. | | | | | All Excess Off-Peak kW; Primary on Military | 2.376 | /kW | All Off-Peak kW: Primary on Military Bases | 2.273 | /kW | (0.103) | /kW | 454. |
| 455. | | | | | All On-Peak kW: Trans. | 10.483 | /kW | All On-Peak kW: Transmission | 11.520 | /kW | 1.037 | /kW | 455. |
| 456. | | | | | All Excess Off-Peak kW: Trans. | 2.273 | /kW | All Off-Peak kW: Transmission | 2.376 | /kW | 0.103 | /kW | 456. |
| 457. | | | | | All On-Peak kWh | 0.04694 | /kWh | All On-Peak kWh | 0.04694 | /kWh | - | /kWh | 457. |
| 458. | | | | | All Off-Peak kWh | 0.03530 | /kWh | All Off-Peak kWh | 0.03530 | /kWh | - | /kWh | 458. |
| 459. | | | | | | | | | | | | | 459. |
| 460. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 1.183 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.525) | /day | 460. |
| 461. | | | | | BSC: Instrument-rated Meters | 1.795 | /day | BSC: Instrument-rated Meters | 1.328 | /day | (0.467) | /day | 461. |
| 462. | | | | | BSC: Primary Meters | 3.881 | /day | BSC: Primary Meters | 3.477 | /day | (0.404) | /day | 462. |
| 463. | | | | | BSC: Transmission Meters | 26.574 | /day | BSC: Transmission Meters | 26.855 | /day | 0.281 | /day | 463. |
| 464. | | | | | Demand Charge: Secondary | 15.091 | /kW | Demand Charge: Secondary | 15.091 | /kW | - | /kW | 464. |
| 465. | | | | | Demand Charge: Primary | 14.343 | /kW | Demand Charge: Primary | 14.343 | /kW | - | /kW | 465. |
| 466. | | | | | Demand Charge: Primary on Military Bases | 11.520 | /kW | Demand Charge: Primary on Military Bases | 10.483 | /kW | (1.037) | /kW | 466. |
| 467. | | | | | Demand Charge: Transmission | 10.483 | /kW | Demand Charge: Transmission | 11.520 | /kW | 1.037 | /kW | 467. |

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 1/01/2010.

Recap Schedules:
N/A

# ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 468. | | | | | | | | | | | | | 468. |
| 469. | E-36 XL | Station Use Service | Rate | Sum & Win | Basic Service Charge | $ 6,912.00 | /mo | Basic Service Charge | $ 6,912.00 | /mo | $ - | /mo | 469. |
| 470. | | | | | Metering Charge Company Owned | 1.29% | | Metering Charge Company Owned | 1.29% | | - | | 470. |
| 471. | | | | | Metering Charge Customer Owned | 0.35% | | Metering Charge Customer Owned | 0.35% | | - | | 471. |
| 472. | | | | | All kW: Secondary | 5.190 | /kW | All kW: Secondary | 3.605 | /kW | (1.585) | /kW | 472. |
| 473. | | | | | All kW: Primary | 5.008 | /kW | All kW: Primary | 3.423 | /kW | (1.585) | /kW | 473. |
| 474. | | | | | All kW: Transmission | 1.620 | /kW | All kW: Transmission | 0.035 | /kW | (1.585) | /kW | 474. |
| 475. | | | | | All kWh: Hourly Pricing Proxy plus | 0.00057 | /kWh | All kWh: Hourly Pricing Proxy plus | 0.00057 | /kWh | - | /kWh | 475. |
| 476. | | | | | | | | | | | | | 476. |
| 477. | E-36 M | Station Use Service Medium | Rate | Sum & win | PROPOSE NEW SCHEDULE | | | Billed on applicable E-32 rate except for BSC Charge | | | | | 477. |
| 478. | | | | | | | | BSC: Self-Contained Meters | $ 1.344 | /day | $ 1.344 | /day | 478. |
| 479. | | | | | | | | BSC: Instrument-rated Meters | 1.322 | /day | 1.322 | /day | 479. |
| 480. | | | | | | | | BSC: Primary Meters | 6.830 | /day | 6.830 | /day | 480. |
| 481. | | | | | | | | | | | | | 481. |
| 482. | | | | | | | | | | | | | 482. |
| 483. | E-40 | Agricultural Wind Machine Service | | Sum & Win | Service Charge $/HP | $ 0.049 | /HP-day | RATE E-40 PROPOSE TO CANCEL: CUSTOMER TO MOVE TO E-32 XS | | | | | 483. |
| 484. | | | | | All kWh | 0.09106 | /kWh | | | | | | 484. |
| 485. | | | | | | | | | | | | | 485. |
| 486. | E-47 | Dusk to Dawn Lighting Service | Rate | Sum & Win | FIXTURES (Company Owned) | | | FIXTURES (Company Owned) | | | | | 486. |
| 487. | | | | | A. Acorn 9,500 HPS | $ 27.06 | /mo | A. Acorn 9,500 HPS | $ 27.06 | /mo | $ - | /mo | 487. |
| 488. | | | | | Acorn 16,000 HPS | 30.04 | /mo | Acorn 16,000 HPS | 30.04 | /mo | - | /mo | 488. |
| 489. | | | | | B. Architectural 9,500 HPS | 15.38 | /mo | B. Architectural 9,500 HPS | 15.38 | /mo | - | /mo | 489. |
| 490. | | | | | Architectural 16,000 HPS | 17.96 | /mo | Architectural 16,000 HPS | 17.96 | /mo | - | /mo | 490. |
| 491. | | | | | Architectural 30,000 HPS | 21.31 | /mo | Architectural 30,000 HPS | 21.31 | /mo | - | /mo | 491. |
| 492. | | | | | Architectural 50,000 HPS | 26.29 | /mo | Architectural 50,000 HPS | 26.29 | /mo | - | /mo | 492. |
| 493. | | | | | Architectural 14,000 MH | 21.51 | /mo | Architectural 14,000 MH | 21.51 | /mo | - | /mo | 493. |
| 494. | | | | | Architectural 21,000 MH | 24.42 | /mo | Architectural 21,000 MH | 24.42 | /mo | - | /mo | 494. |
| 495. | | | | | Architectural 36,000 MH | 30.54 | /mo | Architectural 36,000 MH | 30.54 | /mo | - | /mo | 495. |
| 496. | | | | | Architectural 8,000 LPS | 22.35 | /mo | Architectural 8,000 LPS | 22.35 | /mo | - | /mo | 496. |
| 497. | | | | | Architectural 13,500 LPS | 26.36 | /mo | Architectural 13,500 LPS | 26.36 | /mo | - | /mo | 497. |
| 498. | | | | | Architectural 22,500 LPS | 30.11 | /mo | Architectural 22,500 LPS | 30.11 | /mo | - | /mo | 498. |
| 499. | | | | | Architectural 33,000 LPS | 36.22 | /mo | Architectural 33,000 LPS | 36.22 | /mo | - | /mo | 499. |
| 500. | | | | | C. Cobra/Roadway 5,800 HPS | 8.73 | /mo | C. Cobra/Roadway 5,800 HPS | 8.73 | /mo | - | /mo | 500. |
| 501. | | | | | Cobra/Roadway 9,500 HPS | 10.28 | /mo | Cobra/Roadway 9,500 HPS | 10.28 | /mo | - | /mo | 501. |
| 502. | | | | | Cobra/Roadway 16,000 HPS | 12.87 | /mo | Cobra/Roadway 16,000 HPS | 12.87 | /mo | - | /mo | 502. |
| 503. | | | | | Cobra/Roadway 30,000 HPS | 15.52 | /mo | Cobra/Roadway 30,000 HPS | 15.52 | /mo | - | /mo | 503. |
| 504. | | | | | Cobra/Roadway 50,000 HPS | 21.06 | /mo | Cobra/Roadway 50,000 HPS | 21.06 | /mo | - | /mo | 504. |
| 505. | | | | | Cobra/Roadway 14,000 MH | 14.97 | /mo | Cobra/Roadway 14,000 MH | 14.97 | /mo | - | /mo | 505. |
| 506. | | | | | Cobra/Roadway 21,000 MH | 17.49 | /mo | Cobra/Roadway 21,000 MH | 17.49 | /mo | - | /mo | 506. |
| 507. | | | | | Cobra/Roadway 36,000 MH | 23.03 | /mo | Cobra/Roadway 36,000 MH | 23.03 | /mo | - | /mo | 507. |
| 508. | | | | | Cobra/Roadway 8,000 FL | 17.20 | /mo | Cobra/Roadway 8,000 FL | 17.20 | /mo | - | /mo | 508. |
| 509. | | | | | D. Decorative Transit 9,500 HPS | 37.09 | /mo | D. Decorative Transit 9,500 HPS | 37.09 | /mo | - | /mo | 509. |
| 510. | | | | | Decorative Transit 16,000 HPS | 36.88 | /mo | Decorative Transit 16,000 HPS | 36.88 | /mo | - | /mo | 510. |
| 511. | | | | | Decorative Transit 30,000 HPS | 42.46 | /mo | Decorative Transit 30,000 HPS | 42.46 | /mo | - | /mo | 511. |
| 512. | | | | | E. Flood 30,000 HPS | 20.61 | /mo | E. Flood 30,000 HPS | 20.61 | /mo | - | /mo | 512. |
| 513. | | | | | Flood 50,000 HPS | 25.56 | /mo | Flood 50,000 HPS | 25.56 | /mo | - | /mo | 513. |
| 514. | | | | | Flood 21,000 MH | 22.00 | /mo | Flood 21,000 MH | 22.00 | /mo | - | /mo | 514. |
| 515. | | | | | Flood 36,000 MH | 26.82 | /mo | Flood 36,000 MH | 26.82 | /mo | - | /mo | 515. |
| 516. | | | | | F. Post Top gray 8,000 FL | 18.54 | /mo | F. Post Top gray 8,000 FL | 18.54 | /mo | - | /mo | 516. |
| 517. | | | | | Post Top gray 9,500 HPS | 10.60 | /mo | Post Top gray 9,500 HPS | 10.60 | /mo | - | /mo | 517. |
| 518. | | | | | Post Top black 9,500 HPS | 12.21 | /mo | Post Top black 9,500 HPS | 12.21 | /mo | - | /mo | 518. |
| 519. | | | | | Post Top Transit 9,500 HPS | 32.47 | /mo | Post Top Transit 9,500 HPS | 32.47 | /mo | - | /mo | 519. |
| 520. | | | | | G. FROZEN 4,000 INC | 9.78 | /mo | G. FROZEN 4,000 INC | 9.78 | /mo | - | /mo | 520. |
| 521. | | | | | FROZEN 7,000 MV | 12.67 | /mo | FROZEN 7,000 MV | 12.67 | /mo | - | /mo | 521. |
| 522. | | | | | FROZEN 20,000 MV | 24.92 | /mo | FROZEN 20,000 MV | 24.92 | /mo | - | /mo | 522. |
| 523. | | | | | FROZEN Brackets 8ft to 16ft | 1.72 | /mo | FROZEN Brackets 8ft to 16ft | 1.72 | /mo | - | /mo | 523. |
| 524. | | | | | FIXTURES (Customer Owned) | | | FIXTURES (Customer Owned) | | | | | 524. |
| 525. | | | | | A. Acorn 9,500 HPS | $ 9.22 | /mo | A. Acorn 9,500 HPS | $ 9.22 | /mo | $ - | /mo | 525. |
| 526. | | | | | Acorn 16,000 HPS | 11.65 | /mo | Acorn 16,000 HPS | 11.65 | /mo | - | /mo | 526. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 527. | | | | | | | | | | | | | 527. |
| 528. | E-47 | Dusk to Dawn Lighting | Rate | Sum & Win | FIXTURES (Customer Owned) (cont) | | | FIXTURES (Customer Owned) (cont) | | | | | 528. |
| 529. | (cont) | Service | | | B. Architectural 9,500 HPS | $ 7.34 | /mo | B. Architectural 9,500 HPS | $ 7.34 | /mo | - | /mo | 529. |
| 530. | | (cont) | | | Architectural 16,000 HPS | 9.82 | /mo | Architectural 16,000 HPS | 9.82 | /mo | - | /mo | 530. |
| 531. | | | | | Architectural 30,000 HPS | 12.60 | /mo | Architectural 30,000 HPS | 12.60 | /mo | - | /mo | 531. |
| 532. | | | | | Architectural 50,000 HPS | 18.13 | /mo | Architectural 50,000 HPS | 18.13 | /mo | - | /mo | 532. |
| 533. | | | | | Architectural 14,000 MH | 11.79 | /mo | Architectural 14,000 MH | 11.79 | /mo | - | /mo | 533. |
| 534. | | | | | Architectural 21,000 MH | 14.54 | /mo | Architectural 21,000 MH | 14.54 | /mo | - | /mo | 534. |
| 535. | | | | | Architectural 36,000 MH | 20.00 | /mo | Architectural 36,000 MH | 20.00 | /mo | - | /mo | 535. |
| 536. | | | | | Architectural 8,000 LPS | 9.82 | /mo | Architectural 8,000 LPS | 9.82 | /mo | - | /mo | 536. |
| 537. | | | | | Architectural 13,500 LPS | 11.84 | /mo | Architectural 13,500 LPS | 11.84 | /mo | - | /mo | 537. |
| 538. | | | | | Architectural 22,500 LPS | 14.45 | /mo | Architectural 22,500 LPS | 14.45 | /mo | - | /mo | 538. |
| 539. | | | | | Architectural 33,000 LPS | 17.02 | /mo | Architectural 33,000 LPS | 17.02 | /mo | - | /mo | 539. |
| 540. | | | | | C. Cobra/Roadway 5,800 HPS | 5.16 | /mo | C. Cobra/Roadway 5,800 HPS | 5.16 | /mo | - | /mo | 540. |
| 541. | | | | | Cobra/Roadway 9,500 HPS | 6.32 | /mo | Cobra/Roadway 9,500 HPS | 6.32 | /mo | - | /mo | 541. |
| 542. | | | | | Cobra/Roadway 16,000 HPS | 8.82 | /mo | Cobra/Roadway 16,000 HPS | 8.82 | /mo | - | /mo | 542. |
| 543. | | | | | Cobra/Roadway 30,000 HPS | 11.46 | /mo | Cobra/Roadway 30,000 HPS | 11.46 | /mo | - | /mo | 543. |
| 544. | | | | | Cobra/Roadway 50,000 HPS | 16.37 | /mo | Cobra/Roadway 50,000 HPS | 16.37 | /mo | - | /mo | 544. |
| 545. | | | | | Cobra/Roadway 14,000 MH | 10.20 | /mo | Cobra/Roadway 14,000 MH | 10.20 | /mo | - | /mo | 545. |
| 546. | | | | | Cobra/Roadway 21,000 MH | 12.69 | /mo | Cobra/Roadway 21,000 MH | 12.69 | /mo | - | /mo | 546. |
| 547. | | | | | Cobra/Roadway 36,000 MH | 17.63 | /mo | Cobra/Roadway 36,000 MH | 17.63 | /mo | - | /mo | 547. |
| 548. | | | | | Cobra/Roadway 8,000 FL | 5.04 | /mo | Cobra/Roadway 8,000 FL | 5.04 | /mo | - | /mo | 548. |
| 549. | | | | | D. Decorative Transit 9,500 HPS | 11.11 | /mo | D. Decorative Transit 9,500 HPS | 11.11 | /mo | - | /mo | 549. |
| 550. | | | | | Decorative Transit 16,000 HPS | 6.31 | /mo | *Decorative Transit 16,000 HPS* | 6.31 | /mo | - | /mo | 550. |
| 551. | | | | | Decorative Transit 30,000 HPS | 16.02 | /mo | Decorative Transit 30,000 HPS | 16.02 | /mo | - | /mo | 551. |
| 552. | | | | | E. Flood 30,000 HPS | 12.81 | /mo | E. Flood 30,000 HPS | 12.81 | /mo | - | /mo | 552. |
| 553. | | | | | Flood 50,000 HPS | 17.77 | /mo | Flood 50,000 HPS | 17.77 | /mo | - | /mo | 553. |
| 554. | | | | | Flood 21,000 MH | 13.53 | /mo | Flood 21,000 MH | 13.53 | /mo | - | /mo | 554. |
| 555. | | | | | Flood 36,000 MH | 18.35 | /mo | Flood 36,000 MH | 18.35 | /mo | - | /mo | 555. |
| 556. | | | | | F. Post Top gray 8,000 FL | 5.23 | /mo | F. Post Top gray 8,000 FL | 5.23 | /mo | - | /mo | 556. |
| 557. | | | | | Post Top gray 9,500 HPS | 6.65 | /mo | Post Top gray 9,500 HPS | 6.65 | /mo | - | /mo | 557. |
| 558. | | | | | Post Top black 9,500 HPS | 6.88 | /mo | Post Top black 9,500 HPS | 6.88 | /mo | - | /mo | 558. |
| 559. | | | | | Post Top Transit 9,500 HPS | 10.24 | /mo | Post Top Transit 9,500 HPS | 10.24 | /mo | - | /mo | 559. |
| 560. | | | | | G. FROZEN 4,000 INC | 5.47 | /mo | G. FROZEN 4,000 INC | 5.47 | /mo | - | /mo | 560. |
| 561. | | | | | FROZEN 7,000 MV | 7.27 | /mo | FROZEN 7,000 MV | 7.27 | /mo | - | /mo | 561. |
| 562. | | | | | FROZEN 20,000 MV | 14.12 | /mo | FROZEN 20,000 MV | 14.12 | /mo | - | /mo | 562. |
| 563. | | | | | POLES | | | POLES | | | | | 563. |
| 564. | | | | | A. Anchor Flush, Round, 1X, 12ft | $ 12.17 | /mo | A. Anchor Flush, Round, 1X, 12ft | $ 12.17 | /mo | $ - | /mo | 564. |
| 565. | | | | | Anchor Flush, Round, 1X, 22ft | 13.70 | /mo | Anchor Flush, Round, 1X, 22ft | 13.70 | /mo | - | /mo | 565. |
| 566. | | | | | Anchor Flush, Round, 1X, 25ft | 14.82 | /mo | Anchor Flush, Round, 1X, 25ft | 14.82 | /mo | - | /mo | 566. |
| 567. | | | | | Anchor Flush, Round, 1X, 30ft | 17.03 | /mo | Anchor Flush, Round, 1X, 30ft | 17.03 | /mo | - | /mo | 567. |
| 568. | | | | | Anchor Flush, Round, 1X, 32ft | 17.89 | /mo | Anchor Flush, Round, 1X, 32ft | 17.89 | /mo | - | /mo | 568. |
| 569. | | | | | Anchor Flush, Round, 2X, 12ft | 12.98 | /mo | Anchor Flush, Round, 2X, 12ft | 12.98 | /mo | - | /mo | 569. |
| 570. | | | | | Anchor Flush, Round, 2X, 22ft | 14.91 | /mo | Anchor Flush, Round, 2X, 22ft | 14.91 | /mo | - | /mo | 570. |
| 571. | | | | | Anchor Flush, Round, 2X, 25ft | 15.55 | /mo | Anchor Flush, Round, 2X, 25ft | 15.55 | /mo | - | /mo | 571. |
| 572. | | | | | Anchor Flush, Round, 2X, 30ft | 18.07 | /mo | Anchor Flush, Round, 2X, 30ft | 18.07 | /mo | - | /mo | 572. |
| 573. | | | | | Anchor Flush, Round, 2X, 32ft | 19.28 | /mo | Anchor Flush, Round, 2X, 32ft | 19.28 | /mo | - | /mo | 573. |
| 574. | | | | | Anchor Flush, Square, 5", 13ft | 13.95 | /mo | Anchor Flush, Square, 5", 13ft | 13.95 | /mo | - | /mo | 574. |
| 575. | | | | | Anchor Flush, Square, 5", 15ft | 12.47 | /mo | Anchor Flush, Square, 5", 15ft | 12.47 | /mo | - | /mo | 575. |
| 576. | | | | | Anchor Flush, Square, 5", 23ft | 14.79 | /mo | Anchor Flush, Square, 5", 23ft | 14.79 | /mo | - | /mo | 576. |
| 577. | | | | | Anchor Flush, Square, 5", 25ft | 16.26 | /mo | Anchor Flush, Square, 5", 25ft | 16.26 | /mo | - | /mo | 577. |
| 578. | | | | | Anchor Flush, Square, 5", 28ft | 18.05 | /mo | Anchor Flush, Square, 5", 28ft | 18.05 | /mo | - | /mo | 578. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 579. | | | | | | | | | | | | | 579. |
| 580. | E-47 | Dusk to Dawn Lighting | Rate | Sum & Win | POLES (cont) | | | POLES (cont) | | | | | 580. |
| 581. | (cont) | Service | | | A. Anchor Flush, Square, 5", 32ft | $ 17.95 | /mo | A. Anchor Flush, Square, 5", 32ft | $ 17.95 | /mo | $ - | /mo | 581. |
| 582. | | (cont) | | | Anchor Flush, Concrete, 12ft | 41.58 | /mo | Anchor Flush, Concrete, 12ft | 41.58 | /mo | - | /mo | 582. |
| 583. | | | | | Anchor Flush, Fiberglass, 12ft | 35.21 | /mo | Anchor Flush, Fiberglass, 12ft | 35.21 | /mo | - | /mo | 583. |
| 584. | | | | | Anchor Flush, Dec Transit Ped, 4", 16ft | 34.33 | /mo | Anchor Flush, Dec Transit Ped, 4", 16ft | 34.33 | /mo | - | /mo | 584. |
| 585. | | | | | Anchor Flush, Dec Transit, 6", 30ft | 66.28 | /mo | Anchor Flush, Dec Transit, 6", 30ft | 66.28 | /mo | - | /mo | 585. |
| 586. | | | | | B. Anchor Pedstl, Round, 1X, 12ft | 11.71 | /mo | B. Anchor Pedstl, Round, 1X, 12ft | 11.71 | /mo | - | /mo | 586. |
| 587. | | | | | Anchor Pedstl, Round, 1X, 22ft | 13.24 | /mo | Anchor Pedstl, Round, 1X, 22ft | 13.24 | /mo | - | /mo | 587. |
| 588. | | | | | Anchor Pedstl, Round, 1X, 25ft | 14.35 | /mo | Anchor Pedstl, Round, 1X, 25ft | 14.35 | /mo | - | /mo | 588. |
| 589. | | | | | Anchor Pedstl, Round, 1X, 30ft | 16.58 | /mo | Anchor Pedstl, Round, 1X, 30ft | 16.58 | /mo | - | /mo | 589. |
| 590. | | | | | Anchor Pedstl, Round, 1X, 32ft | 17.41 | /mo | Anchor Pedstl, Round, 1X, 32ft | 17.41 | /mo | - | /mo | 590. |
| 591. | | | | | Anchor Pedstl, Round, 2X, 12ft | 12.51 | /mo | Anchor Pedstl, Round, 2X, 12ft | 12.51 | /mo | - | /mo | 591. |
| 592. | | | | | Anchor Pedstl, Round, 2X, 22ft | 13.97 | /mo | Anchor Pedstl, Round, 2X, 22ft | 13.97 | /mo | - | /mo | 592. |
| 593. | | | | | Anchor Pedstl, Round, 2X, 25ft | 15.08 | /mo | Anchor Pedstl, Round, 2X, 25ft | 15.08 | /mo | - | /mo | 593. |
| 594. | | | | | Anchor Pedstl, Round, 2X, 30ft | 17.61 | /mo | Anchor Pedstl, Round, 2X, 30ft | 17.61 | /mo | - | /mo | 594. |
| 595. | | | | | Anchor Pedstl, Round, 2X, 32ft | 18.81 | /mo | Anchor Pedstl, Round, 2X, 32ft | 18.81 | /mo | - | /mo | 595. |
| 596. | | | | | Anchor Pedstl, Round, 3 Bolt, 32ft | 21.62 | /mo | Anchor Pedstl, Round, 3 Bolt, 32ft | 21.62 | /mo | - | /mo | 596. |
| 597. | | | | | Anchor Pedstl, Square, 5", 13ft | 13.50 | /mo | Anchor Pedstl, Square, 5", 13ft | 13.50 | /mo | - | /mo | 597. |
| 598. | | | | | Anchor Pedstl, Square, 5", 15ft | 13.80 | /mo | Anchor Pedstl, Square, 5", 15ft | 13.80 | /mo | - | /mo | 598. |
| 599. | | | | | Anchor Pedstl, Square, 5", 23ft | 14.32 | /mo | Anchor Pedstl, Square, 5", 23ft | 14.32 | /mo | - | /mo | 599. |
| 600. | | | | | Anchor Pedstl, Square, 5", 25ft | 15.80 | /mo | Anchor Pedstl, Square, 5", 25ft | 15.80 | /mo | - | /mo | 600. |
| 601. | | | | | Anchor Pedstl, Square, 5", 28ft | 17.56 | /mo | Anchor Pedstl, Square, 5", 28ft | 17.56 | /mo | - | /mo | 601. |
| 602. | | | | | Anchor Pedstl, Square, 5", 32ft | 18.23 | /mo | Anchor Pedstl, Square, 5", 32ft | 18.23 | /mo | - | /mo | 602. |
| 603. | | | | | C. Direct Bury, Round, 19ft | 18.42 | /mo | C. Direct Bury, Round, 19ft | 18.42 | /mo | - | /mo | 603. |
| 604. | | | | | Direct Bury, Round, 30ft | 14.38 | /mo | Direct Bury, Round, 30ft | 14.38 | /mo | - | /mo | 604. |
| 605. | | | | | Direct Bury, Round, 38ft | 17.55 | /mo | Direct Bury, Round, 38ft | 17.55 | /mo | - | /mo | 605. |
| 606. | | | | | Direct Bury, Self-Support, 40ft | 21.62 | /mo | Direct Bury, Self-Support, 40ft | 21.62 | /mo | - | /mo | 606. |
| 607. | | | | | Direct Bury, Stepped, 49ft | 64.99 | /mo | Direct Bury, Stepped, 49ft | 64.99 | /mo | - | /mo | 607. |
| 608. | | | | | Direct Bury, Square, 4", 34ft | 15.87 | /mo | Direct Bury, Square, 4", 34ft | 15.87 | /mo | - | /mo | 608. |
| 609. | | | | | Direct Bury, Square, 5", 20ft | 15.07 | /mo | Direct Bury, Square, 5", 20ft | 15.07 | /mo | - | /mo | 609. |
| 610. | | | | | Direct Bury, Square, 30ft | 15.71 | /mo | Direct Bury, Square, 30ft | 15.71 | /mo | - | /mo | 610. |
| 611. | | | | | Direct Bury, Square, 38ft | 17.05 | /mo | Direct Bury, Square, 38ft | 17.05 | /mo | - | /mo | 611. |
| 612. | | | | | Decorative Transit 41-6 | 20.47 | /mo | Decorative Transit 41-6 | 20.47 | /mo | - | /mo | 612. |
| 613. | | | | | Decorative Transit 47 | 25.50 | /mo | Decorative Transit 47 | 25.50 | /mo | - | /mo | 613. |
| 614. | | | | | Direct Bury, Steel Dist Pole, 35ft | 23.54 | /mo | Direct Bury, Steel Dist Pole, 35ft | 23.54 | /mo | - | /mo | 614. |
| 615. | | | | | D. Post Top, Dec Transit, 16ft | 35.07 | /mo | D. Post Top, Dec Transit, 16ft | 35.07 | /mo | - | /mo | 615. |
| 616. | | | | | Post Top, Gray Steel/Fiberglass, 23ft | 12.16 | /mo | Post Top, Gray Steel/Fiberglass, 23ft | 12.16 | /mo | - | /mo | 616. |
| 617. | | | | | Post Top, Black Steel, 23ft | 13.41 | /mo | Post Top, Black Steel, 23ft | 13.41 | /mo | - | /mo | 617. |
| 618. | | | | | E. FROZEN, Wood Poles, 30ft | 8.95 | /mo | E. FROZEN, Wood Poles, 30ft | 8.95 | /mo | - | /mo | 618. |
| 619. | | | | | FROZEN, Wood Poles, 35ft | 8.95 | /mo | FROZEN, Wood Poles, 35ft | 8.95 | /mo | - | /mo | 619. |
| 620. | | | | | FROZEN, Wood Poles, 40ft | 12.73 | /mo | FROZEN, Wood Poles, 40ft | 12.73 | /mo | - | /mo | 620. |
| 621. | | | | | ANCHOR BASE | | | ANCHOR BASE | | | | | 621. |
| 622. | | | | | Flush, 4ft | $ 9.91 | /mo | Flush, 4ft | $ 9.91 | /mo | $ - | /mo | 622. |
| 623. | | | | | Flush, 6ft | 11.82 | /mo | Flush, 6ft | 11.82 | /mo | - | /mo | 623. |
| 624. | | | | | Pedestal, 8ft | 13.54 | /mo | Pedestal, 8ft | 13.54 | /mo | - | /mo | 624. |
| 625. | | | | | Pedestal, 32' round steel pole, 4ft 6" | 9.39 | /mo | Pedestal, 32' round steel pole, 4ft 6" | 9.39 | /mo | - | /mo | 625. |
| 626. | | | | | OPTIONAL EQUIPMENT | | | OPTIONAL EQUIPMENT | | | | | 626. |
| 627. | | | | | 1. 100' OH, UG if conduit by customer | $ 3.50 | /mo | 1. 100' OH, UG if conduit by customer | $ 3.50 | /mo | $ - | /mo | 627. |
| 628. | | | | | 2. HPS not accessible by bucket | 2.80 | /mo | 2. HPS not accessible by bucket | 2.80 | /mo | - | /mo | 628. |
| 629. | | | | | 3. MH not accessible by bucket | 6.04 | /mo | 3. MH not accessible by bucket | 6.04 | /mo | - | /mo | 629. |
| 630. | | | | | NON-STANDARD FACILITIES | | | NON-STANDARD FACILITIES | $ - | | | | 630. |
| 631. | | | | | Service Charge | $ 3.35 | /mo | Service Charge | $ 3.35 | /mo | $ - | /mo | 631. |
| 632. | | | | | All kWh | 0.06345 | /kWh | All kWh | 0.06345 | /kWh | - | /kWh | 632. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) (G) | (H) | (I) (J) | (K) (L) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | Proposed Rates | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | Block | Rates | Change (I) - (F) | Line No. |
| 633 | | | | | | | | $ - | | 633. |
| 634. | E-53 | Electric Service for | Rate | Sum & Win | Billed on Rate Schedule E-32 or Rate Schedule E-32TOU | | | | | 634. |
| 635. | | Athletic Stadiums | | | | | | | | 635. |
| 636. | | and Sports Fields | Minimum | Sum & Win | No bills rendered when no usage | | | | | 636. |
| 637 | | | | | | | | $ - | | 637. |
| 638. | E-54 | Seasonal Service | Rate | Sum & Win | Billed on Rate Schedule E-32 or Rate Schedule E-32TOU | | | $ - | | 638. |
| 639. | | | | | | | | $ - | | 639. |
| 640 | | | Minimum | Sum & Win | "Floor" Annual Minimum | $ 603.49 /yr | "Floor" Annual Minimum | $ 603.49 /yr | $ - /yr | 640. |
| 641. | | | | | Monthly Minimum | 50.29 /mo | Monthly Minimum | 50.29 /mo | - /mo | 641. |
| 642. | | | | | | | | | | 642. |
| 643. | E-56 | Electric Service for | Basic | | | | | | | 643. |
| 644. | | Partial Requirements | Service | Sum & Win | Basic Service Charge | per applicable rate | Basic Service Charge | per applicable rate | | 644. |
| 645. | | Service for CG | | | | schedule | | schedule | | 645. |
| 646. | | installations of 100kw | | | | | | | | 646. |
| 647. | | | Supplemental | Sum & Win | All Supplemental Charges | per applicable rate | All Supplemental Charges | per applicable rate | | 647. |
| 648. | | | Service | | | schedule | | schedule | | 648. |
| 649. | | | | | | | | | | 649. |
| 650. | | | Back-Up | Sum & Win | Back-Up Service with E-32 On-Peak | 0.1184 /kW-day | Back-Up Service with E-32 On-Peak | 0.2760 /kW-day | 0.15760 /kW-day | 650. |
| 651. | | | Service | | Back-Up Service with E-32 Off-Peak | N/A | Back-Up Service with E-32 Off-Peak | N/A | - | 651. |
| 652. | | | | | Back-Up Service with E-34 On-Peak | 0.5756 /kW-day | Back-Up Service with E-34 On-Peak | 0.3500 /kW-day | (0.22560) /kW-day | 652. |
| 653. | | | | | Back-Up Service with E-34 Off-Peak | N/A | Back-Up Service with E-34 Off-Peak | N/A | - | 653. |
| 654. | | | | | | | | | | 654. |
| 655. | | | Maint. | Sum & Win | Scheduled Maintenance On-Peak | 1/2 Back-up Charge | Scheduled Maintenance On-Peak | 1/2 Back-up Charge | - | 655. |
| 656. | | | Service | | Scheduled Maintenance Off-Peak | N/A | Scheduled Maintenance Off-Peak | N/A | - | 656. |
| 657 | | | | | | | | | | 657. |
| 658. | | | Excess | Sum & Win | Secondary Service Excess Charge | $ 53.17 /kW | Secondary Service Excess Charge | $ 54.64 /kW | $ 1.47 /kW | 658. |
| 659. | | | | | Primary Service Excess Charge | 50.47 /kW | Primary Service Excess Charge | 51.87 /kW | 1.40 /kW | 659. |
| 660. | | | | | Transmission Service Excess Charge | 37.05 /kW | Transmission Service Excess Charge | 38.08 /kW | 1.03 /kW | 660. |
| 661. | | | | | | | | | | 661. |
| 662. | E-58 | Street Lighting Service | Rate | Sum & Win | FIXTURES (Investment by Company) | | FIXTURES (Investment by Company) | | | 662. |
| 663. | | | | | A. Acorn 9,500 HPS | $ 27.06 /mo | A. Acorn 9,500 HPS | $ 27.06 /mo | $ - /mo | 663. |
| 664 | | | | | Acorn 16,000 HPS | 30.04 /mo | Acorn 16,000 HPS | 30.04 /mo | - /mo | 664. |
| 665. | | | | | B. Architectural 9,500 HPS | 15.38 /mo | B. Architectural 9,500 HPS | 15.38 /mo | - /mo | 665. |
| 666. | | | | | Architectural 16,000 HPS | 17.96 /mo | Architectural 16,000 HPS | 17.96 /mo | - /mo | 666. |
| 667. | | | | | Architectural 30,000 HPS | 21.31 /mo | Architectural 30,000 HPS | 21.31 /mo | - /mo | 667. |
| 668. | | | | | Architectural 50,000 HPS | 26.29 /mo | Architectural 50,000 HPS | 26.29 /mo | - /mo | 668. |
| 669. | | | | | Architectural 14,000 MH | 21.51 /mo | Architectural 14,000 MH | 21.51 /mo | - /mo | 669. |
| 670. | | | | | Architectural 21,000 MH | 24.42 /mo | Architectural 21,000 MH | 24.42 /mo | - /mo | 670. |
| 671 | | | | | Architectural 36,000 MH | 30.54 /mo | Architectural 36,000 MH | 30.54 /mo | - /mo | 671. |
| 672. | | | | | Architectural 8,000 LPS | 22.35 /mo | Architectural 8,000 LPS | 22.35 /mo | - /mo | 672. |
| 673. | | | | | Architectural 13,500 LPS | 26.36 /mo | Architectural 13,500 LPS | 26.36 /mo | - /mo | 673. |
| 674. | | | | | Architectural 22,500 LPS | 30.11 /mo | Architectural 22,500 LPS | 30.11 /mo | - /mo | 674. |
| 675. | | | | | Architectural 33,000 LPS | 36.22 /mo | Architectural 33,000 LPS | 36.22 /mo | - /mo | 675. |
| 676. | | | | | C. Cobra/Roadway 5,800 HPS | 8.73 /mo | C. Cobra/Roadway 5,800 HPS | 8.73 /mo | - /mo | 676. |
| 677. | | | | | Cobra/Roadway 9,500 HPS | 10.28 /mo | Cobra/Roadway 9,500 HPS | 10.28 /mo | - /mo | 677. |
| 678. | | | | | Cobra/Roadway 16,000 HPS | 12.87 /mo | Cobra/Roadway 16,000 HPS | 12.87 /mo | - /mo | 678. |
| 679. | | | | | Cobra/Roadway 30,000 HPS | 15.52 /mo | Cobra/Roadway 30,000 HPS | 15.52 /mo | - /mo | 679. |
| 680. | | | | | Cobra/Roadway 50,000 HPS | 21.06 /mo | Cobra/Roadway 50,000 HPS | 21.06 /mo | - /mo | 680. |
| 681. | | | | | Cobra/Roadway 14,000 MH | 14.97 /mo | Cobra/Roadway 14,000 MH | 14.97 /mo | - /mo | 681. |
| 682 | | | | | Cobra/Roadway 21,000 MH | 17.49 /mo | Cobra/Roadway 21,000 MH | 17.49 /mo | - /mo | 682. |
| 683. | | | | | Cobra/Roadway 36,000 MH | 23.03 /mo | Cobra/Roadway 36,000 MH | 23.03 /mo | - /mo | 683. |
| 684. | | | | | Cobra/Roadway 8,000 FL | 17.20 /mo | Cobra/Roadway 8,000 FL | 17.20 /mo | - /mo | 684. |
| 685. | | | | | D. Decorative Transit 9,500 HPS | 37.09 /mo | D. Decorative Transit 9,500 HPS | 37.09 /mo | - /mo | 685. |
| 686. | | | | | Decorative Transit 16,000 HPS | 36.88 /mo | Decorative Transit 16,000 HPS | 36.88 /mo | - /mo | 686. |
| 687 | | | | | Decorative Transit 30,000 HPS | 42.46 /mo | Decorative Transit 30,000 HPS | 42.46 /mo | - /mo | 687. |
| 688. | | | | | E. Flood 30,000 HPS | 20.61 /mo | E. Flood 30,000 HPS | 20.61 /mo | - /mo | 688. |
| 689. | | | | | Flood 50,000 HPS | 25.56 /mo | Flood 50,000 HPS | 25.56 /mo | - /mo | 689. |
| 690. | | | | | Flood 21,000 MH | 22.00 /mo | Flood 21,000 MH | 22.00 /mo | - /mo | 690. |
| 691. | | | | | Flood 36,000 MH | 26.82 /mo | Flood 36,000 MH | 26.82 /mo | - /mo | 691. |
| 692. | | | | | F. Post Top gray 8,000 FL | 18.54 /mo | F. Post Top gray 8,000 FL | 18.54 /mo | - /mo | 692. |
| 693. | | | | | Post Top gray 9,500 HPS | 10.60 /mo | Post Top gray 9,500 HPS | 10.60 /mo | - /mo | 693. |
| 694. | | | | | Post Top black 9,500 HPS | 12.21 /mo | Post Top black 9,500 HPS | 12.21 /mo | - /mo | 694. |
| 695. | | | | | Post Top Transit 9,500 HPS | 32.47 /mo | Post Top Transit 9,500 HPS | 32.47 /mo | - /mo | 695. |
| 696. | | | | | G. FROZEN 4,000 INC | 9.78 /mo | G. FROZEN 4,000 INC | 9.78 /mo | - /mo | 696. |
| 697. | | | | | FROZEN 7,000 MV | 12.67 /mo | FROZEN 7,000 MV | 12.67 /mo | - /mo | 697. |
| 698. | | | | | FROZEN 11,000 MV | 15.87 /mo | FROZEN 11,000 MV | 15.87 /mo | - /mo | 698. |
| 699. | | | | | FROZEN 20,000 MV | 24.92 /mo | FROZEN 20,000 MV | 24.92 /mo | - /mo | 699. |

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 1/01/2010.

## ARIZONA PUBLIC SERVICE COMPANY

### CHANGES IN REPRESENTATIVE RATE SCHEDULES
### COMPARISON OF PRESENT AND RUCO PROPOSED RATES
### TEST YEAR ENDING DECEMBER 31, 2010

| Line No | (A) Rate Schedule | (B) Description | (C) Billing Designation | (D) Season | (E) Present Rates Block | (F) Present Rates Rates | (G) | (H) Proposed Rates Block | (I) Proposed Rates Rates | (J) | (K) Change (I) - (F) | (L) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 700. | | | | | | | | | | | | | 700. |
| 701. | E-58 | Street Lighting Service | Rate | Sum & Win | FIXTURES (Investment by Others) | | | FIXTURES (Investment by Others) | | | | | 701. |
| 702. | (cont) | | | | A. Acorn 9,500 HPS | $ 9.22 | /mo | A. Acorn 9,500 HPS | $ 9.22 | /mo | $ - | /mo | 702. |
| 703. | | | | | Acorn 16,000 HPS | 11.65 | /mo | Acorn 16,000 HPS | 11.65 | /mo | - | /mo | 703. |
| 704. | | | | | B. Architectural 9,500 HPS | 7.34 | /mo | B. Architectural 9,500 HPS | 7.34 | /mo | - | /mo | 704. |
| 705. | | | | | Architectural 16,000 HPS | 9.82 | /mo | Architectural 16,000 HPS | 9.82 | /mo | - | /mo | 705. |
| 706. | | | | | Architectural 30,000 HPS | 12.60 | /mo | Architectural 30,000 HPS | 12.60 | /mo | - | /mo | 706. |
| 707. | | | | | Architectural 50,000 HPS | 18.13 | /mo | Architectural 50,000 HPS | 18.13 | /mo | - | /mo | 707. |
| 708. | | | | | Architectural 14,000 MH | 11.79 | /mo | Architectural 14,000 MH | 11.79 | /mo | - | /mo | 708. |
| 709. | | | | | Architectural 21,000 MH | 14.54 | /mo | Architectural 21,000 MH | 14.54 | /mo | - | /mo | 709. |
| 710. | | | | | Architectural 36,000 MH | 20.00 | /mo | Architectural 36,000 MH | 20.00 | /mo | - | /mo | 710. |
| 711. | | | | | Architectural 8,000 LPS | 9.82 | /mo | Architectural 8,000 LPS | 9.82 | /mo | - | /mo | 711. |
| 712. | | | | | Architectural 13,500 LPS | 11.84 | /mo | B. Architectural 13,500 LPS | 11.84 | /mo | - | /mo | 712. |
| 713. | | | | | Architectural 22,500 LPS | 14.45 | /mo | Architectural 22,500 LPS | 14.45 | /mo | - | /mo | 713. |
| 714. | | | | | Architectural 33,000 LPS | 17.02 | /mo | Architectural 33,000 LPS | 17.02 | /mo | - | /mo | 714. |
| 715. | | | | | C. Cobra/Roadway 5,800 HPS | 5.16 | /mo | C. Cobra/Roadway 5,800 HPS | 5.16 | /mo | - | /mo | 715. |
| 716. | | | | | Cobra/Roadway 9,500 HPS | 6.32 | /mo | Cobra/Roadway 9,500 HPS | 6.32 | /mo | - | /mo | 716. |
| 717. | | | | | Cobra/Roadway 16,000 HPS | 8.82 | /mo | Cobra/Roadway 16,000 HPS | 8.82 | /mo | - | /mo | 717. |
| 718. | | | | | Cobra/Roadway 30,000 HPS | 11.46 | /mo | Cobra/Roadway 30,000 HPS | 11.46 | /mo | - | /mo | 718. |
| 719. | | | | | Cobra/Roadway 50,000 HPS | 16.37 | /mo | Cobra/Roadway 50,000 HPS | 16.37 | /mo | - | /mo | 719. |
| 720. | | | | | Cobra/Roadway 14,000 MH | 10.20 | /mo | Cobra/Roadway 14,000 MH | 10.20 | /mo | - | /mo | 720. |
| 721. | | | | | Cobra/Roadway 21,000 MH | 12.69 | /mo | Cobra/Roadway 21,000 MH | 12.69 | /mo | - | /mo | 721. |
| 722. | | | | | Cobra/Roadway 36,000 MH | 17.63 | /mo | Cobra/Roadway 36,000 MH | 17.63 | /mo | - | /mo | 722. |
| 723. | | | | | Cobra/Roadway 8,000 FL | 5.04 | /mo | Cobra/Roadway 8,000 FL | 5.04 | /mo | - | /mo | 723. |
| 724. | | | | | D. Decorative Transit 9,500 HPS | 11.11 | /mo | D. Decorative Transit 9,500 HPS | 11.11 | /mo | - | /mo | 724. |
| 725. | | | | | Decorative Transit 16,000 HPS | 12.41 | /mo | Decorative Transit 16,000 HPS | 12.41 | /mo | - | /mo | 725. |
| 726. | | | | | Decorative Transit 30,000 HPS | 16.02 | /mo | Decorative Transit 30,000 HPS | 16.02 | /mo | - | /mo | 726. |
| 727. | | | | | E. Flood 30,000 HPS | 12.81 | /mo | E. Flood 30,000 HPS | 12.81 | /mo | - | /mo | 727. |
| 728. | | | | | Flood 50,000 HPS | 17.77 | /mo | Flood 50,000 HPS | 17.77 | /mo | - | /mo | 728. |
| 729. | | | | | Flood 21,000 MH | 13.53 | /mo | Flood 21,000 MH | 13.53 | /mo | - | /mo | 729. |
| 730. | | | | | Flood 36,000 MH | 18.35 | /mo | Flood 36,000 MH | 18.35 | /mo | - | /mo | 730. |
| 731. | | | | | F. Post Top gray 8,000 FL | 5.23 | /mo | F. Post Top gray 8,000 FL | 5.23 | /mo | - | /mo | 731. |
| 732. | | | | | Post Top gray 9,500 HPS | 6.65 | /mo | Post Top gray 9,500 HPS | 6.65 | /mo | - | /mo | 732. |
| 733. | | | | | Post Top black 9,500 HPS | 6.88 | /mo | Post Top black 9,500 HPS | 6.88 | /mo | - | /mo | 733. |
| 734. | | | | | Post Top Transit 9,500 HPS | 10.24 | /mo | Post Top Transit 9,500 HPS | 10.24 | /mo | - | /mo | 734. |
| 735. | | | | | G. FROZEN 4,000 INC | 5.47 | /mo | G. FROZEN 4,000 INC | 5.47 | /mo | - | /mo | 735. |
| 736. | | | | | FROZEN 7,000 MV | 7.27 | /mo | FROZEN 7,000 MV | 7.27 | /mo | - | /mo | 736. |
| 737. | | | | | FROZEN 11,000 MV | 9.68 | /mo | FROZEN 11,000 MV | 9.68 | /mo | - | /mo | 737. |
| 738. | | | | | FROZEN 20,000 MV | 14.12 | /mo | FROZEN 20,000 MV | 14.12 | /mo | - | /mo | 738. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 739. | | | | | | | | | | | | | 739. |
| 740 | E-58 | Street Lighting Service | Rate | Sum & Win | POLES (Investment by Company) | | | POLES (Investment by Company) | | | | | 740. |
| 741 | (cont) | | | | A. Anchor Flush, Round, 1X, 12ft | $ 12.17 | /mo | A. Anchor Flush, Round, 1X, 12ft | $ 12.17 | /mo | $ - | /mo | 741. |
| 742. | | | | | Anchor Flush, Round, 1X, 22ft | 13.70 | /mo | Anchor Flush, Round, 1X, 22ft | 13.70 | /mo | - | /mo | 742. |
| 743. | | | | | Anchor Flush, Round, 1X, 25ft | 14.82 | /mo | Anchor Flush, Round, 1X, 25ft | 14.82 | /mo | - | /mo | 743. |
| 744. | | | | | Anchor Flush, Round, 1X, 30ft | 17.03 | /mo | Anchor Flush, Round, 1X, 30ft | 17.03 | /mo | - | /mo | 744. |
| 745. | | | | | Anchor Flush, Round, 1X, 32ft | 17.89 | /mo | Anchor Flush, Round, 1X, 32ft | 17.89 | /mo | - | /mo | 745. |
| 746. | | | | | Anchor Flush, Round, 2X, 12ft | 12.98 | /mo | Anchor Flush, Round, 2X, 12ft | 12.98 | /mo | - | /mo | 746. |
| 747. | | | | | Anchor Flush, Round, 2X, 22ft | 14.91 | /mo | Anchor Flush, Round, 2X, 22ft | 14.91 | /mo | - | /mo | 747. |
| 748. | | | | | Anchor Flush, Round, 2X, 25ft | 15.55 | /mo | Anchor Flush, Round, 2X, 25ft | 15.55 | /mo | - | /mo | 748. |
| 749. | | | | | Anchor Flush, Round, 2X, 30ft | 18.07 | /mo | Anchor Flush, Round, 2X, 30ft | 18.07 | /mo | - | /mo | 749. |
| 750. | | | | | Anchor Flush, Round, 2X, 32ft | 19.28 | /mo | Anchor Flush, Round, 2X, 32ft | 19.28 | /mo | - | /mo | 750. |
| 751. | | | | | Anchor Flush, Square, 5", 13ft | 13.95 | /mo | Anchor Flush, Square, 5", 13ft | 13.95 | /mo | - | /mo | 751. |
| 752. | | | | | Anchor Flush, Square, 5", 15ft | 12.47 | /mo | Anchor Flush, Square, 5", 15ft | 12.47 | /mo | - | /mo | 752. |
| 753. | | | | | Anchor Flush, Square, 5", 23ft | 14.79 | /mo | Anchor Flush, Square, 5", 23ft | 14.79 | /mo | - | /mo | 753. |
| 754. | | | | | Anchor Flush, Square, 5", 25ft | 16.26 | /mo | Anchor Flush, Square, 5", 25ft | 16.26 | /mo | - | /mo | 754. |
| 755. | | | | | Anchor Flush, Square, 5", 28ft | 18.05 | /mo | Anchor Flush, Square, 5", 28ft | 18.05 | /mo | - | /mo | 755. |
| 756. | | | | | Anchor Flush, Square, 5", 32ft | 17.95 | /mo | Anchor Flush, Square, 5", 32ft | 17.95 | /mo | - | /mo | 756. |
| 757 | | | | | Anchor Flush, Concrete, 12ft | 41.58 | /mo | Anchor Flush, Concrete, 12ft | 41.58 | /mo | - | /mo | 757. |
| 758. | | | | | Anchor Flush, Fiberglass, 12ft | 35.21 | /mo | Anchor Flush, Fiberglass, 12ft | 35.21 | /mo | - | /mo | 758. |
| 759 | | | | | Anchor Flush, Dec Transit Ped, 4", 16ft | 34.33 | /mo | Anchor Flush, Dec Transit Ped, 4", 16ft | 34.33 | /mo | - | /mo | 759. |
| 760 | | | | | Anchor Flush, Dec Transit, 6", 30ft | 66.28 | /mo | Anchor Flush, Dec Transit, 6", 30ft | 66.28 | /mo | - | /mo | 760. |
| 761. | | | | | B. Anchor Pedstl, Round, 1X, 12ft | 11.71 | /mo | B. Anchor Pedstl, Round, 1X, 12ft | 11.71 | /mo | - | /mo | 761. |
| 762 | | | | | Anchor Pedstl, Round, 1X, 22ft | 13.24 | /mo | Anchor Pedstl, Round, 1X, 22ft | 13.24 | /mo | - | /mo | 762. |
| 763 | | | | | Anchor Pedstl, Round, 1X, 25ft | 14.35 | /mo | Anchor Pedstl, Round, 1X, 25ft | 14.35 | /mo | - | /mo | 763. |
| 764 | | | | | Anchor Pedstl, Round, 1X, 30ft | 16.58 | /mo | Anchor Pedstl, Round, 1X, 30ft | 16.58 | /mo | - | /mo | 764. |
| 765. | | | | | Anchor Pedstl, Round, 1X, 32ft | 17.41 | /mo | Anchor Pedstl, Round, 1X, 32ft | 17.41 | /mo | - | /mo | 765. |
| 766. | | | | | Anchor Pedstl, Round, 2X, 12ft | 12.51 | /mo | Anchor Pedstl, Round, 2X, 12ft | 12.51 | /mo | - | /mo | 766. |
| 767. | | | | | Anchor Pedstl, Round, 2X, 22ft | 13.97 | /mo | Anchor Pedstl, Round, 2X, 22ft | 13.97 | /mo | - | /mo | 767. |
| 768. | | | | | Anchor Pedstl, Round, 2X, 25ft | 15.08 | /mo | Anchor Pedstl, Round, 2X, 25ft | 15.08 | /mo | - | /mo | 768. |
| 769. | | | | | Anchor Pedstl, Round, 2X, 30ft | 17.61 | /mo | Anchor Pedstl, Round, 2X, 30ft | 17.61 | /mo | - | /mo | 769. |
| 770 | | | | | Anchor Pedstl, Round, 2X, 32ft | 18.81 | /mo | Anchor Pedstl, Round, 2X, 32ft | 18.81 | /mo | - | /mo | 770. |
| 771. | | | | | Anchor Pedstl, Round, 3 Bolt, 32ft | 21.62 | /mo | Anchor Pedstl, Round, 3 Bolt, 32ft | 21.62 | /mo | - | /mo | 771. |
| 772. | | | | | Anchor Pedstl, Square, 5", 13ft | 13.50 | /mo | Anchor Pedstl, Square, 5", 13ft | 13.50 | /mo | - | /mo | 772. |
| 773. | | | | | Anchor Pedstl, Square, 5", 15ft | 13.80 | /mo | Anchor Pedstl, Square, 5", 15ft | 13.80 | /mo | - | /mo | 773. |
| 774. | | | | | Anchor Pedstl, Square, 5", 23ft | 14.32 | /mo | Anchor Pedstl, Square, 5", 23ft | 14.32 | /mo | - | /mo | 774. |
| 775. | | | | | Anchor Pedstl, Square, 5", 25ft | 15.80 | /mo | Anchor Pedstl, Square, 5", 25ft | 15.80 | /mo | - | /mo | 775. |
| 776. | | | | | Anchor Pedstl, Square, 5", 28ft | 17.56 | /mo | Anchor Pedstl, Square, 5", 28ft | 17.56 | /mo | - | /mo | 776. |
| 777. | | | | | Anchor Pedstl, Square, 5", 32ft | 18.23 | /mo | Anchor Pedstl, Square, 5", 32ft | 18.23 | /mo | - | /mo | 777. |
| 778. | | | | | C. Direct Bury, Round, 19ft | 18.42 | /mo | C. Direct Bury, Round, 19ft | 18.42 | /mo | - | /mo | 778. |
| 779. | | | | | Direct Bury, Round, 30ft | 14.38 | /mo | Direct Bury, Round, 30ft | 14.38 | /mo | - | /mo | 779. |
| 780. | | | | | Direct Bury, Round, 38ft | 17.55 | /mo | Direct Bury, Round, 38ft | 17.55 | /mo | - | /mo | 780. |
| 781. | | | | | Direct Bury, Self-Support, 40ft | 21.62 | /mo | Direct Bury, Self-Support, 40ft | 21.62 | /mo | - | /mo | 781. |
| 782. | | | | | Direct Bury, Stepped, 49ft | 64.99 | /mo | Direct Bury, Stepped, 49ft | 64.99 | /mo | - | /mo | 782. |
| 783 | | | | | Direct Bury, Square, 4", 34ft | 15.87 | /mo | Direct Bury, Square, 4", 34ft | 15.87 | /mo | - | /mo | 783. |
| 784. | | | | | Direct Bury, Square, 5", 20ft | 15.07 | /mo | Direct Bury, Square, 5", 20ft | 15.07 | /mo | - | /mo | 784. |
| 785. | | | | | Direct Bury, Square, 30ft | 15.71 | /mo | Direct Bury, Square, 30ft | 15.71 | /mo | - | /mo | 785. |
| 786. | | | | | Direct Bury, Square, 38ft | 17.05 | /mo | Direct Bury, Square, 38ft | 17.05 | /mo | - | /mo | 786. |
| 787. | | | | | Decorative Transit 41- 6 | 20.47 | /mo | Decorative Transit 41- 6 | 20.47 | /mo | - | /mo | 787. |
| 788 | | | | | Decorative Transit 47 | 25.50 | /mo | Decorative Transit 47 | 25.50 | /mo | - | /mo | 788. |
| 789 | | | | | Direct Bury, Steel Dist Pole, 35ft | 23.54 | /mo | Direct Bury, Steel Dist Pole, 35ft | 23.54 | /mo | - | /mo | 789. |

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 1/01/2010.

Recap Schedules:
N/A

## ARIZONA PUBLIC SERVICE COMPANY

### CHANGES IN REPRESENTATIVE RATE SCHEDULES
### COMPARISON OF PRESENT AND RUCO PROPOSED RATES

### TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 790. | | | | | | | | | | | | | 790. |
| 791. | E-58 | Street Lighting Service | Rate | Sum & Win | POLES (Investment by Company) (cont) | | | POLES (Investment by Company) (cont) | | | | | 791. |
| 792. | (cont) | | | | D. Post Top, Dec Transit, 16ft | $ 35.07 | /mo | D. Post Top, Dec Transit, 16ft | $ 35.07 | /mo | $ - | /mo | 792. |
| 793. | | | | | Post Top, Gray Steel/Fiberglass, 23ft | 12.16 | /mo | Post Top, Gray Steel/Fiberglass, 23ft | 12.16 | /mo | - | /mo | 793. |
| 794. | | | | | Post Top, Black Steel, 23ft | 13.41 | /mo | Post Top, Black Steel, 23ft | 13.41 | /mo | - | /mo | 794. |
| 795. | | | | | E. Existing Distribution Pole | 1.48 | /mo | E. Existing Distribution Pole | 1.48 | /mo | - | /mo | 795. |
| 796. | | | | | F. FROZEN, Wood Poles, 30ft | 8.95 | /mo | F. FROZEN, Wood Poles, 30ft | 8.95 | /mo | - | /mo | 796. |
| 797. | | | | | FROZEN, Wood Poles, 35ft | 8.95 | /mo | FROZEN, Wood Poles, 35ft | 8.95 | /mo | - | /mo | 797. |
| 798. | | | | | A. Anchor Flush, Round, 1X, 12ft | 1.68 | /mo | A. Anchor Flush, Round, 1X, 12ft | 1.68 | /mo | - | /mo | 798. |
| 799. | | | | | Anchor Flush, Round, 1X, 22ft | 1.88 | /mo | Anchor Flush, Round, 1X, 22ft | 1.88 | /mo | - | /mo | 799. |
| 800. | | | | | Anchor Flush, Round, 1X, 25ft | 2.05 | /mo | Anchor Flush, Round, 1X, 25ft | 2.05 | /mo | - | /mo | 800. |
| 801. | | | | | Anchor Flush, Round, 1X, 30ft | 2.34 | /mo | Anchor Flush, Round, 1X, 30ft | 2.34 | /mo | - | /mo | 801. |
| 802. | | | | | Anchor Flush, Round, 1X, 32ft | 2.37 | /mo | Anchor Flush, Round, 1X, 32ft | 2.37 | /mo | - | /mo | 802. |
| 803. | | | | | Anchor Flush, Round, 2X, 12ft | 1.79 | /mo | Anchor Flush, Round, 2X, 12ft | 1.79 | /mo | - | /mo | 803. |
| 804. | | | | | Anchor Flush, Round, 2X, 22ft | 2.06 | /mo | Anchor Flush, Round, 2X, 22ft | 2.06 | /mo | - | /mo | 804. |
| 805. | | | | | Anchor Flush, Round, 2X, 25ft | 2.14 | /mo | Anchor Flush, Round, 2X, 25ft | 2.14 | /mo | - | /mo | 805. |
| 806. | | | | | Anchor Flush, Round, 2X, 30ft | 2.49 | /mo | Anchor Flush, Round, 2X, 30ft | 2.49 | /mo | - | /mo | 806. |
| 807. | | | | | Anchor Flush, Round, 2X, 32ft | 2.66 | /mo | Anchor Flush, Round, 2X, 32ft | 2.66 | /mo | - | /mo | 807. |
| 808. | | | | | Anchor Flush, Square, 5", 13ft | 1.92 | /mo | Anchor Flush, Square, 5", 13ft | 1.92 | /mo | - | /mo | 808. |
| 809. | | | | | Anchor Flush, Square, 5", 15ft | 1.72 | /mo | Anchor Flush, Square, 5", 15ft | 1.72 | /mo | - | /mo | 809. |
| 810. | | | | | Anchor Flush, Square, 5", 23ft | 2.03 | /mo | Anchor Flush, Square, 5", 23ft | 2.03 | /mo | - | /mo | 810. |
| 811. | | | | | Anchor Flush, Square, 5", 25ft | 2.23 | /mo | Anchor Flush, Square, 5", 25ft | 2.23 | /mo | - | /mo | 811. |
| 812. | | | | | Anchor Flush, Square, 5", 28ft | 2.48 | /mo | Anchor Flush, Square, 5", 28ft | 2.48 | /mo | - | /mo | 812. |
| 813. | | | | | Anchor Flush, Square, 5", 32ft | 2.47 | /mo | Anchor Flush, Square, 5", 32ft | 2.47 | /mo | - | /mo | 813. |
| 814. | | | | | Anchor Flush, Concrete, 12ft | 5.73 | /mo | Anchor Flush, Concrete, 12ft | 5.73 | /mo | - | /mo | 814. |
| 815. | | | | | Anchor Flush, Fiberglass, 12ft | 4.85 | /mo | Anchor Flush, Fiberglass, 12ft | 4.85 | /mo | - | /mo | 815. |
| 816. | | | | | Anchor Flush, Dec Transit Ped, 4", 16ft | 4.73 | /mo | Anchor Flush, Dec Transit Ped, 4", 16ft | 4.73 | /mo | - | /mo | 816. |
| 817. | | | | | Anchor Flush, Dec Transit, 6", 30ft | 9.13 | /mo | Anchor Flush, Dec Transit, 6", 30ft | 9.13 | /mo | - | /mo | 817. |
| 818. | | | | | B. Anchor Pedstl, Round, 1X, 12ft | 1.61 | /mo | B. Anchor Pedstl, Round, 1X, 12ft | 1.61 | /mo | - | /mo | 818. |
| 819. | | | | | Anchor Pedstl, Round, 1X, 22ft | 1.82 | /mo | Anchor Pedstl, Round, 1X, 22ft | 1.82 | /mo | - | /mo | 819. |
| 820. | | | | | Anchor Pedstl, Round, 1X, 25ft | 1.98 | /mo | Anchor Pedstl, Round, 1X, 25ft | 1.98 | /mo | - | /mo | 820. |
| 821. | | | | | Anchor Pedstl, Round, 1X, 30ft | 2.29 | /mo | Anchor Pedstl, Round, 1X, 30ft | 2.29 | /mo | - | /mo | 821. |
| 822. | | | | | Anchor Pedstl, Round, 1X, 32ft | 2.40 | /mo | Anchor Pedstl, Round, 1X, 32ft | 2.40 | /mo | - | /mo | 822. |
| 823. | | | | | Anchor Pedstl, Round, 2X, 12ft | 1.72 | /mo | Anchor Pedstl, Round, 2X, 12ft | 1.72 | /mo | - | /mo | 823. |
| 824. | | | | | Anchor Pedstl, Round, 2X, 22ft | 1.92 | /mo | Anchor Pedstl, Round, 2X, 22ft | 1.92 | /mo | - | /mo | 824. |
| 825. | | | | | Anchor Pedstl, Round, 2X, 25ft | 2.07 | /mo | Anchor Pedstl, Round, 2X, 25ft | 2.07 | /mo | - | /mo | 825. |
| 826. | | | | | Anchor Pedstl, Round, 2X, 30ft | 2.42 | /mo | Anchor Pedstl, Round, 2X, 30ft | 2.42 | /mo | - | /mo | 826. |
| 827. | | | | | Anchor Pedstl, Round, 2X, 32ft | 2.59 | /mo | Anchor Pedstl, Round, 2X, 32ft | 2.59 | /mo | - | /mo | 827. |
| 828. | | | | | Anchor Pedstl, Round, 3 Bolt, 32ft | 2.97 | /mo | Anchor Pedstl, Round, 3 Bolt, 32ft | 2.97 | /mo | - | /mo | 828. |
| 829. | | | | | Anchor Pedstl, Square, 5", 13ft | 1.86 | /mo | Anchor Pedstl, Square, 5", 13ft | 1.86 | /mo | - | /mo | 829. |
| 830. | | | | | Anchor Pedstl, Square, 5", 15ft | 1.89 | /mo | Anchor Pedstl, Square, 5", 15ft | 1.89 | /mo | - | /mo | 830. |
| 831. | | | | | Anchor Pedstl, Square, 5", 23ft | 1.98 | /mo | Anchor Pedstl, Square, 5", 23ft | 1.98 | /mo | - | /mo | 831. |
| 832. | | | | | Anchor Pedstl, Square, 5", 25ft | 2.19 | /mo | Anchor Pedstl, Square, 5", 25ft | 2.19 | /mo | - | /mo | 832. |
| 833. | | | | | Anchor Pedstl, Square, 5", 28ft | 2.42 | /mo | Anchor Pedstl, Square, 5", 28ft | 2.42 | /mo | - | /mo | 833. |
| 834. | | | | | Anchor Pedstl, Square, 5", 32ft | 2.50 | /mo | Anchor Pedstl, Square, 5", 32ft | 2.50 | /mo | - | /mo | 834. |

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 1/01/2010.

Recap Schedules:
N/A

## ARIZONA PUBLIC SERVICE COMPANY

### CHANGES IN REPRESENTATIVE RATE SCHEDULES
### COMPARISON OF PRESENT AND RUCO PROPOSED RATES
### TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 835. | | | | | | | | | | | | | 835. |
| 836. | E-58 | Street Lighting Service | Rate | Sum & Win | POLES (Investment by Others) (cont) | | | POLES (Investment by Others) (cont) | | | | | 836. |
| 837. | (cont) | | | | C. Direct Bury, Round, 19ft | $ 2.54 | /mo | C. Direct Bury, Round, 19ft | $ 2.54 | /mo | $ - | /mo | 837. |
| 838. | | | | | Direct Bury, Round, 30ft | 2.66 | /mo | Direct Bury, Round, 30ft | 2.66 | /mo | - | /mo | 838. |
| 839. | | | | | Direct Bury, Round, 38ft | 2.73 | /mo | Direct Bury, Round, 38ft | 2.73 | /mo | - | /mo | 839. |
| 840. | | | | | Direct Bury, Self-Support, 40ft | 3.42 | /mo | Direct Bury, Self-Support, 40ft | 3.42 | /mo | - | /mo | 840. |
| 841. | | | | | Direct Bury, Stepped, 49ft | 8.96 | /mo | Direct Bury, Stepped, 49ft | 8.96 | /mo | - | /mo | 841. |
| 842. | | | | | Direct Bury, Square, 4", 34ft | 2.75 | /mo | Direct Bury, Square, 4", 34ft | 2.75 | /mo | - | /mo | 842. |
| 843. | | | | | Direct Bury, Square, 5", 20ft | 2.49 | /mo | Direct Bury, Square, 5", 20ft | 2.49 | /mo | - | /mo | 843. |
| 844. | | | | | Direct Bury, Square, 30ft | 2.59 | /mo | Direct Bury, Square, 30ft | 2.59 | /mo | - | /mo | 844. |
| 845. | | | | | Direct Bury, Square, 38ft | 2.96 | /mo | Direct Bury, Square, 38ft | 2.96 | /mo | - | /mo | 845. |
| 846. | | | | | Decorative Transit 41- 6 | 3.01 | /mo | Decorative Transit 41- 6 | 3.01 | /mo | - | /mo | 846. |
| 847. | | | | | Decorative Transit 47 | 3.75 | /mo | Decorative Transit 47 | 3.75 | /mo | - | /mo | 847. |
| 848. | | | | | Direct Bury, Steel Dist Pole, 35ft | 3.10 | /mo | Direct Bury, Steel Dist Pole, 35ft | 3.10 | /mo | - | /mo | 848. |
| 849. | | | | | D. Post Top, Dec Transit, 16ft | 4.82 | /mo | D. Post Top, Dec Transit, 16ft | 4.82 | /mo | - | /mo | 849. |
| 850. | | | | | Post Top, Gray Steel/Fiberglass, 23ft | 2.00 | /mo | Post Top, Gray Steel/Fiberglass, 23ft | 2.00 | /mo | - | /mo | 850. |
| 851 | | | | | Post Top, Black Steel, 23ft | 2.21 | /mo | Post Top, Black Steel, 23ft | 2.21 | /mo | - | /mo | 851. |
| 852. | | | | | E. Existing Distribution Pole | - | /mo | E. Existing Distribution Pole | - | /mo | - | /mo | 852. |
| 853. | | | | | F. FROZEN, Wood Poles, 30ft | 1.55 | /mo | F. FROZEN, Wood Poles, 30ft | 1.55 | /mo | - | /mo | 853. |
| 854. | | | | | FROZEN, Wood Poles, 35ft | 1.48 | /mo | FROZEN, Wood Poles, 35ft | 1.48 | /mo | - | /mo | 854. |
| 855. | | | | | ANCHOR BASE (Investment by Company) | | | ANCHOR BASE (Investment by Company) | | | | | 855. |
| 856 | | | | | Flush, 4ft | $ 9.91 | /mo | Flush, 4ft | $ 9.91 | /mo | $ - | /mo | 856. |
| 857 | | | | | Flush, 6ft | 11.82 | /mo | Flush, 6ft | 11.82 | /mo | - | /mo | 857. |
| 858. | | | | | Pedestal, 8ft | 13.54 | /mo | Pedestal, 8ft | 13.54 | /mo | - | /mo | 858. |
| 859. | | | | | Pedestal, 32' round steel pole, 4ft 6" | 9.39 | /mo | Pedestal, 32' round steel pole, 4ft 6" | 9.39 | /mo | - | /mo | 859. |
| 860 | | | | | ANCHOR BASE (Investment by Others) | | | ANCHOR BASE (Investment by Others) | | | | | 860. |
| 861. | | | | | Flush, 4ft | $ 1.36 | /mo | Flush, 4ft | $ 1.36 | /mo | $ - | /mo | 861. |
| 862 | | | | | Flush, 6ft | 2.05 | /mo | Flush, 6ft | 2.05 | /mo | - | /mo | 862. |
| 863. | | | | | Pedestal, 8ft | 2.36 | /mo | Pedestal, 8ft | 2.36 | /mo | - | /mo | 863. |
| 864. | | | | | Pedestal, 32' round steel pole, 4ft 6" | 1.63 | /mo | Pedestal, 32' round steel pole, 4ft 6" | 1.63 | /mo | - | /mo | 864. |
| 865 | | | | | OPTIONAL EQUIPMENT | | | OPTIONAL EQUIPMENT | 0.00 | | | | 865. |
| 866. | | | | | Per foot of cable under paving | $ 0.15716 | /mo | Per foot of cable under paving | 0.16 | /mo | - | /mo | 866. |
| 867. | | | | | Per foot of cable not under paving | 0.05589 | /mo | Per foot of cable not under paving | 0.06 | /mo | - | /mo | 867. |
| 868. | | | | | | | | | | | | | 868. |
| 869. | E-59 | Energy Services for Government | | Sum & Win | Service Charge | $ 2.79 | /mo | Service Charge | $ 2.79 | /mo | $ - | /mo | 869. |
| 870. | | Owned Streetlighting Systems | | | Energy Charge | 0.06088 | /kWh | Energy Charge | 0.06088 | /kWh | - | /kWh | 870. |
| 871. | | | | | | | | | | | | | 871. |
| 872. | E-67 | Municipal Lighting | Rate | Sum & Win | All kWh | $ 0.05193 | /kWh | All kWh | $ 0.05193 | /kWh | $ - | /kWh | 872. |
| 873. | | Service – City of Phoenix | | | | | | | | | | | 873. |

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 1/01/2010.

Recap Schedules:
N/A

## ARIZONA PUBLIC SERVICE COMPANY

### CHANGES IN REPRESENTATIVE RATE SCHEDULES
### COMPARISON OF PRESENT AND RUCO PROPOSED RATES
### TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 874. | | | | | | | | | | | | | 874. |
| 875. | E-114 | Share the Light | Rate | | Billed on Rate Schedule E-58 | | | RATE E-114 PROPOSE TO CANCEL | | | | | 875. |
| 876. | | | | | | | | | | | | | 876. |
| 877. | E-116 | Share the Light | Rate | | Billed on Rate Schedule E-58 | | | RATE E-116 PROPOSE TO CANCEL | | | | | 877. |
| 878. | | | | | | | | | | | | | 878. |
| 879. | E-145 | Share the Light | Rate | | Billed on Rate Schedule E-58 | | | RATE E-145 PROPOSE TO CANCEL | | | | | 879. |
| 880. | | | | | | | | | | | | | 880. |
| 881. | E-221 | Water Pumping Service | Rate | Sum & Win | Basic Service Charge | $ 0.558 | /day | Basic Service Charge | $ 0.588 | /day | $ 0.030 | /day | 881. |
| 882. | | | | | All kW | 1.880 | /kW | All kW | 1.867 | /kW | (0.013) | /kW | 882. |
| 883. | | | | | First 240 kWh | 0.11680 | /kWh | First 240 kWh | 0.11598 | /kWh | (0.00082) | /kWh | 883. |
| 884. | | | | | Next 275 kWh per kW | 0.07940 | /kWh | Next 275 kWh per kW | 0.07884 | /kWh | (0.00056) | /kWh | 884. |
| 885. | | | | | All additional kWh | 0.06519 | /kWh | All additional kWh | 0.06473 | /kWh | (0.00046) | /kWh | 885. |
| 886. | | | | | | | | | | | | | 886. |
| 887. | | Time of Week Option | | Sum & Win | Based on Measured kWh in Control Period: | | | RATE E-221 TIME OF WEEK OPTION PROPOSE TO CANCEL | | | | | 887. |
| 888. | | | | | 2 kWh per kW or less | $ (0.00785) | /kWh | | | | | | 888. |
| 889. | | | | | Greater than 8 kWh/kW | 0.00393 | /kWh | | | | | | 889. |
| 890. | | | | | | | | | | | | | 890. |
| 891. | | | Minimum | Sum & Win | Minimum Basic Service Charge | $ 0.558 | /day | Minimum Basic Service Charge | $ 0.554 | /day | $ (0.004) | /day | 891. |
| 892. | | | | | Minimum Demand Charge | 1.88 | /kW | Minimum Demand Charge | $ 1.867 | /kW | $ (0.013) | /kW | 892. |
| 893. | | | | | Minimum Annual kW Charge | 24.00 | /kW | Minimum Annual kW Charge | 24.00 | /kW | 0.000 | /kW | 893. |
| 894. | | | | | Minimum Annual Lump Sum Charge | 180.00 | - | Minimum Annual Lump Sum Charge | 180.00 | - | 0.000 | - | 894. |
| 895. | | | | | | | | | | | | | 895. |
| 896. | E-221-8T | Water Pumping Service | Rate | Sum & Win | Basic Service Charge | $ 0.964 | /day | Basic Service Charge | $ 1.015 | /day | $ 0.051 | /day | 896. |
| 897. | | Time Of Use | | | All On-Peak kW | 4.474 | /kW | All On-Peak kW | 4.443 | /kW | (0.031) | /kW | 897. |
| 898. | | | | | All Off-Peak kW | 2.673 | /kW | All Off-Peak kW | 2.654 | /kW | (0.019) | /kW | 898. |
| 899. | | | | | All On-Peak kWh | 0.09576 | /kWh | All On-Peak kWh | 0.09509 | /kWh | (0.00067) | /kWh | 899. |
| 900. | | | | | All Off-Peak kWh | 0.05151 | /kWh | All Off-Peak kWh | 0.05115 | /kWh | (0.00036) | /kWh | 900. |
| 901. | | | | | | | | | | | | | 901. |
| 902. | | | Minimum | Sum & Win | Minimum Basic Service Charge | $ 0.964 | /day | Minimum Basic Service Charge | $ 1.015 | /day | $ 0.051 | /day | 902. |
| 903. | | | | | Minimum Demand Charge | 2.673 | /kW | Minimum Demand Charge | 2.654 | /kW | (0.019) | /kW | 903. |
| 904. | | | | | Minimum Annual kW Charge | 34.20 | /kW | Minimum Annual kW Charge | 34.20 | /kW | - | /kW | 904. |
| 905. | | | | | Minimum Annual Lump Sum Charge | 310.44 | - | Minimum Annual Lump Sum Charge | 310.44 | - | - | - | 905. |
| 906. | | | | | | | | | | | | | 906. |
| 907. | E-249 | Share the Light | Rate | Sum & Win | Billed on Rate Schedule E-58 | | | RATE E-249 PROPOSE TO CANCEL | | | | | 907. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 908. | | | | | | | | | | | | | 908. |
| 909. | GS-SCHOOLS M | Time of Use for | Rate | Summer | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 909. |
| 910 | | Elementary and High Schools | | Peak | BSC: Instrument-rated Meters | 1.324 | /kW | BSC: Instrument-rated Meters | 1.324 | /kW | - | /kW | 910. |
| 911. | | 0-400 kW | | | BSC: Primary Meters | 3.415 | /kW | BSC: Primary Meters | 3.415 | /kW | - | /kW | 911. |
| 912. | | | | | BSC: Transmission Meters | 26.163 | /kW | BSC: Transmission Meters | 26.163 | /kW | - | /kW | 912. |
| 913. | | | | | First 100 kW: Secondary | 9.597 | /kW | First 100 kW: Secondary | 9.597 | /kW | - | /kW | 913. |
| 914. | | | | | All remaining kW: Secondary | 5.105 | /kW | All remaining kW: Secondary | 5.105 | /kW | - | /kW | 914. |
| 915. | | | | | First 100 kW: Primary | 8.905 | /kW | First 100 kW: Primary | 8.905 | /kW | - | /kW | 915. |
| 916. | | | | | All remaining kW: Primary | 4.412 | /kW | All remaining kW: Primary | 4.412 | /kW | - | /kW | 916. |
| 917. | | | | | First 100 kW: Transmission | 6.942 | /kW | First 100 kW: Transmission | 6.942 | /kW | - | /kW | 917. |
| 918. | | | | | All remaining kW: Transmission | 2.450 | /kW | All remaining kW: Transmission | 2.450 | /kW | - | /kW | 918. |
| 919. | | | | | All On-Peak kWh: | 0.17316 | /kWh | All On-Peak kWh: | 0.17316 | /kWh | - | /kWh | 919. |
| 920. | | | | | All Shoulder-Peak kWh: | 0.12827 | /kWh | All Shoulder-Peak kWh: | 0.12827 | /kWh | - | /kWh | 920. |
| 921. | | | | | All Off-Peak kWh: | 0.06477 | /kWh | All Off-Peak kWh: | 0.06477 | /kWh | - | /kWh | 921. |
| 922. | | | | | | | | | | | - | | 922. |
| 923. | GS-SCHOOLS M | | Rate | Summer | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 923. |
| 924. | (cont) | | | Shoulder | BSC: Instrument-rated Meters | 1.324 | /kW | BSC: Instrument-rated Meters | 1.324 | /kW | - | /kW | 924. |
| 925. | | | | | BSC: Primary Meters | 3.415 | /kW | BSC: Primary Meters | 3.415 | /kW | - | /kW | 925. |
| 926. | | | | | BSC: Transmission Meters | 26.163 | /kW | BSC: Transmission Meters | 26.163 | /kW | - | /kW | 926. |
| 927 | | | | | First 100 kW: Secondary | 9.597 | /kW | First 100 kW: Secondary | 9.597 | /kW | - | /kW | 927. |
| 928. | | | | | All remaining kW: Secondary | 5.105 | /kW | All remaining kW: Secondary | 5.105 | /kW | - | /kW | 928. |
| 929. | | | | | First 100 kW: Primary | 8.905 | /kW | First 100 kW: Primary | 8.905 | /kW | - | /kW | 929. |
| 930. | | | | | All remaining kW: Primary | 4.412 | /kW | All remaining kW: Primary | 4.412 | /kW | - | /kW | 930. |
| 931. | | | | | First 100 kW: Transmission | 6.942 | /kW | First 100 kW: Transmission | 6.942 | /kW | - | /kW | 931. |
| 932. | | | | | All remaining kW: Transmission | 2.450 | /kW | All remaining kW: Transmission | 2.450 | /kW | - | /kW | 932. |
| 933. | | | | | All On-Peak kWh: | 0.14953 | /kWh | All On-Peak kWh: | 0.14953 | /kWh | - | /kWh | 933. |
| 934. | | | | | All Shoulder-Peak kWh: | 0.11077 | /kWh | All Shoulder-Peak kWh: | 0.11077 | /kWh | - | /kWh | 934. |
| 935. | | | | | All Off-Peak kWh: | 0.05593 | /kWh | All Off-Peak kWh: | 0.05593 | /kWh | - | /kWh | 935. |
| 936. | | | | | | | | | | | | | 936. |
| 937 | | | Rate | Winter | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.014) | /day | 937. |
| 938 | | | | | BSC: Instrument-rated Meters | 1.324 | /kW | BSC: Instrument-rated Meters | 1.324 | /kW | - | /kW | 938. |
| 939. | | | | | BSC: Primary Meters | 3.415 | /kW | BSC: Primary Meters | 3.415 | /kW | - | /kW | 939. |
| 940 | | | | | BSC: Transmission Meters | 26.163 | /kW | BSC: Transmission Meters | 26.163 | /kW | - | /kW | 940. |
| 941 | | | | | First 100 kW: Secondary | 9.597 | /kW | First 100 kW: Secondary | 9.597 | /kW | - | /kW | 941. |
| 942. | | | | | All remaining kW: Secondary | 5.105 | /kW | All remaining kW: Secondary | 5.105 | /kW | - | /kW | 942. |
| 943. | | | | | First 100 kW: Primary | 8.905 | /kW | First 100 kW: Primary | 8.905 | /kW | - | /kW | 943. |
| 944. | | | | | All remaining kW: Primary | 4.412 | /kW | All remaining kW: Primary | 4.412 | /kW | - | /kW | 944. |
| 945. | | | | | First 100 kW: Transmission | 6.942 | /kW | First 100 kW: Transmission | 6.942 | /kW | - | /kW | 945. |
| 946. | | | | | All remaining kW: Transmission | 2.450 | /kW | All remaining kW: Transmission | 2.450 | /kW | - | /kW | 946. |
| 947. | | | | | All On-Peak kWh: | 0.11589 | /kWh | All On-Peak kWh: | 0.11589 | /kWh | - | /kWh | 947. |
| 948. | | | | | All Shoulder-Peak kWh: | 0.08585 | /kWh | All Shoulder-Peak kWh: | 0.08585 | /kWh | - | /kWh | 948. |
| 949. | | | | | All Off-Peak kWh: | 0.04335 | /kWh | All Off-Peak kWh: | 0.04335 | /kWh | - | /kWh | 949. |
| 950. | | | | | | | | | | | | | 950. |
| 951. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 0.672 | /day | BSC: Self-Contained Meters | $ 0.672 | /day | - | /day | 951. |
| 952. | | | | | BSC: Instrument-rated Meters | 1.324 | /day | BSC: Instrument-rated Meters | 1.324 | /day | - | /day | 952. |
| 953. | | | | | BSC: Primary Meters | 3.415 | /day | BSC: Primary Meters | 3.415 | /day | - | /day | 953. |
| 954. | | | | | BSC: Transmission Meters | 26.163 | /day | BSC: Transmission Meters | 26.163 | /day | - | /day | 954. |
| 955. | | | | | Minimum Demand Charge: | 2.189 | /kW | Minimum Demand Charge: | 2.189 | /kW | - | /kW | 955. |

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 1/01/2010.

Recap Schedules:
N/A

## ARIZONA PUBLIC SERVICE COMPANY
## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND RUCO PROPOSED RATES
## TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | | Line No. |
| 956. | | | | | | | | | | | | | 956. |
| 957. | GS-SCHOOLS L | Time of Use for | Rate | Summer | BSC: Self-Contained Meters | $ 1.068 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.410) | /day | 957. |
| 958. | | Elementary and High Schools | | Peak | BSC: Instrument-rated Meters | 1.627 | /kW | BSC: Instrument-rated Meters | 1.627 | /kW | - | /kW | 958. |
| 959. | | 401 kW and above | | | BSC: Primary Meters | 3.419 | /kW | BSC: Primary Meters | 3.419 | /kW | - | /kW | 959. |
| 960. | | | | | BSC: Transmission Meters | 22.915 | /kW | BSC: Transmission Meters | 22.915 | /kW | - | /kW | 960. |
| 961. | | | | | First 100 kW: Secondary | 9.384 | /kW | First 100 kW: Secondary | 9.384 | /kW | - | /kW | 961. |
| 962. | | | | | All remaining kW: Secondary | 4.993 | /kW | All remaining kW: Secondary | 4.993 | /kW | - | /kW | 962. |
| 963. | | | | | First 100 kW: Primary | 8.703 | /kW | First 100 kW: Primary | 8.703 | /kW | - | /kW | 963. |
| 964. | | | | | All remaining kW: Primary | 4.315 | /kW | All remaining kW: Primary | 4.315 | /kW | - | /kW | 964. |
| 965. | | | | | First 100 kW: Transmission | 6.788 | /kW | First 100 kW: Transmission | 6.788 | /kW | - | /kW | 965. |
| 966. | | | | | All remaining kW: Transmission | 2.396 | /kW | All remaining kW: Transmission | 2.396 | /kW | - | /kW | 966. |
| 967. | | | | | All On-Peak kWh: | 0.15475 | /kWh | All On-Peak kWh: | 0.15475 | /kWh | - | /kWh | 967. |
| 968. | | | | | All Shoulder-Peak kWh: | 0.11463 | /kWh | All Shoulder-Peak kWh: | 0.11463 | /kWh | - | /kWh | 968. |
| 969. | | | | | All Off-Peak kWh: | 0.06334 | /kWh | All Off-Peak kWh: | 0.06334 | /kWh | - | /kWh | 969. |
| 970. | | | | | | | | | | | | | 970. |
| 971. | GS-SCHOOLS L | | Rate | Summer | BSC: Self-Contained Meters | $ 1.068 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.410) | /day | 971. |
| 972. | (cont) | | | Shoulder | BSC: Instrument-rated Meters | 1.627 | /kW | BSC: Instrument-rated Meters | 1.627 | /kW | - | /kW | 972. |
| 973. | | | | | BSC: Primary Meters | 3.419 | /kW | BSC: Primary Meters | 3.419 | /kW | - | /kW | 973. |
| 974. | | | | | BSC: Transmission Meters | 22.915 | /kW | BSC: Transmission Meters | 22.915 | /kW | - | /kW | 974. |
| 975. | | | | | First 100 kW: Secondary | 9.384 | /kW | First 100 kW: Secondary | 9.384 | /kW | - | /kW | 975. |
| 976. | | | | | All remaining kW: Secondary | 4.993 | /kW | All remaining kW: Secondary | 4.993 | /kW | - | /kW | 976. |
| 977. | | | | | First 100 kW: Primary | 8.703 | /kW | First 100 kW: Primary | 8.703 | /kW | - | /kW | 977. |
| 978. | | | | | All remaining kW: Primary | 4.315 | /kW | All remaining kW: Primary | 4.315 | /kW | - | /kW | 978. |
| 979. | | | | | First 100 kW: Transmission | 6.788 | /kW | First 100 kW: Transmission | 6.788 | /kW | - | /kW | 979. |
| 980. | | | | | All remaining kW: Transmission | 2.396 | /kW | All remaining kW: Transmission | 2.396 | /kW | - | /kW | 980. |
| 981. | | | | | All On-Peak kWh: | 0.13363 | /kWh | All On-Peak kWh: | 0.13363 | /kWh | - | /kWh | 981. |
| 982. | | | | | All Shoulder-Peak kWh: | 0.09898 | /kWh | All Shoulder-Peak kWh: | 0.09898 | /kWh | - | /kWh | 982. |
| 983. | | | | | All Off-Peak kWh: | 0.05470 | /kWh | All Off-Peak kWh: | 0.05470 | /kWh | - | /kWh | 983. |
| 984. | | | | | | | | | | | | | 984. |
| 985. | | | Rate | Winter | BSC: Self-Contained Meters | $ 1.068 | /day | BSC: Self-Contained Meters | $ 0.658 | /day | $ (0.410) | /day | 985. |
| 986. | | | | | BSC: Instrument-rated Meters | 1.627 | /kW | BSC: Instrument-rated Meters | 1.627 | /kW | - | /kW | 986. |
| 987. | | | | | BSC: Primary Meters | 3.419 | /kW | BSC: Primary Meters | 3.419 | /kW | - | /kW | 987. |
| 988. | | | | | BSC: Transmission Meters | 22.915 | /kW | BSC: Transmission Meters | 22.915 | /kW | - | /kW | 988. |
| 989. | | | | | First 100 kW: Secondary | 9.384 | /kW | First 100 kW: Secondary | 9.384 | /kW | - | /kW | 989. |
| 990. | | | | | All remaining kW: Secondary | 4.993 | /kW | All remaining kW: Secondary | 4.993 | /kW | - | /kW | 990. |
| 991. | | | | | First 100 kW: Primary | 8.703 | /kW | First 100 kW: Primary | 8.703 | /kW | - | /kW | 991. |
| 992. | | | | | All remaining kW: Primary | 4.315 | /kW | All remaining kW: Primary | 4.315 | /kW | - | /kW | 992. |
| 993. | | | | | First 100 kW: Transmission | 6.788 | /kW | First 100 kW: Transmission | 6.788 | /kW | - | /kW | 993. |
| 994. | | | | | All remaining kW: Transmission | 2.396 | /kW | All remaining kW: Transmission | 2.396 | /kW | - | /kW | 994. |
| 995. | | | | | All On-Peak kWh: | 0.10356 | /kWh | All On-Peak kWh: | 0.10356 | /kWh | - | /kWh | 995. |
| 996. | | | | | All Shoulder-Peak kWh: | 0.07671 | /kWh | All Shoulder-Peak kWh: | 0.07671 | /kWh | - | /kWh | 996. |
| 997. | | | | | All Off-Peak kWh: | 0.04239 | /kWh | All Off-Peak kWh: | 0.04239 | /kWh | - | /kWh | 997. |
| 998. | | | | | | | | | | | | | 998. |
| 999. | | | Minimum | Sum & Win | BSC: Self-Contained Meters | $ 1.068 | /day | BSC: Self-Contained Meters | $ 1.068 | /day | - | /day | 999. |
| 1000. | | | | | BSC: Instrument-rated Meters | 1.627 | /day | BSC: Instrument-rated Meters | 1.627 | /day | - | /day | 1000. |
| 1001. | | | | | BSC: Primary Meters | 3.419 | /day | BSC: Primary Meters | 3.419 | /day | - | /day | 1001. |
| 1002. | | | | | BSC: Transmission Meters | 22.915 | /day | BSC: Transmission Meters | 22.915 | /day | - | /day | 1002. |
| 1003. | | | | | Minimum Demand Charge: | 2.115 | /kW | Minimum Demand Charge: | 2.115 | /kW | - | /kW | 1003. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) (G) | (H) | (I) (J) | (K) (L) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | Proposed Rates | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | Block | Rates | Change (I) - (F) | Line No. |
| 1004. | | | | | | | | | | 1004. |
| 1005. | CPP-GS | General Service | Rate | Summer | Critical Peak Price | $ 0.40000 /kWh | Critical Peak Price | $ 0.250000 /kWh | $ (0.150000) /kWh | 1005. |
| 1006. | | Critical Peak Pricing | | | | | | | | 1006. |
| 1007 | | | | | Energy Discount E-32 M | $ (0.014892) /kWh | Energy Discount E-32 M | $ (0.010351) /kWh | $ 0.004541 /kWh | 1007. |
| 1008. | | | | | Energy Discount E-32 L | (0.014438) /kWh | Energy Discount E-32 L | $ (0.009533) /kWh | $ 0.004905 /kWh | 1008. |
| 1009. | | | | | Energy Discount E-32 TOU M | (0.014892) /kWh | Energy Discount E-32 TOU M | $ (0.009266) /kWh | $ 0.005626 /kWh | 1009. |
| 1010. | | | | | Energy Discount E-32 TOU L | (0.014438) /kWh | Energy Discount E-32 TOU L | $ (0.008680) /kWh | $ 0.005758 /kWh | 1010. |
| 1011. | | | | | Energy Discount E-34 | (0.014350) /kWh | Energy Discount E-34 | $ (0.008519) /kWh | $ 0.005831 /kWh | 1011. |
| 1012. | | | | | Energy Discount E-35 | (0.012470) /kWh | Energy Discount E-35 | $ (0.007396) /kWh | $ 0.005074 /kWh | 1012. |
| 1013. | | | | | Energy Discount E-221 | (0.011755) /kWh | Energy Discount E-221 | $ (0.006116) /kWh | $ 0.005639 /kWh | 1013. |
| 1014. | | | | | | | | | | 1014. |
| 1015. | SC-S | Standard Contract - | Rate | Sum & Win | All kWh | Varies by Customer | All kWh | Varies by Customer | | 1015. |
| 1016. | | Solar | | | All kW | Varies by Customer | All kW | Varies by Customer | | 1016. |
| 1017. | | | | | | | | | | 1017. |
| 1018. | EPR-2 | Purchase Rates for Qualified | 9am - 9pm | Summer | Non-Firm On-Peak | $ 0.04236 /kWh | | | | 1018. |
| 1019. | | Facilities of 100 kW or less | Rate | | Non-Firm Off-Peak | 0.03734 /kWh | | | | 1019. |
| 1020. | | | | | Firm On-Peak | 0.05447 /kWh | | | | 1020. |
| 1021 | | | | | Firm Off-Peak | 0.03957 /kWh | | | | 1021. |
| 1022. | | | | | | | | | | 1022. |
| 1023. | | | | Winter | Non-Firm On-Peak | $ 0.03432 /kWh | | | | 1023. |
| 1024. | | | | | Non-Firm Off-Peak | 0.03622 /kWh | | | | 1024. |
| 1025. | | | | | Firm On-Peak | 0.03432 /kWh | | | | 1025. |
| 1026 | | | | | Firm Off-Peak | 0.03622 /kWh | | | | 1026. |
| 1027. | | | | | | | | | | 1027. |
| 1028. | EPR-2 | | 12pm - 7pm | Summer | Non-Firm On-Peak | $ 0.04473 /kWh | | | | 1028. |
| 1029. | (cont) | | Rate | | Non-Firm Off-Peak | 0.03766 /kWh | | | | 1029. |
| 1030. | | | | | Firm On-Peak | 0.06548 /kWh | | | | 1030. |
| 1031 | | | | | Firm Off-Peak | 0.03947 /kWh | | | | 1031. |
| 1032 | | | | | | | NO CHANGE | | | 1032. |
| 1033. | | | | Winter | Non-Firm On-Peak | $ 0.03224 /kWh | | | | 1033. |
| 1034 | | | | | Non-Firm Off-Peak | 0.03641 /kWh | | | | 1034. |
| 1035. | | | | | Firm On-Peak | 0.03224 /kWh | | | | 1035. |
| 1036. | | | | | Firm Off-Peak | 0.03641 /kWh | | | | 1036. |
| 1037. | | | | | | | | | | 1037. |
| 1038. | | | 11am - 9pm | Summer | Non-Firm On-Peak | $ 0.04405 /kWh | | | | 1038. |
| 1039. | | | Rate | | Non-Firm Off-Peak | 0.03705 /kWh | | | | 1039. |
| 1040. | | | | | Firm On-Peak | 0.05857 /kWh | | | | 1040. |
| 1041. | | | | | Firm Off-Peak | 0.03910 /kWh | | | | 1041. |
| 1042. | | | | | | | | | | 1042. |
| 1043. | | | | Winter | Non-Firm On-Peak | $ 0.03361 /kWh | | | | 1043. |
| 1044. | | | | | Non-Firm Off-Peak | 0.03636 /kWh | | | | 1044. |
| 1045. | | | | | Firm On-Peak | 0.03361 /kWh | | | | 1045. |
| 1046. | | | | | Firm Off-Peak | 0.03636 /kWh | | | | 1046. |
| 1047. | | | | | | | | | | 1047. |
| 1048. | EPR-6 | *Net Metering Rate* | Rate | Sum & Win | Energy Credit for Excess Generation | Credited Rates | Energy Credit for Excess Generation | Credited Rates | | 1048. |
| 1049. | | Renewable Resource Facilities | | | | Per Applicable | | Per Applicable | | 1049. |

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 1/01/2010.

Recap Schedules:
N/A

# ARIZONA PUBLIC SERVICE COMPANY

## CHANGES IN REPRESENTATIVE RATE SCHEDULES
## COMPARISON OF PRESENT AND RUCO PROPOSED RATES

### TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) (G) | (H) | (I) (J) | (K) (L) | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Rate Schedule | Description | Billing Designation | Season | Present Rates: Block | Present Rates: Rates | Proposed Rates: Block | Proposed Rates: Rates | Change (I) - (F) | Line No. |
| 1050. | | | | | | | | | | 1050. |
| 1051. | Solar-2 | Individual Solar | Initial Fee | Sum & Win | Up to $100,000 | 5% one time | | | | 1051. |
| 1052. | | Electric Service | | | More than $100,000 | 10% one time | | | | 1052. |
| 1053. | | | | | | | | | | 1053. |
| 1054 | | | Rate | Sum & Win | Service Fee: | | | | | 1054. |
| 1055. | | | | | Battery: None, sys size up to 2.5 kW | $ 5.00 /mo | | | | 1055. |
| 1056. | | | | | Battery: None, sys size over 2.5 kW | 5.00 /mo | | | | 1056. |
| 1057 | | | | | Battery: Sealed, sys size up to 2.5 kW | 45.00 /mo | | | | 1057. |
| 1058. | | | | | Battery: Sealed, sys size over 2.5 kW | 65.00 /mo | RATE SOLAR-2 PROPOSE TO CANCEL | | | 1058. |
| 1059 | | | | | Battery: Flooded, sys size up to 2.5 kW | 65.00 /mo | | | | 1059. |
| 1060. | | | | | Battery: Flooded, sys size over 2.5 kW | 85.00 /mo | | | | 1060. |
| 1061. | | | | | | | | | | 1061. |
| 1062. | | | | | Component Fee: | | | | | 1062. |
| 1063. | | | | | Long | 1.41% /mo | | | | 1063. |
| 1064. | | | | | Medium | 1.83% /mo | | | | 1064. |
| 1065. | | | | | Short | 2.75% /mo | | | | 1065. |
| 1066. | | | | | | | | | | 1066. |
| 1067 | Solar-3 | Solar Power Pilot Program | Rate | Sum & Win | Solar Power Premium | $ 0.16600 /kWh | RATE SOLAR-3 PROPOSE TO CANCEL | | | 1067. |
| 1068. | | | | | | | | | | 1068. |
| 1069. | SP-1 | Solar Partners | Rate | Sum & Win | RATE SP-1 CANCELED EFFECTIVE JANUARY 1, 2010 PER A.C.C. DECISION 69663 | | | | | 1069. |
| 1070. | | | | | AND A.C.C. DECISION 71448 | | | | | 1070. |
| 1071. | | | | | | | | | | 1071. |
| 1072. | CMPW-01 | Community Power | Rate | Sum & Win | Solar Charge E-12 | $ 0.11242 /kWh | | | | 1072. |
| 1073. | | Flagstaff SANDVIG 04 | | | Solar Charge ET-2 | 0.13480 /kWh | NO CHANGE | | | 1073. |
| 1074. | | | | | Solar Charge E-32 S, E-32 M, E-32 L | 0.09293 /kWh | | | | 1074. |
| 1075. | | | | | Solar Charge E-32 TOU S, E-32 TOU M, E-32 TOU L | 0.05855 /kWh | | | | 1075. |
| 1076. | | | | | | | | | | 1076. |
| 1077 | RSSP | Rural Schools Solar Program | Rate | Sum & Win | Solar Charge E-32 S, E-32 M, E-32 L | $ 0.09293 /kWh | | | | 1077. |
| 1078 | | | | | Solar Charge E-32 TOU S, E-32 TOU M, E-32 TOU L | 0.05855 /kWh | NO CHANGE | | | 1078. |
| 1079. | | | | | Solar Charge GS-SCHOOLS M, GS-SCHOOLS L | 0.07158 /kWh | | | | 1079. |
| 1080. | | | | | | | | | | 1080. |
| 1081. | AG-1 | Alternative Generation | Rate | Sum & Win | PROPOSE NEW SCHEDULE | | Billed on Rate Schedule E-34 or Rate Schedule E-35 | | | 1081. |
| 1082 | | Extra Large Service | | | | | Generation will be scheduled at market price plus uplift. | | | 1082. |

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 1/01/2010.

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND RUCO PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010

| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Present Rates | | | Proposed Rates | | | | |
| Line No. | Rate Schedule | Description | Billing Designation | Season | Block | Rates | | Block | Rates | | Change (I) - (F) | Line No. |
| 1083 | | | | | | | | | | | | 1083. |
| 1084 | DSMAC-1[1] | Demand Side Management | Adjustment | Sum & Win | all kWh | $ 0.001646 | /kWh | NO CHANGE | | | | 1084. |
| 1085. | | Adjustment Charge | | | all kW | 0.720083 | /kW | | | | | 1085. |
| 1086. | | | | | | | | | | | | 1086. |
| 1087. | CRCC-1[1] | Competition Rules | Adjustment | Sum & Win | ADJUSTMENT SCHEDULE CRCC-1 CANCELED EFFECTIVE OCTOBER 7, 2010 PER A.C.C. DECISION 67744 | | | | | | | 1087. |
| 1088. | | Compliance Charge | | | | | | | | | | 1088. |
| 1089. | | | | | | | | | | | | 1089. |
| 1090. | RCDAC-1[1] | Returning Customer Direct | Adjustment | Sum & Win | Customers over 3mW | varies by customer | | NO CHANGE | | | | 1090. |
| 1091. | | | | | | | | | | | | 1091. |
| 1092. | PSA-1[1,2] | Power Supply Adjustment | Adjustment | Sum & Win | PSA Adjustor | $ (0.005658) | /kWh | | | | | 1092. |
| 1093. | | | | | PSA Historical | (0.002642) | /kWh | NO CHANGE | | | | 1093. |
| 1094. | | | | | PSA Forward | (0.003016) | /kWh | | | | | 1094. |
| 1095. | | | | | PSA Transition | - | /kWh | | | | | 1095. |
| 1096. | | | | | | | | | | | | 1096. |
| 1097. | REAC-1[1] | Renewable Energy Standard | Adjustment | Sum & Win | All kWh | $ 0.010132 | /kWh | | | | | 1097. |
| 1098. | | | | | Cap for all Residential Services | 4.05 | /service | NO CHANGE | | | | 1098. |
| 1099. | | | | | Cap for General Services under 3MW | 150.53 | /service | | | | | 1099. |
| 1100. | | | | | Cap for General Services 3MW and above | 451.60 | /service | | | | | 1100. |
| 1101. | | | | | | | | | | | | 1101. |
| 1102. | EIS[1] | Environmental | Adjustment | Sum & Win | All kWh | $ 0.00016 | /kWh | ADJUSTMENT SCHEDULE EIS PROPOSE TO CANCEL | | | | 1102. |
| 1103. | | Improvement Surcharge | | | | | | | | | | 1103. |
| 1104. | | | | | | | | | | | | 1104. |
| 1105. | TCA-1[1,3] | Transmission | Adjustment | Sum & Win | All kW and kWh | | | | | | | 1105. |
| 1106. | | Cost | | | Residential - kWh | $ 0.002144 | /kWh | Residential - kWh | $ 0.002144 | /kWh | | 1106. |
| 1107. | | | | | General service 20 kW or less | 0.001602 | /kWh | General service 20 kW or less | 0.001602 | /kWh | | 1107. |
| 1108. | | | | | General service over 20 kW, under 3,000 kW | 0.740 | /kW | General service over 20 kW, under 3,000 kW | 0.740 | /kW | | 1108. |
| 1109. | | | | | XL General service 3,000 kW and over | 0.259 | /kW | XL General service 3,000 kW and over | 0.259 | /kW | | 1109. |
| 1110. | | | | | | | | | | | | 1110. |
| 1111. | GPS-1[1] | Green Power Block Schedule | Adjustment | Sum & Win | 100 kWh Block | $ 0.40000 | /kWh Block | NO CHANGE | | | | 1111. |
| 1112. | | | | | | | | | | | | 1112. |
| 1113. | GPS-2[1] | Green Power Percent Schedule | Adjustment | Sum & Win | 100.0% total monthly kWh | $ 0.00400 | /kWh | | | | | 1113. |
| 1114. | | | | | 50.0% total monthly kWh | 0.00200 | /kWh | NO CHANGE | | | | 1114. |
| 1115. | | | | | 35.0% total monthly kWh | 0.00140 | /kWh | | | | | 1115. |
| 1116. | | | | | 10.0% total monthly kWh | 0.00040 | /kWh | | | | | 1116. |
| 1117. | | | | | | | | | | | | 1117. |
| 1118. | GPS-3[1] | Green Power Block Schedule | Adjustment | Sum & Win | 100 kWh Block | $ 0.40000 | /kWh Block | NO CHANGE | | | | 1118. |
| 1119. | | for Special Events | | | Minimum purchase | 500.00 | /Transaction | | | | | 1119. |
| 1120. | | | | | | | | | | | | 1120. |
| 1121. | SDR | Self Directed Renewable | Adjustement | Sum & Win | Varies per customer | | | NO CHANGE | | | | 1121. |
| 1122. | | Resources | | | | | | | | | | 1122. |
| 1123. | | | | | | | | | | | | 1123. |
| 1124. | EIA-1[1] | Efficiency and Infrastructure Account | Adjustment | Sum & Win | PROPOSE NEW ADJUSTMENT SCHEDULE | | | % of customer's total monthly bill excluding taxes | | | | 1124. |
| 1125. | | | | | | | | and fees, and ERA-1 | | | | 1125. |
| 1126. | | | | | | | | | | | | 1126. |
| 1127. | ERA-1[1] | Environmental Reliability Account | Adjustment | Sum & Win | PROPOSE NEW ADJUSTMENT SCHEDULE | | | % of customer's total monthly bill excluding taxes | | | | 1127. |
| 1128. | | | | | | | | and fees, and EIA-1 | | | | 1128. |
| 1129. | | | | | | | | | | | | 1129. |

1130. [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. 1130.

1131. [2] Update to adjustment schedule PSA-1 approved by A.C.C. Decision No. 69663 per the PSA POA. 1131.

1132. 1132.

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 1/01/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| 0 | 8.55 | 9.41 | | 9.41 | 0.86 | 10.0% |
| 100 | 18.221 | 18.80 | | 18.80 | 0.58 | 3.2% |
| 200 | 27.34 | 28.20 | - | 28.20 | 0.86 | 3.1% |
| 250 | 32.04 | 32.90 | - | 32.90 | 0.86 | 2.7% |
| 300 | 36.74 | 37.60 | - | 37.60 | 0.86 | 2.3% |
| 350 | 41.44 | 42.29 | - | 42.29 | 0.85 | 2.1% |
| 400 | 46.14 | 46.99 | - | 46.99 | 0.85 | 1.8% |
| 450 | 50.84 | 51.69 | - | 51.69 | 0.85 | 1.7% |
| 500 | 55.54 | 56.39 | - | 56.39 | 0.85 | 1.5% |
| 550 | 60.23 | 61.09 | - | 61.09 | 0.86 | 1.4% |
| 600 | 64.93 | 65.79 | - | 65.79 | 0.86 | 1.3% |
| 650 | 69.63 | 70.49 | - | 70.49 | 0.86 | 1.2% |
| 700 | 74.33 | 75.18 | - | 75.18 | 0.85 | 1.1% |
| 750 | 79.03 | 79.88 | - | 79.88 | 0.85 | 1.1% |
| 800 | 83.73 | 84.58 | - | 84.58 | 0.85 | 1.0% |
| 850 | 88.42 | 89.28 | - | 89.28 | 0.86 | 1.0% |
| 900 | 93.12 | 93.98 | - | 93.98 | 0.86 | 0.9% |
| 950 | 97.82 | 98.68 | - | 98.68 | 0.86 | 0.9% |
| 1,000 | 102.52 | 103.38 | - | 103.38 | 0.86 | 0.8% |
| 1,100 | 111.92 | 112.77 | - | 112.77 | 0.85 | 0.8% |
| 1,200 | 121.31 | 122.17 | - | 122.17 | 0.86 | 0.7% |
| 1,300 | 130.71 | 131.57 | - | 131.57 | 0.86 | 0.7% |
| 1,400 | 140.11 | 140.96 | - | 140.96 | 0.85 | 0.6% |
| 1,500 | 149.51 | 150.36 | - | 150.36 | 0.85 | 0.6% |
| 1,600 | 158.90 | 159.76 | - | 159.76 | 0.86 | 0.5% |
| 1,700 | 168.30 | 169.15 | - | 169.15 | 0.85 | 0.5% |
| 1,800 | 177.70 | 178.55 | - | 178.55 | 0.85 | 0.5% |
| 1,900 | 187.09 | 187.95 | - | 187.95 | 0.86 | 0.5% |
| 2,000 | 196.49 | 197.35 | - | 197.35 | 0.85 | 0.4% |
| 2,200 | 215.28 | 216.14 | - | 216.14 | 0.86 | 0.4% |
| 2,400 | 234.08 | 234.93 | - | 234.93 | 0.85 | 0.4% |
| 2,600 | 252.87 | 253.73 | - | 253.73 | 0.86 | 0.3% |
| 2,800 | 271.67 | 272.52 | - | 272.52 | 0.85 | 0.3% |
| 3,000 | 290.46 | 291.32 | - | 291.32 | 0.85 | 0.3% |
| 4,000 | 384.43 | 385.29 | - | 385.29 | 0.85 | 0.2% |

Unbundled Transmission Charge: 0.00000 $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax ch
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly | under | | | under | | |
| kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| - | 8.55 | 9.41 | - | 9.41 | 0.86 | 10.0% |
| 100 | 18.22 | 19.08 | - | 19.08 | 0.85 | 4.7% |
| 200 | 27.89 | 28.75 | - | 28.75 | 0.86 | 3.1% |
| 300 | 37.56 | 38.42 | - | 38.42 | 0.86 | 2.3% |
| 400 | 47.23 | 48.09 | - | 48.09 | 0.86 | 1.8% |
| 450 | 54.10 | 54.50 | - | 54.50 | 0.40 | 0.7% |
| 500 | 60.97 | 60.92 | - | 60.92 | (0.05) | -0.1% |
| 550 | 67.84 | 67.33 | - | 67.33 | (0.51) | -0.8% |
| 600 | 74.71 | 73.74 | - | 73.74 | (0.97) | -1.3% |
| 650 | 81.58 | 80.16 | - | 80.16 | (1.42) | -1.7% |
| 700 | 88.45 | 86.57 | - | 86.57 | (1.88) | -2.1% |
| 750 | 95.32 | 92.99 | - | 92.99 | (2.33) | -2.4% |
| 800 | 102.19 | 99.40 | - | 99.40 | (2.79) | -2.7% |
| 850 | 110.33 | 107.54 | - | 107.54 | (2.79) | -2.5% |
| 900 | 118.47 | 115.68 | - | 115.68 | (2.79) | -2.4% |
| 950 | 126.61 | 123.82 | - | 123.82 | (2.79) | -2.2% |
| 1,000 | 134.75 | 131.96 | - | 131.96 | (2.79) | -2.1% |
| 1,100 | 151.03 | 148.24 | - | 148.24 | (2.79) | -1.8% |
| 1,200 | 167.31 | 164.52 | - | 164.52 | (2.79) | -1.7% |
| 1,300 | 183.60 | 180.80 | - | 180.80 | (2.80) | -1.5% |
| 1,400 | 199.88 | 197.09 | - | 197.09 | (2.79) | -1.4% |
| 1,500 | 216.16 | 213.37 | - | 213.37 | (2.79) | -1.3% |
| 1,600 | 232.44 | 229.65 | - | 229.65 | (2.79) | -1.2% |
| 1,700 | 248.72 | 245.93 | - | 245.93 | (2.79) | -1.1% |
| 1,800 | 265.00 | 262.21 | - | 262.21 | (2.79) | -1.1% |
| 1,900 | 281.28 | 278.49 | - | 278.49 | (2.79) | -1.0% |
| 2,000 | 297.56 | 294.77 | - | 294.77 | (2.79) | -0.9% |
| 2,200 | 330.12 | 327.33 | - | 327.33 | (2.79) | -0.8% |
| 2,400 | 362.69 | 359.90 | - | 359.90 | (2.79) | -0.8% |
| 2,600 | 395.25 | 392.46 | - | 392.46 | (2.79) | -0.7% |
| 2,800 | 427.81 | 425.02 | - | 425.02 | (2.79) | -0.7% |
| 3,000 | 460.37 | 457.58 | - | 457.58 | (2.79) | -0.6% |
| 4,000 | 633.95 | 639.84 | - | 639.84 | 5.89 | 0.9% |
| 5,000 | 807.53 | 822.10 | - | 822.10 | 14.57 | 1.8% |

Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax ch
2) *Present Rates are rates effective 1/1/2010.*

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly | under | | | under | | |
| kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| - | 16.68 | 18.36 | | 18.36 | 1.68 | 10.1% |
| 100 | 25.20 | 26.67 | | 26.67 | 1.47 | 5.8% |
| 200 | 33.72 | 34.97 | | 34.97 | 1.26 | 3.7% |
| 300 | 42.24 | 43.28 | | 43.28 | 1.05 | 2.5% |
| 400 | 50.75 | 51.59 | | 51.59 | 0.84 | 1.6% |
| 450 | 55.01 | 55.74 | | 55.74 | 0.73 | 1.3% |
| 500 | 59.27 | 59.90 | | 59.90 | 0.62 | 1.1% |
| 550 | 63.53 | 64.05 | | 64.05 | 0.52 | 0.8% |
| 600 | 67.79 | 68.20 | | 68.20 | 0.41 | 0.6% |
| 650 | 72.05 | 72.36 | | 72.36 | 0.31 | 0.4% |
| 700 | 76.31 | 76.51 | | 76.51 | 0.20 | 0.3% |
| 750 | 80.57 | 80.67 | | 80.67 | 0.10 | 0.1% |
| 800 | 84.83 | 84.82 | | 84.82 | (0.01) | 0.0% |
| 850 | 89.09 | 88.97 | | 88.97 | (0.11) | -0.1% |
| 900 | 93.35 | 93.13 | | 93.13 | (0.22) | -0.2% |
| 950 | 97.61 | 97.28 | | 97.28 | (0.32) | -0.3% |
| 1,000 | 101.87 | 101.43 | | 101.43 | (0.43) | -0.4% |
| 1,100 | 110.38 | 109.74 | | 109.74 | (0.64) | -0.6% |
| 1,200 | 118.90 | 118.05 | | 118.05 | (0.85) | -0.7% |
| 1,300 | 127.42 | 126.36 | | 126.36 | (1.06) | -0.8% |
| 1,400 | 135.94 | 134.66 | | 134.66 | (1.27) | -0.9% |
| 1,500 | 144.46 | 142.97 | | 142.97 | (1.49) | -1.0% |
| 1,600 | 152.98 | 151.28 | | 151.28 | (1.70) | -1.1% |
| 1,700 | 161.49 | 159.59 | | 159.59 | (1.91) | -1.2% |
| 1,800 | 170.01 | 167.89 | | 167.89 | (2.12) | -1.2% |
| 1,900 | 178.53 | 176.20 | | 176.20 | (2.33) | -1.3% |
| 2,000 | 187.05 | 184.51 | | 184.51 | (2.54) | -1.4% |
| 2,200 | 204.09 | 201.12 | | 201.12 | (2.96) | -1.5% |
| 2,400 | 221.12 | 217.74 | | 217.74 | (3.38) | -1.5% |
| 2,600 | 238.16 | 234.35 | | 234.35 | (3.81) | -1.6% |
| 2,800 | 255.20 | 250.97 | | 250.97 | (4.23) | -1.7% |
| 3,000 | 272.24 | 267.58 | | 267.58 | (4.65) | -1.7% |

ET-1 Winter Average Energy On-Peak: 33%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| - | 16.68 | 18.36 | | 18.36 | 1.68 | 10.1% |
| 100 | 27.41 | 29.02 | | 29.02 | 1.61 | 5.9% |
| 200 | 38.14 | 39.69 | | 39.69 | 1.54 | 4.0% |
| 300 | 48.88 | 50.35 | | 50.35 | 1.47 | 3.0% |
| 400 | 59.61 | 61.01 | | 61.01 | 1.41 | 2.4% |
| 450 | 64.97 | 66.34 | | 66.34 | 1.37 | 2.1% |
| 500 | 70.34 | 71.68 | | 71.68 | 1.34 | 1.9% |
| 550 | 75.70 | 77.01 | | 77.01 | 1.30 | 1.7% |
| 600 | 81.07 | 82.34 | | 82.34 | 1.27 | 1.6% |
| 650 | 86.44 | 87.67 | | 87.67 | 1.24 | 1.4% |
| 700 | 91.80 | 93.00 | | 93.00 | 1.20 | 1.3% |
| 750 | 97.17 | 98.33 | | 98.33 | 1.17 | 1.2% |
| 800 | 102.53 | 103.67 | | 103.67 | 1.13 | 1.1% |
| 850 | 107.90 | 109.00 | | 109.00 | 1.10 | 1.0% |
| 900 | 113.27 | 114.33 | | 114.33 | 1.06 | 0.9% |
| 950 | 118.63 | 119.66 | | 119.66 | 1.03 | 0.9% |
| 1,000 | 124.00 | 124.99 | | 124.99 | 1.00 | 0.8% |
| 1,100 | 134.73 | 135.66 | | 135.66 | 0.93 | 0.7% |
| 1,200 | 145.46 | 146.32 | | 146.32 | 0.86 | 0.6% |
| 1,300 | 156.19 | 156.98 | | 156.98 | 0.79 | 0.5% |
| 1,400 | 166.92 | 167.65 | | 167.65 | 0.72 | 0.4% |
| 1,500 | 177.66 | 178.31 | | 178.31 | 0.65 | 0.4% |
| 1,600 | 188.39 | 188.97 | | 188.97 | 0.59 | 0.3% |
| 1,700 | 199.12 | 199.64 | | 199.64 | 0.52 | 0.3% |
| 1,800 | 209.85 | 210.30 | | 210.30 | 0.45 | 0.2% |
| 1,900 | 220.58 | 220.96 | | 220.96 | 0.38 | 0.2% |
| 2,000 | 231.31 | 231.63 | | 231.63 | 0.31 | 0.1% |
| 2,200 | 252.78 | 252.95 | | 252.95 | 0.18 | 0.1% |
| 2,400 | 274.24 | 274.28 | | 274.28 | 0.04 | 0.0% |
| 2,600 | 295.70 | 295.61 | | 295.61 | (0.10) | 0.0% |
| 2,800 | 317.17 | 316.93 | | 316.93 | (0.24) | -0.1% |
| 3,000 | 338.63 | 338.26 | | 338.26 | (0.37) | -0.1% |

ET-1 Summer Average Energy On-Peak: 41%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly | under | | | under | | |
| kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| - | 16.68 | 18.35 | - | 18.35 | 1.67 | 10.0% |
| 100 | 25.13 | 26.54 | - | 26.54 | 1.41 | 5.6% |
| 200 | 33.59 | 34.73 | - | 34.73 | 1.15 | 3.4% |
| 300 | 42.04 | 42.93 | - | 42.93 | 0.89 | 2.1% |
| 400 | 50.49 | 51.12 | - | 51.12 | 0.63 | 1.2% |
| 450 | 54.72 | 55.22 | - | 55.22 | 0.50 | 0.9% |
| 500 | 58.95 | 59.31 | - | 59.31 | 0.37 | 0.6% |
| 550 | 63.17 | 63.41 | - | 63.41 | 0.24 | 0.4% |
| 600 | 67.40 | 67.51 | - | 67.51 | 0.11 | 0.2% |
| 650 | 71.63 | 71.60 | - | 71.60 | (0.02) | 0.0% |
| 700 | 75.85 | 75.70 | - | 75.70 | (0.15) | -0.2% |
| 750 | 80.08 | 79.80 | - | 79.80 | (0.28) | -0.4% |
| 800 | 84.31 | 83.89 | - | 83.89 | (0.41) | -0.5% |
| 850 | 88.53 | 87.99 | - | 87.99 | (0.54) | -0.6% |
| 900 | 92.76 | 92.09 | - | 92.09 | (0.67) | -0.7% |
| 950 | 96.99 | 96.18 | - | 96.18 | (0.80) | -0.8% |
| 1,000 | 101.21 | 100.28 | - | 100.28 | (0.93) | -0.9% |
| 1,100 | 109.66 | 108.47 | - | 108.47 | (1.19) | -1.1% |
| 1,200 | 118.12 | 116.67 | - | 116.67 | (1.45) | -1.2% |
| 1,300 | 126.57 | 124.86 | - | 124.86 | (1.71) | -1.4% |
| 1,400 | 135.02 | 133.05 | - | 133.05 | (1.97) | -1.5% |
| 1,500 | 143.48 | 141.25 | - | 141.25 | (2.23) | -1.6% |
| 1,600 | 151.93 | 149.44 | - | 149.44 | (2.49) | -1.6% |
| 1,700 | 160.38 | 157.63 | - | 157.63 | (2.75) | -1.7% |
| 1,800 | 168.84 | 165.83 | - | 165.83 | (3.01) | -1.8% |
| 1,900 | 177.29 | 174.02 | - | 174.02 | (3.27) | -1.8% |
| 2,000 | 185.74 | 182.21 | - | 182.21 | (3.53) | -1.9% |
| 2,200 | 202.65 | 198.60 | - | 198.60 | (4.05) | -2.0% |
| 2,400 | 219.56 | 214.99 | - | 214.99 | (4.57) | -2.1% |
| 2,600 | 236.46 | 231.37 | - | 231.37 | (5.09) | -2.2% |
| 2,800 | 253.37 | 247.76 | - | 247.76 | (5.61) | -2.2% |
| 3,000 | 270.28 | 264.15 | - | 264.15 | (6.13) | -2.3% |

ET-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly | under | | | under | | |
| kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| - | 16.68 | 18.35 | | 18.35 | 1.67 | 10.0% |
| 100 | 29.22 | 30.98 | | 30.98 | 1.76 | 6.0% |
| 200 | 41.76 | 43.61 | | 43.61 | 1.85 | 4.4% |
| 300 | 54.29 | 56.24 | | 56.24 | 1.94 | 3.6% |
| 400 | 66.83 | 68.87 | | 68.87 | 2.04 | 3.0% |
| 450 | 73.10 | 75.18 | | 75.18 | 2.08 | 2.8% |
| 500 | 79.37 | 81.50 | | 81.50 | 2.13 | 2.7% |
| 550 | 85.64 | 87.81 | | 87.81 | 2.17 | 2.5% |
| 600 | 91.91 | 94.13 | | 94.13 | 2.22 | 2.4% |
| 650 | 98.17 | 100.44 | | 100.44 | 2.27 | 2.3% |
| 700 | 104.44 | 106.76 | | 106.76 | 2.31 | 2.2% |
| 750 | 110.71 | 113.07 | | 113.07 | 2.36 | 2.1% |
| 800 | 116.98 | 119.39 | | 119.39 | 2.40 | 2.1% |
| 850 | 123.25 | 125.70 | | 125.70 | 2.45 | 2.0% |
| 900 | 129.52 | 132.02 | | 132.02 | 2.50 | 1.9% |
| 950 | 135.79 | 138.33 | | 138.33 | 2.54 | 1.9% |
| 1,000 | 142.06 | 144.64 | | 144.64 | 2.59 | 1.8% |
| 1,100 | 154.59 | 157.27 | | 157.27 | 2.68 | 1.7% |
| 1,200 | 167.13 | 169.90 | | 169.90 | 2.77 | 1.7% |
| 1,300 | 179.67 | 182.53 | | 182.53 | 2.86 | 1.6% |
| 1,400 | 192.21 | 195.16 | | 195.16 | 2.96 | 1.5% |
| 1,500 | 204.74 | 207.79 | | 207.79 | 3.05 | 1.5% |
| 1,600 | 217.28 | 220.42 | | 220.42 | 3.14 | 1.4% |
| 1,700 | 229.82 | 233.05 | | 233.05 | 3.23 | 1.4% |
| 1,800 | 242.36 | 245.68 | | 245.68 | 3.32 | 1.4% |
| 1,900 | 254.90 | 258.31 | | 258.31 | 3.42 | 1.3% |
| 2,000 | 267.43 | 270.94 | | 270.94 | 3.51 | 1.3% |
| 2,200 | 292.51 | 296.20 | | 296.20 | 3.69 | 1.3% |
| 2,400 | 317.58 | 321.46 | | 321.46 | 3.88 | 1.2% |
| 2,600 | 342.66 | 346.72 | | 346.72 | 4.06 | 1.2% |
| 2,800 | 367.73 | 371.98 | | 371.98 | 4.24 | 1.2% |
| 3,000 | 392.81 | 397.24 | | 397.24 | 4.43 | 1.1% |

ET-2 Summer Average Energy On-Peak: 35%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | |
| | Load | Monthly | under | | | under | | |
| kW | Factor | kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 3 | 20% | 438 | 65.17 | 67.26 | | 67.26 | 2.09 | 3.2% |
| 3 | 30% | 657 | 75.60 | 77.22 | | 77.22 | 1.61 | 2.1% |
| 3 | 40% | 876 | 86.04 | 87.18 | | 87.18 | 1.13 | 1.3% |
| 3 | 50% | 1,095 | 96.48 | 97.13 | | 97.13 | 0.65 | 0.7% |
| 3 | 75% | 1,643 | 122.60 | 122.06 | | 122.06 | (0.55) | -0.4% |
| 5 | 20% | 730 | 97.49 | 99.86 | | 99.86 | 2.37 | 2.4% |
| 5 | 30% | 1,095 | 114.89 | 116.46 | | 116.46 | 1.57 | 1.4% |
| 5 | 40% | 1,460 | 132.29 | 133.06 | | 133.06 | 0.78 | 0.6% |
| 5 | 50% | 1,825 | 149.68 | 149.66 | | 149.66 | (0.02) | 0.0% |
| 5 | 75% | 2,738 | 193.20 | 191.18 | | 191.18 | (2.02) | -1.0% |
| 8 | 20% | 1,168 | 145.98 | 148.77 | | 148.77 | 2.79 | 1.9% |
| 8 | 30% | 1,752 | 173.81 | 175.33 | | 175.33 | 1.52 | 0.9% |
| 8 | 40% | 2,336 | 201.65 | 201.89 | | 201.89 | 0.24 | 0.1% |
| 8 | 50% | 2,920 | 229.48 | 228.45 | | 228.45 | (1.04) | -0.5% |
| 8 | 75% | 4,380 | 299.07 | 294.84 | | 294.84 | (4.23) | -1.4% |
| 10 | 20% | 1,460 | 178.30 | 181.38 | | 181.38 | 3.08 | 1.7% |
| 10 | 30% | 2,190 | 213.10 | 214.57 | | 214.57 | 1.48 | 0.7% |
| 10 | 40% | 2,920 | 247.89 | 247.77 | | 247.77 | (0.12) | 0.0% |
| 10 | 50% | 3,650 | 282.69 | 280.97 | | 280.97 | (1.71) | -0.6% |
| 10 | 75% | 5,475 | 369.67 | 363.97 | | 363.97 | (5.71) | -1.5% |
| 12 | 20% | 1,752 | 210.62 | 213.98 | | 213.98 | 3.36 | 1.6% |
| 12 | 30% | 2,628 | 252.38 | 253.82 | | 253.82 | 1.44 | 0.6% |
| 12 | 40% | 3,504 | 294.13 | 293.66 | | 293.66 | (0.47) | -0.2% |
| 12 | 50% | 4,380 | 335.89 | 333.50 | | 333.50 | (2.39) | -0.7% |
| 12 | 75% | 6,570 | 440.27 | 433.09 | | 433.09 | (7.18) | -1.6% |
| 15 | 20% | 2,190 | 259.11 | 262.89 | | 262.89 | 3.78 | 1.5% |
| 15 | 30% | 3,285 | 311.30 | 312.69 | | 312.69 | 1.38 | 0.4% |
| 15 | 40% | 4,380 | 363.50 | 362.48 | | 362.48 | (1.01) | -0.3% |
| 15 | 50% | 5,475 | 415.69 | 412.28 | | 412.28 | (3.41) | -0.8% |
| 15 | 75% | 8,213 | 546.19 | 536.80 | | 536.80 | (9.39) | -1.7% |

ECT-1R Winter Average Energy On-Peak: 32%
Unbundled Transmission Charge: $/kWh

Supporting Schedules: N/A

Recap Schedules: N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| | Load | Monthly | under | | | under | | |
| kW | Factor | kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 3 | 20% | 438 | 82.28 | 85.19 | | 85.19 | 2.90 | 3.5% |
| 3 | 30% | 657 | 94.98 | 97.50 | | 97.50 | 2.52 | 2.6% |
| 3 | 40% | 876 | 107.68 | 109.81 | | 109.81 | 2.13 | 2.0% |
| 3 | 50% | 1,095 | 120.37 | 122.11 | | 122.11 | 1.74 | 1.4% |
| 3 | 75% | 1,643 | 152.14 | 152.91 | | 152.91 | 0.77 | 0.5% |
| 5 | 20% | 730 | 126.02 | 129.75 | | 129.75 | 3.73 | 3.0% |
| 5 | 30% | 1,095 | 147.18 | 150.26 | | 150.26 | 3.08 | 2.1% |
| 5 | 40% | 1,460 | 168.34 | 170.78 | | 170.78 | 2.44 | 1.4% |
| 5 | 50% | 1,825 | 189.50 | 191.29 | | 191.29 | 1.79 | 0.9% |
| 5 | 75% | 2,738 | 242.43 | 242.61 | | 242.61 | 0.18 | 0.1% |
| 8 | 20% | 1,168 | 191.62 | 196.59 | | 196.59 | 4.96 | 2.6% |
| 8 | 30% | 1,752 | 225.48 | 229.41 | | 229.41 | 3.93 | 1.7% |
| 8 | 40% | 2,336 | 259.34 | 262.23 | | 262.23 | 2.90 | 1.1% |
| 8 | 50% | 2,920 | 293.19 | 295.06 | | 295.06 | 1.87 | 0.6% |
| 8 | 75% | 4,380 | 377.83 | 377.12 | | 377.12 | (0.72) | -0.2% |
| 10 | 20% | 1,460 | 235.36 | 241.15 | | 241.15 | 5.79 | 2.5% |
| 10 | 30% | 2,190 | 277.68 | 282.18 | | 282.18 | 4.50 | 1.6% |
| 10 | 40% | 2,920 | 320.00 | 323.21 | | 323.21 | 3.21 | 1.0% |
| 10 | 50% | 3,650 | 362.32 | 364.24 | | 364.24 | 1.92 | 0.5% |
| 10 | 75% | 5,475 | 468.12 | 466.81 | | 466.81 | (1.31) | -0.3% |
| 12 | 20% | 1,752 | 279.10 | 285.71 | | 285.71 | 6.61 | 2.4% |
| 12 | 30% | 2,628 | 329.88 | 334.94 | | 334.94 | 5.06 | 1.5% |
| 12 | 40% | 3,504 | 380.66 | 384.18 | | 384.18 | 3.51 | 0.9% |
| 12 | 50% | 4,380 | 431.45 | 433.41 | | 433.41 | 1.97 | 0.5% |
| 12 | 75% | 6,570 | 558.41 | 556.50 | | 556.50 | (1.91) | -0.3% |
| 15 | 20% | 2,190 | 344.70 | 352.55 | | 352.55 | 7.85 | 2.3% |
| 15 | 30% | 3,285 | 408.18 | 414.09 | | 414.09 | 5.91 | 1.4% |
| 15 | 40% | 4,380 | 471.66 | 475.64 | | 475.64 | 3.98 | 0.8% |
| 15 | 50% | 5,475 | 535.14 | 537.18 | | 537.18 | 2.04 | 0.4% |
| 15 | 75% | 8,213 | 693.87 | 691.07 | | 691.07 | (2.80) | -0.4% |

ECT-1R Summer Average Energy On-Peak: 40%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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 | 64.15 | 65.75 | | 65.75 | 1.60 | 2.5% |
| 3 | 30% | 657 | 74.08 | 74.96 | | 74.96 | 0.87 | 1.2% |
| 3 | 40% | 876 | 84.02 | 84.16 | | 84.16 | 0.15 | 0.2% |
| 3 | 50% | 1,095 | 93.95 | 93.37 | | 93.37 | (0.58) | -0.6% |
| 3 | 75% | 1,643 | 118.80 | 116.41 | | 116.41 | (2.39) | -2.0% |
| 5 | 20% | 730 | 95.80 | 97.35 | | 97.35 | 1.55 | 1.6% |
| 5 | 30% | 1,095 | 112.35 | 112.70 | | 112.70 | 0.34 | 0.3% |
| 5 | 40% | 1,460 | 128.91 | 128.04 | | 128.04 | (0.87) | -0.7% |
| 5 | 50% | 1,825 | 145.46 | 143.39 | | 143.39 | (2.07) | -1.4% |
| 5 | 75% | 2,738 | 186.87 | 181.77 | | 181.77 | (5.10) | -2.7% |
| 8 | 20% | 1,168 | 143.27 | 144.76 | | 144.76 | 1.48 | 1.0% |
| 8 | 30% | 1,752 | 169.76 | 169.31 | | 169.31 | (0.45) | -0.3% |
| 8 | 40% | 2,336 | 196.24 | 193.86 | | 193.86 | (2.39) | -1.2% |
| 8 | 50% | 2,920 | 222.73 | 218.41 | | 218.41 | (4.32) | -1.9% |
| 8 | 75% | 4,380 | 288.94 | 279.79 | | 279.79 | (9.15) | -3.2% |
| 10 | 20% | 1,460 | 174.92 | 176.36 | | 176.36 | 1.44 | 0.8% |
| 10 | 30% | 2,190 | 208.03 | 207.05 | | 207.05 | (0.98) | -0.5% |
| 10 | 40% | 2,920 | 241.14 | 237.74 | | 237.74 | (3.40) | -1.4% |
| 10 | 50% | 3,650 | 274.24 | 268.43 | | 268.43 | (5.82) | -2.1% |
| 10 | 75% | 5,475 | 357.01 | 345.15 | | 345.15 | (11.86) | -3.3% |
| 12 | 20% | 1,752 | 206.57 | 207.96 | | 207.96 | 1.39 | 0.7% |
| 12 | 30% | 2,628 | 246.30 | 244.79 | | 244.79 | (1.51) | -0.6% |
| 12 | 40% | 3,504 | 286.03 | 281.61 | | 281.61 | (4.41) | -1.5% |
| 12 | 50% | 4,380 | 325.76 | 318.44 | | 318.44 | (7.31) | -2.2% |
| 12 | 75% | 6,570 | 425.07 | 410.51 | | 410.51 | (14.56) | -3.4% |
| 15 | 20% | 2,190 | 254.04 | 255.36 | | 255.36 | 1.32 | 0.5% |
| 15 | 30% | 3,285 | 303.70 | 301.40 | | 301.40 | (2.31) | -0.8% |
| 15 | 40% | 4,380 | 353.36 | 347.43 | | 347.43 | (5.93) | -1.7% |
| 15 | 50% | 5,475 | 403.02 | 393.47 | | 393.47 | (9.56) | -2.4% |
| 15 | 75% | 8,213 | 527.20 | 508.57 | | 508.57 | (18.62) | -3.5% |

ECT-2 Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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 | 82.28 | 85.19 | | 85.19 | 2.90 | 3.5% |
| 3 | 30% | 657 | 94.98 | 97.50 | | 97.50 | 2.52 | 2.6% |
| 3 | 40% | 876 | 107.68 | 109.81 | | 109.81 | 2.13 | 2.0% |
| 3 | 50% | 1,095 | 120.37 | 122.11 | | 122.11 | 1.74 | 1.4% |
| 3 | 75% | 1,643 | 152.14 | 152.91 | | 152.91 | 0.77 | 0.5% |
| 5 | 20% | 730 | 126.02 | 129.75 | | 129.75 | 3.73 | 3.0% |
| 5 | 30% | 1,095 | 147.18 | 150.26 | | 150.26 | 3.08 | 2.1% |
| 5 | 40% | 1,460 | 168.34 | 170.78 | | 170.78 | 2.44 | 1.4% |
| 5 | 50% | 1,825 | 189.50 | 191.29 | | 191.29 | 1.79 | 0.9% |
| 5 | 75% | 2,738 | 242.43 | 242.61 | | 242.61 | 0.18 | 0.1% |
| 8 | 20% | 1,168 | 191.62 | 196.59 | | 196.59 | 4.96 | 2.6% |
| 8 | 30% | 1,752 | 225.48 | 229.41 | | 229.41 | 3.93 | 1.7% |
| 8 | 40% | 2,336 | 259.34 | 262.23 | | 262.23 | 2.90 | 1.1% |
| 8 | 50% | 2,920 | 293.19 | 295.06 | | 295.06 | 1.87 | 0.6% |
| 8 | 75% | 4,380 | 377.83 | 377.12 | | 377.12 | (0.72) | -0.2% |
| 10 | 20% | 1,460 | 235.36 | 241.15 | | 241.15 | 5.79 | 2.5% |
| 10 | 30% | 2,190 | 277.68 | 282.18 | | 282.18 | 4.50 | 1.6% |
| 10 | 40% | 2,920 | 320.00 | 323.21 | | 323.21 | 3.21 | 1.0% |
| 10 | 50% | 3,650 | 362.32 | 364.24 | | 364.24 | 1.92 | 0.5% |
| 10 | 75% | 5,475 | 468.12 | 466.81 | | 466.81 | (1.31) | -0.3% |
| 12 | 20% | 1,752 | 279.10 | 285.71 | | 285.71 | 6.61 | 2.4% |
| 12 | 30% | 2,628 | 329.88 | 334.94 | | 334.94 | 5.06 | 1.5% |
| 12 | 40% | 3,504 | 380.66 | 384.18 | | 384.18 | 3.51 | 0.9% |
| 12 | 50% | 4,380 | 431.45 | 433.41 | | 433.41 | 1.97 | 0.5% |
| 12 | 75% | 6,570 | 558.41 | 556.50 | | 556.50 | (1.91) | -0.3% |
| 15 | 20% | 2,190 | 344.70 | 352.55 | | 352.55 | 7.85 | 2.3% |
| 15 | 30% | 3,285 | 408.18 | 414.09 | | 414.09 | 5.91 | 1.4% |
| 15 | 40% | 4,380 | 471.66 | 475.64 | | 475.64 | 3.98 | 0.8% |
| 15 | 50% | 5,475 | 535.14 | 537.18 | | 537.18 | 2.04 | 0.4% |
| 15 | 75% | 8,213 | 693.87 | 691.07 | | 691.07 | (2.80) | -0.4% |

ECT-2 Summer Average Energy On-Peak: 25%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Residential Bill Analysis**
**ET-SP Winter (November-April)**

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

| (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly | under | | | under | | |
| kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| 200 | 40.62 | 43.06 | | 43.06 | 2.44 | 6.0% |
| 250 | 46.61 | 49.24 | | 49.24 | 2.63 | 5.6% |
| 300 | 52.59 | 55.42 | | 55.42 | 2.82 | 5.4% |
| 350 | 58.58 | 61.59 | | 61.59 | 3.02 | 5.1% |
| 400 | 64.56 | 67.77 | | 67.77 | 3.21 | 5.0% |
| 450 | 70.55 | 73.95 | | 73.95 | 3.40 | 4.8% |
| 500 | 76.53 | 80.13 | | 80.13 | 3.59 | 4.7% |
| 550 | 82.52 | 86.31 | | 86.31 | 3.79 | 4.6% |
| 600 | 88.51 | 92.48 | | 92.48 | 3.98 | 4.5% |
| 650 | 94.49 | 98.66 | | 98.66 | 4.17 | 4.4% |
| 700 | 100.48 | 104.84 | | 104.84 | 4.36 | 4.3% |
| 750 | 106.46 | 111.02 | | 111.02 | 4.56 | 4.3% |
| 800 | 112.45 | 117.20 | | 117.20 | 4.75 | 4.2% |
| 850 | 118.43 | 123.37 | | 123.37 | 4.94 | 4.2% |
| 900 | 124.42 | 129.55 | | 129.55 | 5.13 | 4.1% |
| 950 | 130.40 | 135.73 | | 135.73 | 5.33 | 4.1% |
| 1,000 | 136.39 | 141.91 | | 141.91 | 5.52 | 4.0% |
| 1,100 | 148.36 | 154.26 | | 154.26 | 5.90 | 4.0% |
| 1,200 | 160.33 | 166.62 | | 166.62 | 6.29 | 3.9% |
| 1,300 | 172.30 | 178.98 | | 178.98 | 6.67 | 3.9% |
| 1,400 | 184.27 | 191.33 | | 191.33 | 7.06 | 3.8% |
| 1,500 | 196.24 | 203.69 | | 203.69 | 7.44 | 3.8% |
| 1,600 | 208.21 | 216.04 | | 216.04 | 7.83 | 3.8% |
| 1,700 | 220.18 | 228.40 | | 228.40 | 8.21 | 3.7% |
| 1,800 | 232.16 | 240.76 | | 240.76 | 8.60 | 3.7% |
| 1,900 | 244.13 | 253.11 | | 253.11 | 8.98 | 3.7% |
| 2,000 | 256.10 | 265.47 | | 265.47 | 9.37 | 3.7% |
| 2,200 | 280.04 | 290.18 | | 290.18 | 10.14 | 3.6% |
| 2,400 | 303.98 | 314.89 | | 314.89 | 10.91 | 3.6% |
| 2,600 | 327.92 | 339.60 | | 339.60 | 11.68 | 3.6% |
| 2,800 | 351.86 | 364.31 | | 364.31 | 12.45 | 3.5% |
| 3,000 | 375.81 | 389.03 | | 389.03 | 13.22 | 3.5% |

ET-SP Winter Average Energy On-Peak: 17%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Residential Bill Analysis**
**ET-SP Summer (May, September & October)**

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

| (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| 200 | 40.62 | 43.06 | | 43.06 | 2.44 | 6.0% |
| 250 | 46.61 | 49.24 | | 49.24 | 2.63 | 5.6% |
| 300 | 52.59 | 55.42 | | 55.42 | 2.82 | 5.4% |
| 350 | 58.58 | 61.59 | | 61.59 | 3.02 | 5.1% |
| 400 | 64.56 | 67.77 | | 67.77 | 3.21 | 5.0% |
| 450 | 70.55 | 73.95 | | 73.95 | 3.40 | 4.8% |
| 500 | 76.53 | 80.13 | | 80.13 | 3.59 | 4.7% |
| 550 | 82.52 | 86.31 | | 86.31 | 3.79 | 4.6% |
| 600 | 88.51 | 92.48 | | 92.48 | 3.98 | 4.5% |
| 650 | 94.49 | 98.66 | | 98.66 | 4.17 | 4.4% |
| 700 | 100.48 | 104.84 | | 104.84 | 4.36 | 4.3% |
| 750 | 106.46 | 111.02 | | 111.02 | 4.56 | 4.3% |
| 800 | 112.45 | 117.20 | | 117.20 | 4.75 | 4.2% |
| 850 | 118.43 | 123.37 | | 123.37 | 4.94 | 4.2% |
| 900 | 124.42 | 129.55 | | 129.55 | 5.13 | 4.1% |
| 950 | 130.40 | 135.73 | | 135.73 | 5.33 | 4.1% |
| 1,000 | 136.39 | 141.91 | | 141.91 | 5.52 | 4.0% |
| 1,100 | 148.36 | 154.26 | | 154.26 | 5.90 | 4.0% |
| 1,200 | 160.33 | 166.62 | | 166.62 | 6.29 | 3.9% |
| 1,300 | 172.30 | 178.98 | | 178.98 | 6.67 | 3.9% |
| 1,400 | 184.27 | 191.33 | | 191.33 | 7.06 | 3.8% |
| 1,500 | 196.24 | 203.69 | | 203.69 | 7.44 | 3.8% |
| 1,600 | 208.21 | 216.04 | | 216.04 | 7.83 | 3.8% |
| 1,700 | 220.18 | 228.40 | | 228.40 | 8.21 | 3.7% |
| 1,800 | 232.16 | 240.76 | | 240.76 | 8.60 | 3.7% |
| 1,900 | 244.13 | 253.11 | | 253.11 | 8.98 | 3.7% |
| 2,000 | 256.10 | 265.47 | | 265.47 | 9.37 | 3.7% |
| 2,200 | 280.04 | 290.18 | | 290.18 | 10.14 | 3.6% |
| 2,400 | 303.98 | 314.89 | | 314.89 | 10.91 | 3.6% |
| 2,600 | 327.92 | 339.60 | | 339.60 | 11.68 | 3.6% |
| 2,800 | 351.86 | 364.31 | | 364.31 | 12.45 | 3.5% |
| 3,000 | 375.81 | 389.03 | | 389.03 | 13.22 | 3.5% |

ET-SP Summer Average Energy On-Peak: 35%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Residential Bill Analysis**
**ET-SP Super Peak Summer (June-August)**

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

| (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| 200 | 48.12 | 49.24 | | 49.24 | 1.12 | 2.3% |
| 250 | 55.98 | 56.97 | | 56.97 | 0.99 | 1.8% |
| 300 | 63.84 | 64.69 | | 64.69 | 0.85 | 1.3% |
| 350 | 71.70 | 72.42 | | 72.42 | 0.71 | 1.0% |
| 400 | 79.56 | 80.14 | | 80.14 | 0.58 | 0.7% |
| 450 | 87.42 | 87.86 | | 87.86 | 0.44 | 0.5% |
| 500 | 95.28 | 95.59 | | 95.59 | 0.30 | 0.3% |
| 550 | 103.14 | 103.31 | | 103.31 | 0.17 | 0.2% |
| 600 | 111.01 | 111.04 | | 111.04 | 0.03 | 0.0% |
| 650 | 118.87 | 118.76 | | 118.76 | (0.10) | -0.1% |
| 700 | 126.73 | 126.49 | | 126.49 | (0.24) | -0.2% |
| 750 | 134.59 | 134.21 | | 134.21 | (0.38) | -0.3% |
| 800 | 142.45 | 141.93 | | 141.93 | (0.51) | -0.4% |
| 850 | 150.31 | 149.66 | | 149.66 | (0.65) | -0.4% |
| 900 | 158.17 | 157.38 | | 157.38 | (0.79) | -0.5% |
| 950 | 166.03 | 165.11 | | 165.11 | (0.92) | -0.6% |
| 1,000 | 173.89 | 172.83 | | 172.83 | (1.06) | -0.6% |
| 1,100 | 189.61 | 188.28 | | 188.28 | (1.33) | -0.7% |
| 1,200 | 205.33 | 203.73 | | 203.73 | (1.60) | -0.8% |
| 1,300 | 221.05 | 219.17 | | 219.17 | (1.88) | -0.8% |
| 1,400 | 236.77 | 234.62 | | 234.62 | (2.15) | -0.9% |
| 1,500 | 252.49 | 250.07 | | 250.07 | (2.42) | -1.0% |
| 1,600 | 268.21 | 265.52 | | 265.52 | (2.70) | -1.0% |
| 1,700 | 283.93 | 280.97 | | 280.97 | (2.97) | -1.0% |
| 1,800 | 299.66 | 296.41 | | 296.41 | (3.24) | -1.1% |
| 1,900 | 315.38 | 311.86 | | 311.86 | (3.51) | -1.1% |
| 2,000 | 331.10 | 327.31 | | 327.31 | (3.79) | -1.1% |
| 2,200 | 362.54 | 358.21 | | 358.21 | (4.33) | -1.2% |
| 2,400 | 393.98 | 389.10 | | 389.10 | (4.88) | -1.2% |
| 2,600 | 425.42 | 420.00 | | 420.00 | (5.42) | -1.3% |
| 2,800 | 456.86 | 450.90 | | 450.90 | (5.97) | -1.3% |
| 3,000 | 488.31 | 481.79 | | 481.79 | (6.51) | -1.3% |

ET-SP Summer Average Energy Super-Peak (Jun-Aug): 15%
ET-SP Summer Average Energy On-Peak (Jun-Aug): 20%
Unbundled Transmission Charge: $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 15 | 20% | 2,190 | 244.21 | 246.35 | | 246.35 | 2.14 | 0.9% |
| 15 | 30% | 3,285 | 334.17 | 334.98 | | 334.98 | 0.81 | 0.2% |
| 15 | 40% | 4,380 | 424.13 | 423.60 | | 423.60 | (0.53) | -0.1% |
| 15 | 50% | 5,475 | 514.09 | 512.23 | | 512.23 | (1.86) | -0.4% |
| 15 | 75% | 8,213 | 739.04 | 733.83 | | 733.83 | (5.21) | -0.7% |
| 30 | 20% | 4,380 | 456.47 | 457.56 | | 457.56 | 1.09 | 0.2% |
| 30 | 30% | 6,570 | 636.39 | 634.81 | | 634.81 | (1.58) | -0.2% |
| 30 | 40% | 8,760 | 816.31 | 812.06 | | 812.06 | (4.25) | -0.5% |
| 30 | 50% | 10,950 | 996.24 | 989.32 | | 989.32 | (6.92) | -0.7% |
| 30 | 75% | 16,425 | 1,446.04 | 1,432.44 | | 1,432.44 | (13.60) | -0.9% |
| 50 | 20% | 7,300 | 739.49 | 739.17 | | 739.17 | (0.32) | 0.0% |
| 50 | 30% | 10,950 | 1,039.36 | 1,034.59 | | 1,034.59 | (4.77) | -0.5% |
| 50 | 40% | 14,600 | 1,339.22 | 1,330.01 | | 1,330.01 | (9.21) | -0.7% |
| 50 | 50% | 18,250 | 1,639.09 | 1,625.43 | | 1,625.43 | (13.66) | -0.8% |
| 50 | 75% | 27,375 | 2,388.77 | 2,363.98 | | 2,363.98 | (24.79) | -1.0% |
| 100 | 20% | 14,600 | 1,447.02 | 1,443.20 | | 1,443.20 | (3.82) | -0.3% |
| 100 | 30% | 21,900 | 2,046.76 | 2,034.04 | | 2,034.04 | (12.72) | -0.6% |
| 100 | 40% | 29,200 | 2,646.50 | 2,624.87 | | 2,624.87 | (21.63) | -0.8% |
| 100 | 50% | 36,500 | 3,246.24 | 3,215.71 | | 3,215.71 | (30.53) | -0.9% |
| 100 | 75% | 54,750 | 4,745.58 | 4,692.81 | | 4,692.81 | (52.77) | -1.1% |
| 150 | 20% | 21,900 | 2,154.56 | 2,147.23 | | 2,147.23 | (7.33) | -0.3% |
| 150 | 30% | 32,850 | 3,054.17 | 3,033.48 | | 3,033.48 | (20.69) | -0.7% |
| 150 | 40% | 43,800 | 3,953.77 | 3,919.74 | | 3,919.74 | (34.03) | -0.9% |
| 150 | 50% | 54,750 | 4,853.38 | 4,806.00 | | 4,806.00 | (47.38) | -1.0% |
| 150 | 75% | 82,125 | 7,102.40 | 7,021.64 | | 7,021.64 | (80.76) | -1.1% |

| | | |
|---|---|---|
| General Service TOU Average Energy On-Peak: | 31% | |
| Unbundled Transmission Charge (<=20 kW): | | $/kWh |
| Unbundled Transmission Charge (>20 kW and <3,000): | | $/kW |

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| On-Peak kW | Load Factor | Monthly kWh | Monthly Bill under Present Rates | Components of Proposed Bill: Base | Transmission | Monthly Bill under Proposed Rates | Change: Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 15 | 20% | 2,190 | 270.39 | 272.49 | | 272.49 | 2.10 | 0.8% |
| 15 | 30% | 3,285 | 371.67 | 372.33 | | 372.33 | 0.66 | 0.2% |
| 15 | 40% | 4,380 | 472.96 | 472.18 | | 472.18 | (0.78) | -0.2% |
| 15 | 50% | 5,475 | 574.24 | 572.02 | | 572.02 | (2.22) | -0.4% |
| 15 | 75% | 8,213 | 827.51 | 821.68 | | 821.68 | (5.83) | -0.7% |
| 30 | 20% | 4,380 | 508.82 | 509.84 | | 509.84 | 1.02 | 0.2% |
| 30 | 30% | 6,570 | 711.40 | 709.52 | | 709.52 | (1.88) | -0.3% |
| 30 | 40% | 8,760 | 913.97 | 892.05 | | 892.05 | (21.92) | -2.4% |
| 30 | 50% | 10,950 | 1,116.54 | 1,108.90 | | 1,108.90 | (7.64) | -0.7% |
| 30 | 75% | 16,425 | 1,622.97 | 1,608.11 | | 1,608.11 | (14.86) | -0.9% |
| 50 | 20% | 7,300 | 826.74 | 826.30 | | 826.30 | (0.44) | -0.1% |
| 50 | 30% | 10,950 | 1,164.36 | 1,159.11 | | 1,159.11 | (5.25) | -0.5% |
| 50 | 40% | 14,600 | 1,501.98 | 1,491.92 | | 1,491.92 | (10.06) | -0.7% |
| 50 | 50% | 18,250 | 1,839.60 | 1,824.73 | | 1,824.73 | (14.87) | -0.8% |
| 50 | 75% | 27,375 | 2,683.65 | 2,656.76 | | 2,656.76 | (26.89) | -1.0% |
| 100 | 20% | 14,600 | 1,621.53 | 1,617.45 | | 1,617.45 | (4.08) | -0.3% |
| 100 | 30% | 21,900 | 2,296.77 | 2,283.07 | | 2,283.07 | (13.70) | -0.6% |
| 100 | 40% | 29,200 | 2,972.01 | 2,948.69 | | 2,948.69 | (23.32) | -0.8% |
| 100 | 50% | 36,500 | 3,647.25 | 3,614.32 | | 3,614.32 | (32.93) | -0.9% |
| 100 | 75% | 54,750 | 5,335.34 | 5,278.38 | | 5,278.38 | (56.96) | -1.1% |
| 150 | 20% | 21,900 | 2,416.32 | 2,408.60 | | 2,408.60 | (7.72) | -0.3% |
| 150 | 30% | 32,850 | 3,429.18 | 3,407.03 | | 3,407.03 | (22.15) | -0.6% |
| 150 | 40% | 43,800 | 4,442.03 | 4,405.47 | | 4,405.47 | (36.56) | -0.8% |
| 150 | 50% | 54,750 | 5,454.89 | 5,403.90 | | 5,403.90 | (50.99) | -0.9% |
| 150 | 75% | 82,125 | 7,987.04 | 7,899.99 | | 7,899.99 | (87.05) | -1.1% |

General Service TOU Average Energy On-Peak: 31%
Unbundled Transmission Charge (<=20 kW): $/kWh
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| - | 9.33 | 10.26 | | 10.26 | 0.93 | 10.0% |
| 20 | 11.92 | 12.35 | | 12.35 | 0.43 | 3.6% |
| 40 | 14.52 | 14.44 | | 14.44 | (0.08) | -0.5% |
| 60 | 17.11 | 16.53 | | 16.53 | (0.58) | -3.4% |
| 70 | 18.41 | 17.57 | | 17.57 | (0.84) | -4.6% |
| 80 | 19.70 | 18.61 | | 18.61 | (1.09) | -5.5% |
| 90 | 21.00 | 19.66 | | 19.66 | (1.34) | -6.4% |
| 100 | 22.30 | 20.70 | | 20.70 | (1.60) | -7.2% |
| 125 | 25.54 | 23.31 | | 23.31 | (2.23) | -8.7% |
| 150 | 28.78 | 25.92 | | 25.92 | (2.86) | -9.9% |
| 175 | 32.02 | 28.53 | | 28.53 | (3.49) | -10.9% |
| 200 | 35.26 | 31.14 | | 31.14 | (4.12) | -11.7% |
| 225 | 38.51 | 33.75 | | 33.75 | (4.76) | -12.4% |
| 250 | 41.75 | 36.36 | | 36.36 | (5.39) | -12.9% |
| 275 | 44.99 | 38.97 | | 38.97 | (6.02) | -13.4% |
| 300 | 48.23 | 41.58 | | 41.58 | (6.65) | -13.8% |
| 325 | 51.47 | 44.19 | | 44.19 | (7.28) | -14.1% |
| 350 | 54.71 | 46.80 | | 46.80 | (7.91) | -14.5% |
| 375 | 57.96 | 49.41 | | 49.41 | (8.55) | -14.8% |
| 400 | 61.20 | 52.02 | | 52.02 | (9.18) | -15.0% |
| 425 | 64.44 | 54.63 | | 54.63 | (9.81) | -15.2% |
| 450 | 67.68 | 57.24 | | 57.24 | (10.44) | -15.4% |
| 475 | 70.92 | 59.85 | | 59.85 | (11.07) | -15.6% |
| 500 | 74.17 | 62.46 | | 62.46 | (11.71) | -15.8% |
| 600 | 87.13 | 72.89 | | 72.89 | (14.24) | -16.3% |
| 700 | 100.10 | 83.33 | | 83.33 | (16.77) | -16.8% |
| 800 | 113.07 | 93.77 | | 93.77 | (19.30) | -17.1% |
| 900 | 126.03 | 104.21 | | 104.21 | (21.82) | -17.3% |
| 1,000 | 139.00 | 114.65 | | 114.65 | (24.35) | -17.5% |
| 1,500 | 203.84 | 166.84 | | 166.84 | (37.00) | -18.2% |
| 2,000 | 268.67 | 219.03 | | 219.03 | (49.64) | -18.5% |
| 2,500 | 333.51 | 271.22 | | 271.22 | (62.29) | -18.7% |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| - | 9.33 | 10.26 | | 10.26 | 0.93 | 10.0% |
| 20 | 12.22 | 13.30 | | 13.30 | 1.08 | 8.8% |
| 40 | 15.11 | 16.33 | | 16.33 | 1.22 | 8.1% |
| 60 | 18.00 | 19.36 | | 19.36 | 1.36 | 7.6% |
| 70 | 19.44 | 20.88 | | 20.88 | 1.44 | 7.4% |
| 80 | 20.89 | 22.40 | | 22.40 | 1.51 | 7.2% |
| 90 | 22.33 | 23.92 | | 23.92 | 1.59 | 7.1% |
| 100 | 23.78 | 25.43 | | 25.43 | 1.65 | 6.9% |
| 125 | 27.39 | 29.22 | | 29.22 | 1.83 | 6.7% |
| 150 | 31.00 | 33.02 | | 33.02 | 2.02 | 6.5% |
| 175 | 34.61 | 36.81 | | 36.81 | 2.20 | 6.4% |
| 200 | 38.22 | 40.60 | | 40.60 | 2.38 | 6.2% |
| 225 | 41.84 | 44.39 | | 44.39 | 2.55 | 6.1% |
| 250 | 45.45 | 48.19 | | 48.19 | 2.74 | 6.0% |
| 275 | 49.06 | 51.98 | | 51.98 | 2.92 | 5.9% |
| 300 | 52.67 | 55.77 | | 55.77 | 3.10 | 5.9% |
| 325 | 56.28 | 59.56 | | 59.56 | 3.28 | 5.8% |
| 350 | 59.89 | 63.36 | | 63.36 | 3.47 | 5.8% |
| 375 | 63.51 | 67.15 | | 67.15 | 3.64 | 5.7% |
| 400 | 67.12 | 70.94 | | 70.94 | 3.82 | 5.7% |
| 425 | 70.73 | 74.73 | | 74.73 | 4.00 | 5.7% |
| 450 | 74.34 | 78.53 | | 78.53 | 4.19 | 5.6% |
| 475 | 77.95 | 82.32 | | 82.32 | 4.37 | 5.6% |
| 500 | 81.57 | 86.11 | | 86.11 | 4.54 | 5.6% |
| 600 | 96.01 | 101.28 | | 101.28 | 5.27 | 5.5% |
| 700 | 110.46 | 116.45 | | 116.45 | 5.99 | 5.4% |
| 800 | 124.91 | 131.62 | | 131.62 | 6.71 | 5.4% |
| 900 | 139.35 | 146.79 | | 146.79 | 7.44 | 5.3% |
| 1,000 | 153.80 | 161.96 | | 161.96 | 8.16 | 5.3% |
| 1,500 | 226.04 | 237.80 | | 237.80 | 11.76 | 5.2% |
| 2,000 | 298.27 | 313.65 | | 313.65 | 15.38 | 5.2% |
| 2,500 | 370.51 | 389.50 | | 389.50 | 18.99 | 5.1% |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 5 | 15% | 548 | 83.25 | 83.25 | | 83.25 | - | 0.0% |
| 5 | 30% | 1,095 | 146.22 | 146.22 | | 146.22 | - | 0.0% |
| 5 | 45% | 1,643 | 209.30 | 209.30 | | 209.30 | - | 0.0% |
| 5 | 60% | 2,190 | 272.27 | 272.27 | | 272.27 | - | 0.0% |
| 5 | 75% | 2,738 | 335.36 | 335.36 | | 335.36 | - | 0.0% |
| | | | | - | | | | |
| 10 | 15% | 1,095 | 146.22 | 146.22 | | 146.22 | - | 0.0% |
| 10 | 30% | 2,190 | 272.27 | 272.27 | | 272.27 | - | 0.0% |
| 10 | 45% | 3,285 | 398.33 | 398.33 | | 398.33 | - | 0.0% |
| 10 | 60% | 4,380 | 524.39 | 524.39 | | 524.39 | - | 0.0% |
| 10 | 75% | 5,475 | 621.89 | 621.89 | | 621.89 | - | 0.0% |
| | | | | - | | | | |
| 15 | 15% | 1,643 | 209.30 | 209.30 | | 209.30 | - | 0.0% |
| 15 | 30% | 3,285 | 398.33 | 398.33 | | 398.33 | - | 0.0% |
| 15 | 45% | 4,928 | 587.47 | 587.47 | | 587.47 | - | 0.0% |
| 15 | 60% | 6,570 | 682.13 | 682.13 | | 682.13 | - | 0.0% |
| 15 | 75% | 8,213 | 772.51 | 772.51 | | 772.51 | - | 0.0% |
| | | | | - | | | | |
| 20 | 15% | 2,190 | 272.27 | 272.27 | | 272.27 | - | 0.0% |
| 20 | 30% | 4,380 | 524.39 | 524.39 | | 524.39 | - | 0.0% |
| 20 | 45% | 6,570 | 682.13 | 682.13 | | 682.13 | - | 0.0% |
| 20 | 60% | 8,760 | 802.60 | 802.60 | | 802.60 | - | 0.0% |
| 20 | 75% | 10,950 | 923.07 | 923.07 | | 923.07 | - | 0.0% |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| | Load | Monthly | under | | | under | | |
| kW | Factor | kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 5 | 15% | 548 | 92.83 | 92.83 | | 92.83 | - | 0.0% |
| 5 | 30% | 1,095 | 165.37 | 165.37 | | 165.37 | - | 0.0% |
| 5 | 45% | 1,643 | 238.04 | 238.04 | | 238.04 | - | 0.0% |
| 5 | 60% | 2,190 | 310.58 | 310.58 | | 310.58 | - | 0.0% |
| 5 | 75% | 2,738 | 383.25 | 383.25 | | 383.25 | - | 0.0% |
| | | | | - | | | | |
| 10 | 15% | 1,095 | 165.37 | 165.37 | | 165.37 | - | 0.0% |
| 10 | 30% | 2,190 | 310.58 | 310.58 | | 310.58 | - | 0.0% |
| 10 | 45% | 3,285 | 455.78 | 455.78 | | 455.78 | - | 0.0% |
| 10 | 60% | 4,380 | 600.99 | 600.99 | | 600.99 | - | 0.0% |
| 10 | 75% | 5,475 | 717.65 | 717.65 | | 717.65 | - | 0.0% |
| | | | | - | | | | |
| 15 | 15% | 1,643 | 238.04 | 238.04 | | 238.04 | - | 0.0% |
| 15 | 30% | 3,285 | 455.78 | 455.78 | | 455.78 | - | 0.0% |
| 15 | 45% | 4,928 | 673.66 | 673.66 | | 673.66 | - | 0.0% |
| 15 | 60% | 6,570 | 797.05 | 797.05 | | 797.05 | - | 0.0% |
| 15 | 75% | 8,213 | 916.18 | 916.18 | | 916.18 | - | 0.0% |
| | | | | - | | | | |
| 20 | 15% | 2,190 | 310.58 | 310.58 | | 310.58 | - | 0.0% |
| 20 | 30% | 4,380 | 600.99 | 600.99 | | 600.99 | - | 0.0% |
| 20 | 45% | 6,570 | 797.05 | 797.05 | | 797.05 | - | 0.0% |
| 20 | 60% | 8,760 | 955.85 | 955.85 | | 955.85 | - | 0.0% |
| 20 | 75% | 10,950 | 1,114.64 | 1,114.64 | | 1,114.64 | - | 0.0% |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 21 | 15% | 2,300 | 423.18 | 423.18 | | 423.18 | - | 0.0% |
| 21 | 30% | 4,599 | 605.71 | 605.71 | | 605.71 | - | 0.0% |
| 21 | 45% | 6,899 | 706.19 | 706.19 | | 706.19 | - | 0.0% |
| 21 | 60% | 9,198 | 806.64 | 806.64 | | 806.64 | - | 0.0% |
| 21 | 75% | 11,498 | 907.12 | 907.12 | | 907.12 | - | 0.0% |
| | | | | - | | | | |
| 40 | 15% | 4,380 | 787.74 | 787.74 | | 787.74 | - | 0.0% |
| 40 | 30% | 8,760 | 1,135.48 | 1,135.48 | | 1,135.48 | - | 0.0% |
| 40 | 45% | 13,140 | 1,326.85 | 1,326.85 | | 1,326.85 | - | 0.0% |
| 40 | 60% | 17,520 | 1,518.21 | 1,518.21 | | 1,518.21 | - | 0.0% |
| 40 | 75% | 21,900 | 1,709.57 | 1,709.57 | | 1,709.57 | - | 0.0% |
| | | | | - | | | | |
| 60 | 15% | 6,570 | 1,171.53 | 1,171.53 | | 1,171.53 | - | 0.0% |
| 60 | 30% | 13,140 | 1,693.15 | 1,693.15 | | 1,693.15 | - | 0.0% |
| 60 | 45% | 19,710 | 1,980.19 | 1,980.19 | | 1,980.19 | - | 0.0% |
| 60 | 60% | 26,280 | 2,267.23 | 2,267.23 | | 2,267.23 | - | 0.0% |
| 60 | 75% | 32,850 | 2,554.28 | 2,554.28 | | 2,554.28 | - | 0.0% |
| | | | | - | | | | |
| 80 | 15% | 8,760 | 1,555.32 | 1,555.32 | | 1,555.32 | - | 0.0% |
| 80 | 30% | 17,520 | 2,250.81 | 2,250.81 | | 2,250.81 | - | 0.0% |
| 80 | 45% | 26,280 | 2,633.53 | 2,633.53 | | 2,633.53 | - | 0.0% |
| 80 | 60% | 35,040 | 3,016.26 | 3,016.26 | | 3,016.26 | - | 0.0% |
| 80 | 75% | 43,800 | 3,398.98 | 3,398.98 | | 3,398.98 | - | 0.0% |
| | | | | - | | | | |
| 90 | 15% | 9,855 | 1,747.21 | 1,747.21 | | 1,747.21 | - | 0.0% |
| 90 | 30% | 19,710 | 2,529.64 | 2,529.64 | | 2,529.64 | - | 0.0% |
| 90 | 45% | 29,565 | 2,960.20 | 2,960.20 | | 2,960.20 | - | 0.0% |
| 90 | 60% | 39,420 | 3,390.77 | 3,390.77 | | 3,390.77 | - | 0.0% |
| 90 | 75% | 49,275 | 3,821.33 | 3,821.33 | | 3,821.33 | - | 0.0% |
| | | | | - | | | | |
| 100 | 15% | 10,950 | 1,939.11 | 1,939.11 | | 1,939.11 | - | 0.0% |
| 100 | 30% | 21,900 | 2,808.47 | 2,808.47 | | 2,808.47 | - | 0.0% |
| 100 | 45% | 32,850 | 3,286.88 | 3,286.88 | | 3,286.88 | - | 0.0% |
| 100 | 60% | 43,800 | 3,765.28 | 3,765.28 | | 3,765.28 | - | 0.0% |
| 100 | 75% | 54,750 | 4,243.69 | 4,243.69 | | 4,243.69 | - | 0.0% |

Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 21 | 15% | 2,300 | 462.60 | 462.60 | | 462.60 | - | 0.0% |
| 21 | 30% | 4,599 | 684.53 | 684.53 | | 684.53 | - | 0.0% |
| 21 | 45% | 6,899 | 824.44 | 824.44 | | 824.44 | - | 0.0% |
| 21 | 60% | 9,198 | 964.29 | 964.29 | | 964.29 | - | 0.0% |
| 21 | 75% | 11,498 | 1,104.20 | 1,104.20 | | 1,104.20 | - | 0.0% |
| | | | | - | | | | |
| 40 | 15% | 4,380 | 862.81 | 862.81 | | 862.81 | - | 0.0% |
| 40 | 30% | 8,760 | 1,285.63 | 1,285.63 | | 1,285.63 | - | 0.0% |
| 40 | 45% | 13,140 | 1,552.07 | 1,552.07 | | 1,552.07 | - | 0.0% |
| 40 | 60% | 17,520 | 1,818.50 | 1,818.50 | | 1,818.50 | - | 0.0% |
| 40 | 75% | 21,900 | 2,084.94 | 2,084.94 | | 2,084.94 | - | 0.0% |
| | | | | - | | | | |
| 60 | 15% | 6,570 | 1,284.14 | 1,284.14 | | 1,284.14 | - | 0.0% |
| 60 | 30% | 13,140 | 1,918.37 | 1,918.37 | | 1,918.37 | - | 0.0% |
| 60 | 45% | 19,710 | 2,318.02 | 2,318.02 | | 2,318.02 | - | 0.0% |
| 60 | 60% | 26,280 | 2,717.67 | 2,717.67 | | 2,717.67 | - | 0.0% |
| 60 | 75% | 32,850 | 3,117.33 | 3,117.33 | | 3,117.33 | - | 0.0% |
| | | | | - | | | | |
| 80 | 15% | 8,760 | 1,705.46 | 1,705.46 | | 1,705.46 | - | 0.0% |
| 80 | 30% | 17,520 | 2,551.10 | 2,551.10 | | 2,551.10 | - | 0.0% |
| 80 | 45% | 26,280 | 3,083.97 | 3,083.97 | | 3,083.97 | - | 0.0% |
| 80 | 60% | 35,040 | 3,616.84 | 3,616.84 | | 3,616.84 | - | 0.0% |
| 80 | 75% | 43,800 | 4,149.71 | 4,149.71 | | 4,149.71 | - | 0.0% |
| | | | | - | | | | |
| 90 | 15% | 9,855 | 1,916.13 | 1,916.13 | | 1,916.13 | - | 0.0% |
| 90 | 30% | 19,710 | 2,867.47 | 2,867.47 | | 2,867.47 | - | 0.0% |
| 90 | 45% | 29,565 | 3,466.95 | 3,466.95 | | 3,466.95 | - | 0.0% |
| 90 | 60% | 39,420 | 4,066.43 | 4,066.43 | | 4,066.43 | - | 0.0% |
| 90 | 75% | 49,275 | 4,665.91 | 4,665.91 | | 4,665.91 | - | 0.0% |
| | | | | - | | | | |
| 100 | 15% | 10,950 | 2,126.79 | 2,126.79 | | 2,126.79 | - | 0.0% |
| 100 | 30% | 21,900 | 3,183.84 | 3,183.84 | | 3,183.84 | - | 0.0% |
| 100 | 45% | 32,850 | 3,849.93 | 3,849.93 | | 3,849.93 | - | 0.0% |
| 100 | 60% | 43,800 | 4,516.01 | 4,516.01 | | 4,516.01 | - | 0.0% |
| 100 | 75% | 54,750 | 5,182.10 | 5,182.10 | | 5,182.10 | - | 0.0% |

Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

## Arizona Public Service Company
## Test Year Ending December 2010
## 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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 101 | 15% | 11,060 | 1,957.79 | 1,957.79 | | 1,957.79 | - | 0.0% |
| 101 | 30% | 22,119 | 2,828.73 | 2,828.73 | | 2,828.73 | - | 0.0% |
| 101 | 45% | 33,179 | 3,308.07 | 3,308.07 | | 3,308.07 | - | 0.0% |
| 101 | 60% | 44,238 | 3,787.37 | 3,787.37 | | 3,787.37 | - | 0.0% |
| 101 | 75% | 55,298 | 4,266.71 | 4,266.71 | | 4,266.71 | - | 0.0% |
| | | | | - | | | | |
| 150 | 15% | 16,425 | 2,670.34 | 2,670.34 | | 2,670.34 | - | 0.0% |
| 150 | 30% | 32,850 | 3,963.89 | 3,963.89 | | 3,963.89 | - | 0.0% |
| 150 | 45% | 49,275 | 4,675.75 | 4,675.75 | | 4,675.75 | - | 0.0% |
| 150 | 60% | 65,700 | 5,387.61 | 5,387.61 | | 5,387.61 | - | 0.0% |
| 150 | 75% | 82,125 | 6,099.47 | 6,099.47 | | 6,099.47 | - | 0.0% |
| | | | | - | | | | |
| 200 | 15% | 21,900 | 3,397.48 | 3,397.48 | | 3,397.48 | - | 0.0% |
| 200 | 30% | 43,800 | 5,122.21 | 5,122.21 | | 5,122.21 | - | 0.0% |
| 200 | 45% | 65,700 | 6,071.36 | 6,071.36 | | 6,071.36 | - | 0.0% |
| 200 | 60% | 87,600 | 7,020.50 | 7,020.50 | | 7,020.50 | - | 0.0% |
| 200 | 75% | 109,500 | 7,969.65 | 7,969.65 | | 7,969.65 | - | 0.0% |
| | | | | - | | | | |
| 300 | 15% | 32,850 | 4,851.76 | 4,851.76 | | 4,851.76 | - | 0.0% |
| 300 | 30% | 65,700 | 7,438.86 | 7,438.86 | | 7,438.86 | - | 0.0% |
| 300 | 45% | 98,550 | 8,862.58 | 8,862.58 | | 8,862.58 | - | 0.0% |
| 300 | 60% | 131,400 | 10,286.30 | 10,286.30 | | 10,286.30 | - | 0.0% |
| 300 | 75% | 164,250 | 11,710.02 | 11,710.02 | | 11,710.02 | - | 0.0% |
| | | | | - | | | | |
| 350 | 15% | 38,325 | 5,578.90 | 5,578.90 | | 5,578.90 | - | 0.0% |
| 350 | 30% | 76,650 | 8,597.18 | 8,597.18 | | 8,597.18 | - | 0.0% |
| 350 | 45% | 114,975 | 10,258.19 | 10,258.19 | | 10,258.19 | - | 0.0% |
| 350 | 60% | 153,300 | 11,919.19 | 11,919.19 | | 11,919.19 | - | 0.0% |
| 350 | 75% | 191,625 | 13,580.20 | 13,580.20 | | 13,580.20 | - | 0.0% |
| | | | | - | | | | |
| 400 | 15% | 43,800 | 6,306.04 | 6,306.04 | | 6,306.04 | - | 0.0% |
| 400 | 30% | 87,600 | 9,755.50 | 9,755.50 | | 9,755.50 | - | 0.0% |
| 400 | 45% | 131,400 | 11,653.80 | 11,653.80 | | 11,653.80 | - | 0.0% |
| 400 | 60% | 175,200 | 13,552.09 | 13,552.09 | | 13,552.09 | - | 0.0% |
| 400 | 75% | 219,000 | 15,450.38 | 15,450.38 | | 15,450.38 | - | 0.0% |

Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 101 | 15% | 11,060 | 2,145.92 | 2,145.92 | | 2,145.92 | - | 0.0% |
| 101 | 30% | 22,119 | 3,204.96 | 3,204.96 | | 3,204.96 | - | 0.0% |
| 101 | 45% | 33,179 | 3,872.32 | 3,872.32 | | 3,872.32 | - | 0.0% |
| 101 | 60% | 44,238 | 4,539.62 | 4,539.62 | | 4,539.62 | - | 0.0% |
| 101 | 75% | 55,298 | 5,206.98 | 5,206.98 | | 5,206.98 | - | 0.0% |
| | | | | - | | | | |
| 150 | 15% | 16,425 | 2,949.73 | 2,949.73 | | 2,949.73 | - | 0.0% |
| 150 | 30% | 32,850 | 4,522.64 | 4,522.64 | | 4,522.64 | - | 0.0% |
| 150 | 45% | 49,275 | 5,513.72 | 5,513.72 | | 5,513.72 | - | 0.0% |
| 150 | 60% | 65,700 | 6,504.81 | 6,504.81 | | 6,504.81 | - | 0.0% |
| 150 | 75% | 82,125 | 7,495.89 | 7,495.89 | | 7,495.89 | - | 0.0% |
| | | | | - | | | | |
| 200 | 15% | 21,900 | 3,770.00 | 3,770.00 | | 3,770.00 | - | 0.0% |
| 200 | 30% | 43,800 | 5,867.21 | 5,867.21 | | 5,867.21 | - | 0.0% |
| 200 | 45% | 65,700 | 7,188.66 | 7,188.66 | | 7,188.66 | - | 0.0% |
| 200 | 60% | 87,600 | 8,510.10 | 8,510.10 | | 8,510.10 | - | 0.0% |
| 200 | 75% | 109,500 | 9,831.55 | 9,831.55 | | 9,831.55 | - | 0.0% |
| | | | | - | | | | |
| 300 | 15% | 32,850 | 5,410.54 | 5,410.54 | | 5,410.54 | - | 0.0% |
| 300 | 30% | 65,700 | 8,556.36 | 8,556.36 | | 8,556.36 | - | 0.0% |
| 300 | 45% | 98,550 | 10,538.53 | 10,538.53 | | 10,538.53 | - | 0.0% |
| 300 | 60% | 131,400 | 12,520.70 | 12,520.70 | | 12,520.70 | - | 0.0% |
| 300 | 75% | 164,250 | 14,502.87 | 14,502.87 | | 14,502.87 | - | 0.0% |
| | | | | - | | | | |
| 350 | 15% | 38,325 | 6,230.81 | 6,230.81 | | 6,230.81 | - | 0.0% |
| 350 | 30% | 76,650 | 9,900.93 | 9,900.93 | | 9,900.93 | - | 0.0% |
| 350 | 45% | 114,975 | 12,213.46 | 12,213.46 | | 12,213.46 | - | 0.0% |
| 350 | 60% | 153,300 | 14,525.99 | 14,525.99 | | 14,525.99 | - | 0.0% |
| 350 | 75% | 191,625 | 16,838.52 | 16,838.52 | | 16,838.52 | - | 0.0% |
| | | | | - | | | | |
| 400 | 15% | 43,800 | 7,051.08 | 7,051.08 | | 7,051.08 | - | 0.0% |
| 400 | 30% | 87,600 | 11,245.50 | 11,245.50 | | 11,245.50 | - | 0.0% |
| 400 | 45% | 131,400 | 13,888.40 | 13,888.40 | | 13,888.40 | - | 0.0% |
| 400 | 60% | 175,200 | 16,531.29 | 16,531.29 | | 16,531.29 | - | 0.0% |
| 400 | 75% | 219,000 | 19,174.18 | 19,174.18 | | 19,174.18 | - | 0.0% |

Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 401 | 15% | 43,910 | 6,191.72 | 6,191.72 | | 6,191.72 | - | 0.0% |
| 401 | 30% | 87,819 | 9,573.93 | 9,573.93 | | 9,573.93 | - | 0.0% |
| 401 | 45% | 131,729 | 11,435.28 | 11,435.28 | | 11,435.28 | - | 0.0% |
| 401 | 60% | 175,638 | 13,296.58 | 13,296.58 | | 13,296.58 | - | 0.0% |
| 401 | 75% | 219,548 | 15,157.92 | 15,157.92 | | 15,157.92 | - | 0.0% |
| | | | | - | | | | |
| 600 | 15% | 65,700 | 9,022.22 | 9,022.22 | | 9,022.22 | - | 0.0% |
| 600 | 30% | 131,400 | 14,082.96 | 14,082.96 | | 14,082.96 | - | 0.0% |
| 600 | 45% | 197,100 | 16,867.98 | 16,867.98 | | 16,867.98 | - | 0.0% |
| 600 | 60% | 262,800 | 19,653.00 | 19,653.00 | | 19,653.00 | - | 0.0% |
| 600 | 75% | 328,500 | 22,438.03 | 22,438.03 | | 22,438.03 | - | 0.0% |
| | | | | - | | | | |
| 800 | 15% | 87,600 | 11,866.99 | 11,866.99 | | 11,866.99 | - | 0.0% |
| 800 | 30% | 175,200 | 18,614.64 | 18,614.64 | | 18,614.64 | - | 0.0% |
| 800 | 45% | 262,800 | 22,328.00 | 22,328.00 | | 22,328.00 | - | 0.0% |
| 800 | 60% | 350,400 | 26,041.37 | 26,041.37 | | 26,041.37 | - | 0.0% |
| 800 | 75% | 438,000 | 29,754.73 | 29,754.73 | | 29,754.73 | - | 0.0% |
| | | | | - | | | | |
| 1,000 | 15% | 109,500 | 14,711.76 | 14,711.76 | | 14,711.76 | - | 0.0% |
| 1,000 | 30% | 219,000 | 23,146.32 | 23,146.32 | | 23,146.32 | - | 0.0% |
| 1,000 | 45% | 328,500 | 27,788.03 | 27,788.03 | | 27,788.03 | - | 0.0% |
| 1,000 | 60% | 438,000 | 32,429.73 | 32,429.73 | | 32,429.73 | - | 0.0% |
| 1,000 | 75% | 547,500 | 37,071.44 | 37,071.44 | | 37,071.44 | - | 0.0% |
| | | | | - | | | | |
| 1,500 | 15% | 164,250 | 21,823.69 | 21,823.69 | | 21,823.69 | - | 0.0% |
| 1,500 | 30% | 328,500 | 34,475.53 | 34,475.53 | | 34,475.53 | - | 0.0% |
| 1,500 | 45% | 492,750 | 41,438.08 | 41,438.08 | | 41,438.08 | - | 0.0% |
| 1,500 | 60% | 657,000 | 48,400.64 | 48,400.64 | | 48,400.64 | - | 0.0% |
| 1,500 | 75% | 821,250 | 55,363.20 | 55,363.20 | | 55,363.20 | - | 0.0% |
| | | | | - | | | | |
| 3,000 | 15% | 328,500 | 43,159.46 | 43,159.46 | | 43,159.46 | - | 0.0% |
| 3,000 | 30% | 657,000 | 68,463.14 | 68,463.14 | | 68,463.14 | - | 0.0% |
| 3,000 | 45% | 985,500 | 82,388.26 | 82,388.26 | | 82,388.26 | - | 0.0% |
| 3,000 | 60% | 1,314,000 | 96,313.37 | 96,313.37 | | 96,313.37 | - | 0.0% |
| 3,000 | 75% | 1,642,500 | 110,238.49 | 110,238.49 | | 110,238.49 | - | 0.0% |

Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 401 | 15% | 43,910 | 6,921.94 | 6,921.94 | - | 6,921.94 | - | 0.0% |
| 401 | 30% | 87,819 | 11,034.36 | 11,034.36 | | 11,034.36 | - | 0.0% |
| 401 | 45% | 131,729 | 13,625.93 | 13,625.93 | | 13,625.93 | - | 0.0% |
| 401 | 60% | 175,638 | 16,217.44 | 16,217.44 | | 16,217.44 | - | 0.0% |
| 401 | 75% | 219,548 | 18,809.01 | 18,809.01 | | 18,809.01 | - | 0.0% |
| | | | | - | | | | |
| 600 | 15% | 65,700 | 10,114.81 | 10,114.81 | | 10,114.81 | - | 0.0% |
| 600 | 30% | 131,400 | 16,268.14 | 16,268.14 | | 16,268.14 | - | 0.0% |
| 600 | 45% | 197,100 | 20,145.75 | 20,145.75 | | 20,145.75 | - | 0.0% |
| 600 | 60% | 262,800 | 24,023.37 | 24,023.37 | | 24,023.37 | - | 0.0% |
| 600 | 75% | 328,500 | 27,900.98 | 27,900.98 | | 27,900.98 | - | 0.0% |
| | | | | - | | | | |
| 800 | 15% | 87,600 | 13,323.78 | 13,323.78 | | 13,323.78 | - | 0.0% |
| 800 | 30% | 175,200 | 21,528.21 | 21,528.21 | | 21,528.21 | - | 0.0% |
| 800 | 45% | 262,800 | 26,698.37 | 26,698.37 | | 26,698.37 | - | 0.0% |
| 800 | 60% | 350,400 | 31,868.52 | 31,868.52 | | 31,868.52 | - | 0.0% |
| 800 | 75% | 438,000 | 37,038.67 | 37,038.67 | | 37,038.67 | - | 0.0% |
| | | | | - | | | | |
| 1,000 | 15% | 109,500 | 16,532.75 | 16,532.75 | | 16,532.75 | - | 0.0% |
| 1,000 | 30% | 219,000 | 26,788.29 | 26,788.29 | | 26,788.29 | - | 0.0% |
| 1,000 | 45% | 328,500 | 33,250.98 | 33,250.98 | | 33,250.98 | - | 0.0% |
| 1,000 | 60% | 438,000 | 39,713.67 | 39,713.67 | | 39,713.67 | - | 0.0% |
| 1,000 | 75% | 547,500 | 46,176.36 | 46,176.36 | | 46,176.36 | - | 0.0% |
| | | | | - | | | | |
| 1,500 | 15% | 164,250 | 24,555.16 | 24,555.16 | | 24,555.16 | - | 0.0% |
| 1,500 | 30% | 328,500 | 39,938.48 | 39,938.48 | | 39,938.48 | - | 0.0% |
| 1,500 | 45% | 492,750 | 49,632.52 | 49,632.52 | | 49,632.52 | - | 0.0% |
| 1,500 | 60% | 657,000 | 59,326.55 | 59,326.55 | | 59,326.55 | - | 0.0% |
| 1,500 | 75% | 821,250 | 69,020.59 | 69,020.59 | | 69,020.59 | - | 0.0% |
| | | | | - | | | | |
| 3,000 | 15% | 328,500 | 48,622.42 | 48,622.42 | | 48,622.42 | - | 0.0% |
| 3,000 | 30% | 657,000 | 79,389.05 | 79,389.05 | | 79,389.05 | - | 0.0% |
| 3,000 | 45% | 985,500 | 98,777.12 | 98,777.12 | | 98,777.12 | - | 0.0% |
| 3,000 | 60% | 1,314,000 | 118,165.19 | 118,165.19 | | 118,165.19 | - | 0.0% |
| 3,000 | 75% | 1,642,500 | 137,553.26 | 137,553.26 | | 137,553.26 | - | 0.0% |

Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| On-Peak kW | Off-Peak kW | Load Factor | Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 5 | 7.5 | 15% | 821 | 120.22 | 120.22 | | 120.22 | - | 0.0% |
| 5 | 7.5 | 30% | 1,643 | 219.26 | 219.26 | | 219.26 | - | 0.0% |
| 5 | 7.5 | 45% | 2,464 | 318.18 | 318.18 | | 318.18 | - | 0.0% |
| 5 | 7.5 | 60% | 3,285 | 417.10 | 417.10 | | 417.10 | - | 0.0% |
| 5 | 7.5 | 75% | 4,106 | 516.02 | 516.02 | | 516.02 | - | 0.0% |
| | | | | | - | | | | |
| 10 | 12 | 15% | 1,314 | 179.62 | 179.62 | | 179.62 | - | 0.0% |
| 10 | 12 | 30% | 2,628 | 337.94 | 337.94 | | 337.94 | - | 0.0% |
| 10 | 12 | 45% | 3,942 | 496.26 | 496.26 | | 496.26 | - | 0.0% |
| 10 | 12 | 60% | 5,256 | 654.58 | 654.58 | | 654.58 | - | 0.0% |
| 10 | 12 | 75% | 6,570 | 812.90 | 812.90 | | 812.90 | - | 0.0% |
| | | | | | - | | | | |
| 15 | 20 | 15% | 2,190 | 285.17 | 285.17 | | 285.17 | - | 0.0% |
| 15 | 20 | 30% | 4,380 | 549.04 | 549.04 | | 549.04 | - | 0.0% |
| 15 | 20 | 45% | 6,570 | 812.90 | 812.90 | | 812.90 | - | 0.0% |
| 15 | 20 | 60% | 8,760 | 998.39 | 998.39 | | 998.39 | - | 0.0% |
| 15 | 20 | 75% | 10,950 | 1,148.85 | 1,148.85 | | 1,148.85 | - | 0.0% |
| | | | | | - | | | | |
| 20 | 25 | 15% | 2,738 | 351.20 | 351.20 | | 351.20 | - | 0.0% |
| 20 | 25 | 30% | 5,475 | 680.97 | 680.97 | | 680.97 | - | 0.0% |
| 20 | 25 | 45% | 8,213 | 960.81 | 960.81 | | 960.81 | - | 0.0% |
| 20 | 25 | 60% | 10,950 | 1,148.85 | 1,148.85 | | 1,148.85 | - | 0.0% |
| 20 | 25 | 75% | 13,688 | 1,336.96 | 1,336.96 | | 1,336.96 | - | 0.0% |

General Service TOU Average Energy On-Peak: 31%
Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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*

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 5 | 7.5 | 15% | 821 | 134.60 | 134.60 | | 134.60 | - | 0.0% |
| 5 | 7.5 | 30% | 1,643 | 248.03 | 248.03 | | 248.03 | - | 0.0% |
| 5 | 7.5 | 45% | 2,464 | 361.33 | 361.33 | | 361.33 | - | 0.0% |
| 5 | 7.5 | 60% | 3,285 | 474.62 | 474.62 | | 474.62 | - | 0.0% |
| 5 | 7.5 | 75% | 4,106 | 587.92 | 587.92 | | 587.92 | - | 0.0% |
| 10 | 12 | 15% | 1,314 | 202.63 | 202.63 | | 202.63 | - | 0.0% |
| 10 | 12 | 30% | 2,628 | 383.96 | 383.96 | | 383.96 | - | 0.0% |
| 10 | 12 | 45% | 3,942 | 565.29 | 565.29 | | 565.29 | - | 0.0% |
| 10 | 12 | 60% | 5,256 | 746.62 | 746.62 | | 746.62 | - | 0.0% |
| 10 | 12 | 75% | 6,570 | 927.95 | 927.95 | | 927.95 | - | 0.0% |
| 15 | 20 | 15% | 2,190 | 323.52 | 323.52 | | 323.52 | - | 0.0% |
| 15 | 20 | 30% | 4,380 | 625.73 | 625.73 | | 625.73 | - | 0.0% |
| 15 | 20 | 45% | 6,570 | 927.95 | 927.95 | | 927.95 | - | 0.0% |
| 15 | 20 | 60% | 8,760 | 1,146.83 | 1,146.83 | | 1,146.83 | - | 0.0% |
| 15 | 20 | 75% | 10,950 | 1,328.48 | 1,328.48 | | 1,328.48 | - | 0.0% |
| 20 | 25 | 15% | 2,738 | 399.14 | 399.14 | | 399.14 | - | 0.0% |
| 20 | 25 | 30% | 5,475 | 776.84 | 776.84 | | 776.84 | - | 0.0% |
| 20 | 25 | 45% | 8,213 | 1,101.46 | 1,101.46 | | 1,101.46 | - | 0.0% |
| 20 | 25 | 60% | 10,950 | 1,328.48 | 1,328.48 | | 1,328.48 | - | 0.0% |
| 20 | 25 | 75% | 13,688 | 1,555.58 | 1,555.58 | | 1,555.58 | - | 0.0% |

General Service TOU Average Energy On-Peak: 31%
Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 21 | 30 | 15% | 3,285 | 636.39 | 636.39 | | 636.39 | - | 0.0% |
| 21 | 30 | 30% | 6,570 | 785.96 | 785.96 | | 785.96 | - | 0.0% |
| 21 | 30 | 45% | 9,855 | 935.53 | 935.53 | | 935.53 | - | 0.0% |
| 21 | 30 | 60% | 13,140 | 1,085.10 | 1,085.10 | | 1,085.10 | - | 0.0% |
| 21 | 30 | 75% | 16,425 | 1,234.66 | 1,234.66 | | 1,234.66 | - | 0.0% |
| | | | | | - | | | | |
| 40 | 50 | 15% | 5,475 | 1,118.06 | 1,118.06 | | 1,118.06 | - | 0.0% |
| 40 | 50 | 30% | 10,950 | 1,367.34 | 1,367.34 | | 1,367.34 | - | 0.0% |
| 40 | 50 | 45% | 16,425 | 1,616.62 | 1,616.62 | | 1,616.62 | - | 0.0% |
| 40 | 50 | 60% | 21,900 | 1,865.90 | 1,865.90 | | 1,865.90 | - | 0.0% |
| 40 | 50 | 75% | 27,375 | 2,115.18 | 2,115.18 | | 2,115.18 | - | 0.0% |
| | | | | | - | | | | |
| 60 | 70 | 15% | 7,665 | 1,614.05 | 1,614.05 | | 1,614.05 | - | 0.0% |
| 60 | 70 | 30% | 15,330 | 1,963.05 | 1,963.05 | | 1,963.05 | - | 0.0% |
| 60 | 70 | 45% | 22,995 | 2,312.04 | 2,312.04 | | 2,312.04 | - | 0.0% |
| 60 | 70 | 60% | 30,660 | 2,661.03 | 2,661.03 | | 2,661.03 | - | 0.0% |
| 60 | 70 | 75% | 38,325 | 3,010.02 | 3,010.02 | | 3,010.02 | - | 0.0% |
| | | | | | - | | | | |
| 80 | 100 | 15% | 10,950 | 2,214.82 | 2,214.82 | | 2,214.82 | - | 0.0% |
| 80 | 100 | 30% | 21,900 | 2,713.38 | 2,713.38 | | 2,713.38 | - | 0.0% |
| 80 | 100 | 45% | 32,850 | 3,211.94 | 3,211.94 | | 3,211.94 | - | 0.0% |
| 80 | 100 | 60% | 43,800 | 3,710.50 | 3,710.50 | | 3,710.50 | - | 0.0% |
| 80 | 100 | 75% | 54,750 | 4,209.07 | 4,209.07 | | 4,209.07 | - | 0.0% |
| | | | | | - | | | | |
| 90 | 110 | 15% | 12,045 | 2,438.49 | 2,438.49 | | 2,438.49 | - | 0.0% |
| 90 | 110 | 30% | 24,090 | 2,986.90 | 2,986.90 | | 2,986.90 | - | 0.0% |
| 90 | 110 | 45% | 36,135 | 3,535.32 | 3,535.32 | | 3,535.32 | - | 0.0% |
| 90 | 110 | 60% | 48,180 | 4,083.74 | 4,083.74 | | 4,083.74 | - | 0.0% |
| 90 | 110 | 75% | 60,225 | 4,632.16 | 4,632.16 | | 4,632.16 | - | 0.0% |
| | | | | | - | | | | |
| 100 | 120 | 15% | 13,140 | 2,662.15 | 2,662.15 | | 2,662.15 | - | 0.0% |
| 100 | 120 | 30% | 26,280 | 3,260.43 | 3,260.43 | | 3,260.43 | - | 0.0% |
| 100 | 120 | 45% | 39,420 | 3,858.70 | 3,858.70 | | 3,858.70 | - | 0.0% |
| 100 | 120 | 60% | 52,560 | 4,456.97 | 4,456.97 | | 4,456.97 | - | 0.0% |
| 100 | 120 | 75% | 65,700 | 5,055.25 | 5,055.25 | | 5,055.25 | - | 0.0% |

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 21 | 30 | 15% | 3,285 | 692.40 | 692.40 | | 692.40 | - | 0.0% |
| 21 | 30 | 30% | 6,570 | 897.98 | 897.98 | | 897.98 | - | 0.0% |
| 21 | 30 | 45% | 9,855 | 1,103.55 | 1,103.55 | | 1,103.55 | - | 0.0% |
| 21 | 30 | 60% | 13,140 | 1,309.13 | 1,309.13 | | 1,309.13 | - | 0.0% |
| 21 | 30 | 75% | 16,425 | 1,514.71 | 1,514.71 | | 1,514.71 | - | 0.0% |
| | | | | | - | | | | |
| 40 | 50 | 15% | 5,475 | 1,211.41 | 1,211.41 | | 1,211.41 | - | 0.0% |
| 40 | 50 | 30% | 10,950 | 1,554.04 | 1,554.04 | | 1,554.04 | - | 0.0% |
| 40 | 50 | 45% | 16,425 | 1,896.67 | 1,896.67 | | 1,896.67 | - | 0.0% |
| 40 | 50 | 60% | 21,900 | 2,239.30 | 2,239.30 | | 2,239.30 | - | 0.0% |
| 40 | 50 | 75% | 27,375 | 2,581.93 | 2,581.93 | | 2,581.93 | - | 0.0% |
| | | | | | - | | | | |
| 60 | 70 | 15% | 7,665 | 1,744.74 | 1,744.74 | | 1,744.74 | - | 0.0% |
| 60 | 70 | 30% | 15,330 | 2,224.42 | 2,224.42 | | 2,224.42 | - | 0.0% |
| 60 | 70 | 45% | 22,995 | 2,704.10 | 2,704.10 | | 2,704.10 | - | 0.0% |
| 60 | 70 | 60% | 30,660 | 3,183.78 | 3,183.78 | | 3,183.78 | - | 0.0% |
| 60 | 70 | 75% | 38,325 | 3,663.47 | 3,663.47 | | 3,663.47 | - | 0.0% |
| | | | | | - | | | | |
| 80 | 100 | 15% | 10,950 | 2,401.52 | 2,401.52 | | 2,401.52 | - | 0.0% |
| 80 | 100 | 30% | 21,900 | 3,086.78 | 3,086.78 | | 3,086.78 | - | 0.0% |
| 80 | 100 | 45% | 32,850 | 3,772.04 | 3,772.04 | | 3,772.04 | - | 0.0% |
| 80 | 100 | 60% | 43,800 | 4,457.29 | 4,457.29 | | 4,457.29 | - | 0.0% |
| 80 | 100 | 75% | 54,750 | 5,142.55 | 5,142.55 | | 5,142.55 | - | 0.0% |
| | | | | | - | | | | |
| 90 | 110 | 15% | 12,045 | 2,643.85 | 2,643.85 | | 2,643.85 | - | 0.0% |
| 90 | 110 | 30% | 24,090 | 3,397.64 | 3,397.64 | | 3,397.64 | - | 0.0% |
| 90 | 110 | 45% | 36,135 | 4,151.42 | 4,151.42 | | 4,151.42 | - | 0.0% |
| 90 | 110 | 60% | 48,180 | 4,905.21 | 4,905.21 | | 4,905.21 | - | 0.0% |
| 90 | 110 | 75% | 60,225 | 5,658.99 | 5,658.99 | | 5,658.99 | - | 0.0% |
| | | | | | - | | | | |
| 100 | 120 | 15% | 13,140 | 2,886.19 | 2,886.19 | | 2,886.19 | - | 0.0% |
| 100 | 120 | 30% | 26,280 | 3,708.50 | 3,708.50 | | 3,708.50 | - | 0.0% |
| 100 | 120 | 45% | 39,420 | 4,530.81 | 4,530.81 | | 4,530.81 | - | 0.0% |
| 100 | 120 | 60% | 52,560 | 5,353.12 | 5,353.12 | | 5,353.12 | - | 0.0% |
| 100 | 120 | 75% | 65,700 | 6,175.43 | 6,175.43 | | 6,175.43 | - | 0.0% |

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 101 | 120 | 15% | 13,140 | 2,669.43 | 2,669.43 | | 2,669.43 | - | 0.0% |
| 101 | 120 | 30% | 26,280 | 3,263.01 | 3,263.01 | | 3,263.01 | - | 0.0% |
| 101 | 120 | 45% | 39,420 | 3,856.59 | 3,856.59 | | 3,856.59 | - | 0.0% |
| 101 | 120 | 60% | 52,560 | 4,450.17 | 4,450.17 | | 4,450.17 | - | 0.0% |
| 101 | 120 | 75% | 65,700 | 5,043.75 | 5,043.75 | | 5,043.75 | - | 0.0% |
| 150 | 170 | 15% | 18,615 | 3,541.25 | 3,541.25 | | 3,541.25 | - | 0.0% |
| 150 | 170 | 30% | 37,230 | 4,382.16 | 4,382.16 | | 4,382.16 | - | 0.0% |
| 150 | 170 | 45% | 55,845 | 5,223.06 | 5,223.06 | | 5,223.06 | - | 0.0% |
| 150 | 170 | 60% | 74,460 | 6,063.97 | 6,063.97 | | 6,063.97 | - | 0.0% |
| 150 | 170 | 75% | 93,075 | 6,904.87 | 6,904.87 | | 6,904.87 | - | 0.0% |
| 200 | 220 | 15% | 24,090 | 4,422.73 | 4,422.73 | | 4,422.73 | - | 0.0% |
| 200 | 220 | 30% | 48,180 | 5,510.96 | 5,510.96 | | 5,510.96 | - | 0.0% |
| 200 | 220 | 45% | 72,270 | 6,599.19 | 6,599.19 | | 6,599.19 | - | 0.0% |
| 200 | 220 | 60% | 96,360 | 7,687.42 | 7,687.42 | | 7,687.42 | - | 0.0% |
| 200 | 220 | 75% | 120,450 | 8,775.65 | 8,775.65 | | 8,775.65 | - | 0.0% |
| 300 | 320 | 15% | 35,040 | 6,185.68 | 6,185.68 | | 6,185.68 | - | 0.0% |
| 300 | 320 | 30% | 70,080 | 7,768.56 | 7,768.56 | | 7,768.56 | - | 0.0% |
| 300 | 320 | 45% | 105,120 | 9,351.44 | 9,351.44 | | 9,351.44 | - | 0.0% |
| 300 | 320 | 60% | 140,160 | 10,934.32 | 10,934.32 | | 10,934.32 | - | 0.0% |
| 300 | 320 | 75% | 175,200 | 12,517.20 | 12,517.20 | | 12,517.20 | - | 0.0% |
| 350 | 370 | 15% | 40,515 | 7,067.15 | 7,067.15 | | 7,067.15 | - | 0.0% |
| 350 | 370 | 30% | 81,030 | 8,897.36 | 8,897.36 | | 8,897.36 | - | 0.0% |
| 350 | 370 | 45% | 121,545 | 10,727.56 | 10,727.56 | | 10,727.56 | - | 0.0% |
| 350 | 370 | 60% | 162,060 | 12,557.77 | 12,557.77 | | 12,557.77 | - | 0.0% |
| 350 | 370 | 75% | 202,575 | 14,387.97 | 14,387.97 | | 14,387.97 | - | 0.0% |
| 400 | 420 | 15% | 45,990 | 7,948.63 | 7,948.63 | | 7,948.63 | - | 0.0% |
| 400 | 420 | 30% | 91,980 | 10,026.16 | 10,026.16 | | 10,026.16 | - | 0.0% |
| 400 | 420 | 45% | 137,970 | 12,103.69 | 12,103.69 | | 12,103.69 | - | 0.0% |
| 400 | 420 | 60% | 183,960 | 14,181.22 | 14,181.22 | | 14,181.22 | - | 0.0% |
| 400 | 420 | 75% | 229,950 | 16,258.75 | 16,258.75 | | 16,258.75 | - | 0.0% |

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 101 | 120 | 15% | 13,140 | 2,891.63 | 2,891.63 | | 2,891.63 | - | 0.0% |
| 101 | 120 | 30% | 26,280 | 3,707.40 | 3,707.40 | | 3,707.40 | - | 0.0% |
| 101 | 120 | 45% | 39,420 | 4,523.18 | 4,523.18 | | 4,523.18 | - | 0.0% |
| 101 | 120 | 60% | 52,560 | 5,338.96 | 5,338.96 | | 5,338.96 | - | 0.0% |
| 101 | 120 | 75% | 65,700 | 6,154.73 | 6,154.73 | | 6,154.73 | - | 0.0% |
| 150 | 170 | 15% | 18,615 | 3,856.03 | 3,856.03 | | 3,856.03 | - | 0.0% |
| 150 | 170 | 30% | 37,230 | 5,011.72 | 5,011.72 | | 5,011.72 | - | 0.0% |
| 150 | 170 | 45% | 55,845 | 6,167.40 | 6,167.40 | | 6,167.40 | - | 0.0% |
| 150 | 170 | 60% | 74,460 | 7,323.09 | 7,323.09 | | 7,323.09 | - | 0.0% |
| 150 | 170 | 75% | 93,075 | 8,478.77 | 8,478.77 | | 8,478.77 | - | 0.0% |
| 200 | 220 | 15% | 24,090 | 4,830.09 | 4,830.09 | | 4,830.09 | - | 0.0% |
| 200 | 220 | 30% | 48,180 | 6,325.68 | 6,325.68 | | 6,325.68 | - | 0.0% |
| 200 | 220 | 45% | 72,270 | 7,821.27 | 7,821.27 | | 7,821.27 | - | 0.0% |
| 200 | 220 | 60% | 96,360 | 9,316.87 | 9,316.87 | | 9,316.87 | - | 0.0% |
| 200 | 220 | 75% | 120,450 | 10,812.46 | 10,812.46 | | 10,812.46 | - | 0.0% |
| 300 | 320 | 15% | 35,040 | 6,778.21 | 6,778.21 | | 6,778.21 | - | 0.0% |
| 300 | 320 | 30% | 70,080 | 8,953.61 | 8,953.61 | | 8,953.61 | - | 0.0% |
| 300 | 320 | 45% | 105,120 | 11,129.02 | 11,129.02 | | 11,129.02 | - | 0.0% |
| 300 | 320 | 60% | 140,160 | 13,304.42 | 13,304.42 | | 13,304.42 | - | 0.0% |
| 300 | 320 | 75% | 175,200 | 15,479.83 | 15,479.83 | | 15,479.83 | - | 0.0% |
| 350 | 370 | 15% | 40,515 | 7,752.26 | 7,752.26 | | 7,752.26 | - | 0.0% |
| 350 | 370 | 30% | 81,030 | 10,267.58 | 10,267.58 | | 10,267.58 | - | 0.0% |
| 350 | 370 | 45% | 121,545 | 12,782.89 | 12,782.89 | | 12,782.89 | - | 0.0% |
| 350 | 370 | 60% | 162,060 | 15,298.20 | 15,298.20 | | 15,298.20 | - | 0.0% |
| 350 | 370 | 75% | 202,575 | 17,813.52 | 17,813.52 | | 17,813.52 | - | 0.0% |
| 400 | 420 | 15% | 45,990 | 8,726.32 | 8,726.32 | | 8,726.32 | - | 0.0% |
| 400 | 420 | 30% | 91,980 | 11,581.54 | 11,581.54 | | 11,581.54 | - | 0.0% |
| 400 | 420 | 45% | 137,970 | 14,436.76 | 14,436.76 | | 14,436.76 | - | 0.0% |
| 400 | 420 | 60% | 183,960 | 17,291.98 | 17,291.98 | | 17,291.98 | - | 0.0% |
| 400 | 420 | 75% | 229,950 | 20,147.20 | 20,147.20 | | 20,147.20 | - | 0.0% |

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) *Present Rates are rates effective 1/1/2010.*
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | 7,950.15 | 7,950.15 | | 7,950.15 | - | 0.0% |
| 401 | 441 | 30% | 96,579 | 10,083.76 | 10,083.76 | | 10,083.76 | - | 0.0% |
| 401 | 441 | 45% | 144,869 | 12,217.42 | 12,217.42 | | 12,217.42 | - | 0.0% |
| 401 | 441 | 60% | 193,158 | 14,351.04 | 14,351.04 | | 14,351.04 | - | 0.0% |
| 401 | 441 | 75% | 241,448 | 16,484.70 | 16,484.70 | | 16,484.70 | - | 0.0% |
| 600 | 640 | 15% | 70,080 | 11,382.12 | 11,382.12 | | 11,382.12 | - | 0.0% |
| 600 | 640 | 30% | 140,160 | 14,478.55 | 14,478.55 | | 14,478.55 | - | 0.0% |
| 600 | 640 | 45% | 210,240 | 17,574.99 | 17,574.99 | | 17,574.99 | - | 0.0% |
| 600 | 640 | 60% | 280,320 | 20,671.42 | 20,671.42 | | 20,671.42 | - | 0.0% |
| 600 | 640 | 75% | 350,400 | 23,767.86 | 23,767.86 | | 23,767.86 | - | 0.0% |
| 800 | 860 | 15% | 94,170 | 14,987.50 | 14,987.50 | | 14,987.50 | - | 0.0% |
| 800 | 860 | 30% | 188,340 | 19,148.33 | 19,148.33 | | 19,148.33 | - | 0.0% |
| 800 | 860 | 45% | 282,510 | 23,309.17 | 23,309.17 | | 23,309.17 | - | 0.0% |
| 800 | 860 | 60% | 376,680 | 27,470.00 | 27,470.00 | | 27,470.00 | - | 0.0% |
| 800 | 860 | 75% | 470,850 | 31,630.84 | 31,630.84 | | 31,630.84 | - | 0.0% |
| 1,000 | 1,200 | 15% | 131,400 | 19,529.74 | 19,529.74 | | 19,529.74 | - | 0.0% |
| 1,000 | 1,200 | 30% | 262,800 | 25,335.55 | 25,335.55 | | 25,335.55 | - | 0.0% |
| 1,000 | 1,200 | 45% | 394,200 | 31,141.37 | 31,141.37 | | 31,141.37 | - | 0.0% |
| 1,000 | 1,200 | 60% | 525,600 | 36,947.19 | 36,947.19 | | 36,947.19 | - | 0.0% |
| 1,000 | 1,200 | 75% | 657,000 | 42,753.01 | 42,753.01 | | 42,753.01 | - | 0.0% |
| 1,500 | 1,700 | 15% | 186,150 | 28,152.83 | 28,152.83 | | 28,152.83 | - | 0.0% |
| 1,500 | 1,700 | 30% | 372,300 | 36,377.73 | 36,377.73 | | 36,377.73 | - | 0.0% |
| 1,500 | 1,700 | 45% | 558,450 | 44,602.64 | 44,602.64 | | 44,602.64 | - | 0.0% |
| 1,500 | 1,700 | 60% | 744,600 | 52,827.55 | 52,827.55 | | 52,827.55 | - | 0.0% |
| 1,500 | 1,700 | 75% | 930,750 | 61,052.46 | 61,052.46 | | 61,052.46 | - | 0.0% |
| 3,000 | 3,200 | 15% | 350,400 | 54,022.10 | 54,022.10 | | 54,022.10 | - | 0.0% |
| 3,000 | 3,200 | 30% | 700,800 | 69,504.28 | 69,504.28 | | 69,504.28 | - | 0.0% |
| 3,000 | 3,200 | 45% | 1,051,200 | 84,986.46 | 84,986.46 | | 84,986.46 | - | 0.0% |
| 3,000 | 3,200 | 60% | 1,401,600 | 100,468.63 | 100,468.63 | | 100,468.63 | - | 0.0% |
| 3,000 | 3,200 | 75% | 1,752,000 | 115,950.81 | 115,950.81 | | 115,950.81 | - | 0.0% |

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 401 | 441 | 15% | 48,290 | 8,749.35 | 8,749.35 | | 8,749.35 | - | 0.0% |
| 401 | 441 | 30% | 96,579 | 11,682.15 | 11,682.15 | | 11,682.15 | - | 0.0% |
| 401 | 441 | 45% | 144,869 | 14,615.01 | 14,615.01 | | 14,615.01 | - | 0.0% |
| 401 | 441 | 60% | 193,158 | 17,547.80 | 17,547.80 | | 17,547.80 | - | 0.0% |
| 401 | 441 | 75% | 241,448 | 20,480.66 | 20,480.66 | | 20,480.66 | - | 0.0% |
| | | | | | - | | | | |
| 600 | 640 | 15% | 70,080 | 12,541.94 | 12,541.94 | | 12,541.94 | - | 0.0% |
| 600 | 640 | 30% | 140,160 | 16,798.20 | 16,798.20 | | 16,798.20 | - | 0.0% |
| 600 | 640 | 45% | 210,240 | 21,054.46 | 21,054.46 | | 21,054.46 | - | 0.0% |
| 600 | 640 | 60% | 280,320 | 25,310.72 | 25,310.72 | | 25,310.72 | - | 0.0% |
| 600 | 640 | 75% | 350,400 | 29,566.98 | 29,566.98 | | 29,566.98 | - | 0.0% |
| | | | | | - | | | | |
| 800 | 860 | 15% | 94,170 | 16,546.01 | 16,546.01 | | 16,546.01 | - | 0.0% |
| 800 | 860 | 30% | 188,340 | 22,265.36 | 22,265.36 | | 22,265.36 | - | 0.0% |
| 800 | 860 | 45% | 282,510 | 27,984.71 | 27,984.71 | | 27,984.71 | - | 0.0% |
| 800 | 860 | 60% | 376,680 | 33,704.06 | 33,704.06 | | 33,704.06 | - | 0.0% |
| 800 | 860 | 75% | 470,850 | 39,423.41 | 39,423.41 | | 39,423.41 | - | 0.0% |
| | | | | | - | | | | |
| 1,000 | 1,200 | 15% | 131,400 | 21,704.41 | 21,704.41 | | 21,704.41 | - | 0.0% |
| 1,000 | 1,200 | 30% | 262,800 | 29,684.89 | 29,684.89 | | 29,684.89 | - | 0.0% |
| 1,000 | 1,200 | 45% | 394,200 | 37,665.38 | 37,665.38 | | 37,665.38 | - | 0.0% |
| 1,000 | 1,200 | 60% | 525,600 | 45,645.87 | 45,645.87 | | 45,645.87 | - | 0.0% |
| 1,000 | 1,200 | 75% | 657,000 | 53,626.36 | 53,626.36 | | 53,626.36 | - | 0.0% |
| | | | | | - | | | | |
| 1,500 | 1,700 | 15% | 186,150 | 31,233.61 | 31,233.61 | | 31,233.61 | - | 0.0% |
| 1,500 | 1,700 | 30% | 372,300 | 42,539.30 | 42,539.30 | | 42,539.30 | - | 0.0% |
| 1,500 | 1,700 | 45% | 558,450 | 53,844.99 | 53,844.99 | | 53,844.99 | - | 0.0% |
| 1,500 | 1,700 | 60% | 744,600 | 65,150.68 | 65,150.68 | | 65,150.68 | - | 0.0% |
| 1,500 | 1,700 | 75% | 930,750 | 76,456.37 | 76,456.37 | | 76,456.37 | - | 0.0% |
| | | | | | - | | | | |
| 3,000 | 3,200 | 15% | 350,400 | 59,821.22 | 59,821.22 | | 59,821.22 | - | 0.0% |
| 3,000 | 3,200 | 30% | 700,800 | 81,102.52 | 81,102.52 | | 81,102.52 | - | 0.0% |
| 3,000 | 3,200 | 45% | 1,051,200 | 102,383.82 | 102,383.82 | | 102,383.82 | - | 0.0% |
| 3,000 | 3,200 | 60% | 1,401,600 | 123,665.11 | 123,665.11 | | 123,665.11 | - | 0.0% |
| 3,000 | 3,200 | 75% | 1,752,000 | 144,946.41 | 144,946.41 | | 144,946.41 | - | 0.0% |

E-32TOU On-Peak Split: 31%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 3,000 | 20% | 438,000 | 70,667.88 | 70,667.88 | | 70,667.88 | - | 0.0% |
| 3,000 | 30% | 657,000 | 79,909.68 | 79,909.68 | | 79,909.68 | - | 0.0% |
| 3,000 | 40% | 876,000 | 89,151.48 | 89,151.48 | | 89,151.48 | - | 0.0% |
| 3,000 | 50% | 1,095,000 | 98,393.28 | 98,393.28 | | 98,393.28 | - | 0.0% |
| 3,000 | 75% | 1,642,500 | 121,497.78 | 121,497.78 | | 121,497.78 | - | 0.0% |
| | | | | - | | | | |
| 3,500 | 20% | 511,000 | 82,436.98 | 82,436.98 | | 82,436.98 | - | 0.0% |
| 3,500 | 30% | 766,500 | 93,219.08 | 93,219.08 | | 93,219.08 | - | 0.0% |
| 3,500 | 40% | 1,022,000 | 104,001.18 | 104,001.18 | | 104,001.18 | - | 0.0% |
| 3,500 | 50% | 1,277,500 | 114,783.28 | 114,783.28 | | 114,783.28 | - | 0.0% |
| 3,500 | 75% | 1,916,250 | 141,738.53 | 141,738.53 | | 141,738.53 | - | 0.0% |
| | | | | - | | | | |
| 4,000 | 20% | 584,000 | 94,206.08 | 94,206.08 | | 94,206.08 | - | 0.0% |
| 4,000 | 30% | 876,000 | 106,528.48 | 106,528.48 | | 106,528.48 | - | 0.0% |
| 4,000 | 40% | 1,168,000 | 118,850.88 | 118,850.88 | | 118,850.88 | - | 0.0% |
| 4,000 | 50% | 1,460,000 | 131,173.28 | 131,173.28 | | 131,173.28 | - | 0.0% |
| 4,000 | 75% | 2,190,000 | 161,979.28 | 161,979.28 | | 161,979.28 | - | 0.0% |
| | | | | - | | | | |
| 4,500 | 20% | 657,000 | 105,975.18 | 105,975.18 | | 105,975.18 | - | 0.0% |
| 4,500 | 30% | 985,500 | 119,837.88 | 119,837.88 | | 119,837.88 | - | 0.0% |
| 4,500 | 40% | 1,314,000 | 133,700.58 | 133,700.58 | | 133,700.58 | - | 0.0% |
| 4,500 | 50% | 1,642,500 | 147,563.28 | 147,563.28 | | 147,563.28 | - | 0.0% |
| 4,500 | 75% | 2,463,750 | 182,220.03 | 182,220.03 | | 182,220.03 | - | 0.0% |
| | | | | - | | | | |
| 5,000 | 20% | 730,000 | 117,744.28 | 117,744.28 | | 117,744.28 | - | 0.0% |
| 5,000 | 30% | 1,095,000 | 133,147.28 | 133,147.28 | | 133,147.28 | - | 0.0% |
| 5,000 | 40% | 1,460,000 | 148,550.28 | 148,550.28 | | 148,550.28 | - | 0.0% |
| 5,000 | 50% | 1,825,000 | 163,953.28 | 163,953.28 | | 163,953.28 | - | 0.0% |
| 5,000 | 75% | 2,737,500 | 202,460.78 | 202,460.78 | | 202,460.78 | - | 0.0% |
| | | | | - | | | | |
| 6,000 | 20% | 876,000 | 141,282.48 | 141,282.48 | | 141,282.48 | - | 0.0% |
| 6,000 | 30% | 1,314,000 | 159,766.08 | 159,766.08 | | 159,766.08 | - | 0.0% |
| 6,000 | 40% | 1,752,000 | 178,249.68 | 178,249.68 | | 178,249.68 | - | 0.0% |
| 6,000 | 50% | 2,190,000 | 196,733.28 | 196,733.28 | | 196,733.28 | - | 0.0% |
| 6,000 | 75% | 3,285,000 | 242,942.28 | 242,942.28 | | 242,942.28 | - | 0.0% |
| | | | | - | | | | |
| 7,000 | 20% | 1,022,000 | 164,820.68 | 164,820.68 | | 164,820.68 | - | 0.0% |
| 7,000 | 30% | 1,533,000 | 186,384.88 | 186,384.88 | | 186,384.88 | - | 0.0% |
| 7,000 | 50% | 2,555,000 | 229,513.28 | 229,513.28 | | 229,513.28 | - | 0.0% |
| 7,000 | 75% | 3,832,500 | 283,423.78 | 283,423.78 | | 283,423.78 | - | 0.0% |

Unbundled Transmission Charge (>=3,000 kW): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

Arizona Public Service Company
Test Year Ending December 2010
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) |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| On-Peak kW | Off-Peak kW | Load Factor | Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 3,000 | 4,000 | 20% | 438,000 | 73,253.75 | 73,253.75 | | 73,253.75 | - | 0.0% |
| 3,000 | 4,000 | 30% | 657,000 | 81,749.19 | 81,749.19 | | 81,749.19 | - | 0.0% |
| 3,000 | 4,000 | 40% | 876,000 | 90,244.64 | 90,244.64 | | 90,244.64 | - | 0.0% |
| 3,000 | 4,000 | 50% | 1,095,000 | 98,740.09 | 98,740.09 | | 98,740.09 | - | 0.0% |
| 3,000 | 4,000 | 75% | 1,642,500 | 119,978.71 | 119,978.71 | | 119,978.71 | - | 0.0% |
| | | | | | - | | | | |
| 3,500 | 4,500 | 20% | 511,000 | 84,998.06 | 84,998.06 | | 84,998.06 | - | 0.0% |
| 3,500 | 4,500 | 30% | 766,500 | 94,909.42 | 94,909.42 | | 94,909.42 | - | 0.0% |
| 3,500 | 4,500 | 40% | 1,022,000 | 104,820.77 | 104,820.77 | | 104,820.77 | - | 0.0% |
| 3,500 | 4,500 | 50% | 1,277,500 | 114,732.13 | 114,732.13 | | 114,732.13 | - | 0.0% |
| 3,500 | 4,500 | 75% | 1,916,250 | 139,510.52 | 139,510.52 | | 139,510.52 | - | 0.0% |
| | | | | | - | | | | |
| 4,000 | 5,000 | 20% | 584,000 | 96,742.38 | 96,742.38 | | 96,742.38 | - | 0.0% |
| 4,000 | 5,000 | 30% | 876,000 | 108,069.64 | 108,069.64 | | 108,069.64 | - | 0.0% |
| 4,000 | 5,000 | 40% | 1,168,000 | 119,396.91 | 119,396.91 | | 119,396.91 | - | 0.0% |
| 4,000 | 5,000 | 50% | 1,460,000 | 130,724.17 | 130,724.17 | | 130,724.17 | - | 0.0% |
| 4,000 | 5,000 | 75% | 2,190,000 | 159,042.33 | 159,042.33 | | 159,042.33 | - | 0.0% |
| | | | | | - | | | | |
| 4,500 | 6,000 | 20% | 657,000 | 109,853.69 | 109,853.69 | | 109,853.69 | - | 0.0% |
| 4,500 | 6,000 | 30% | 985,500 | 122,596.87 | 122,596.87 | | 122,596.87 | - | 0.0% |
| 4,500 | 6,000 | 40% | 1,314,000 | 135,340.04 | 135,340.04 | | 135,340.04 | - | 0.0% |
| 4,500 | 6,000 | 50% | 1,642,500 | 148,083.21 | 148,083.21 | | 148,083.21 | - | 0.0% |
| 4,500 | 6,000 | 75% | 2,463,750 | 179,941.14 | 179,941.14 | | 179,941.14 | - | 0.0% |
| | | | | | - | | | | |
| 5,000 | 7,000 | 20% | 730,000 | 122,965.01 | 122,965.01 | | 122,965.01 | - | 0.0% |
| 5,000 | 7,000 | 30% | 1,095,000 | 137,124.09 | 137,124.09 | | 137,124.09 | - | 0.0% |
| 5,000 | 7,000 | 40% | 1,460,000 | 151,283.17 | 151,283.17 | | 151,283.17 | - | 0.0% |
| 5,000 | 7,000 | 50% | 1,825,000 | 165,442.25 | 165,442.25 | | 165,442.25 | - | 0.0% |
| 5,000 | 7,000 | 75% | 2,737,500 | 200,839.95 | 200,839.95 | | 200,839.95 | - | 0.0% |
| | | | | | - | | | | |
| 6,000 | 8,000 | 20% | 876,000 | 146,453.64 | 146,453.64 | | 146,453.64 | - | 0.0% |
| 6,000 | 8,000 | 30% | 1,314,000 | 163,444.54 | 163,444.54 | | 163,444.54 | - | 0.0% |
| 6,000 | 8,000 | 40% | 1,752,000 | 180,435.43 | 180,435.43 | | 180,435.43 | - | 0.0% |
| 6,000 | 8,000 | 50% | 2,190,000 | 197,426.33 | 197,426.33 | | 197,426.33 | - | 0.0% |
| 6,000 | 8,000 | 75% | 3,285,000 | 239,903.57 | 239,903.57 | | 239,903.57 | - | 0.0% |
| | | | | | - | | | | |
| 7,000 | 8,500 | 20% | 1,022,000 | 168,575.27 | 168,575.27 | | 168,575.27 | - | 0.0% |
| 7,000 | 8,500 | 30% | 1,533,000 | 188,397.99 | 188,397.99 | | 188,397.99 | - | 0.0% |
| 7,000 | 8,500 | 50% | 2,555,000 | 228,043.41 | 228,043.41 | | 228,043.41 | - | 0.0% |
| 7,000 | 8,500 | 75% | 3,832,500 | 277,600.19 | 277,600.19 | | 277,600.19 | - | 0.0% |

E-35 Average Energy On-Peak: 30%
Unbundled Transmission Charge (>=3,000 kW): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| HPS, cobra / roadway | 5,800 | 29 | Company | 8.73 | 8.73 | | 8.73 | - | 0.0% |
| | | 29 | Customer | 5.16 | 5.16 | | 5.16 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 9,500 | 41 | Company | 10.28 | 10.28 | | 10.28 | - | 0.0% |
| | | 41 | Customer | 6.32 | 6.32 | | 6.32 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 9,500 | 41 | Company | 15.38 | 15.38 | | 15.38 | - | 0.0% |
| | | 41 | Customer | 7.34 | 7.34 | | 7.34 | - | 0.0% |
| | | | | | - | | | | |
| HPS, acorn luminaire | 9,500 | 41 | Company | 27.06 | 27.06 | | 27.06 | - | 0.0% |
| | | 41 | Customer | 9.22 | 9.22 | | 9.22 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 16,000 | 69 | Company | 12.87 | 12.87 | | 12.87 | - | 0.0% |
| | | 69 | Customer | 8.82 | 8.82 | | 8.82 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 16,000 | 69 | Company | 17.96 | 17.96 | | 17.96 | - | 0.0% |
| | | 69 | Customer | 9.82 | 9.82 | | 9.82 | - | 0.0% |
| | | | | | - | | | | |
| HPS, acorn luminaire | 16,000 | 69 | Company | 30.04 | 30.04 | | 30.04 | - | 0.0% |
| | | 69 | Customer | 11.65 | 11.65 | | 11.65 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 30,000 | 99 | Company | 15.52 | 15.52 | | 15.52 | - | 0.0% |
| | | 99 | Customer | 11.46 | 11.46 | | 11.46 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 30,000 | 99 | Company | 21.31 | 21.31 | | 21.31 | - | 0.0% |
| | | 99 | Customer | 12.60 | 12.60 | | 12.60 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 50,000 | 153 | Company | 21.06 | 21.06 | | 21.06 | - | 0.0% |
| | | 153 | Customer | 16.37 | 16.37 | | 16.37 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 50,000 | 153 | Company | 26.29 | 26.29 | | 26.29 | - | 0.0% |
| | | 153 | Customer | 18.13 | 18.13 | | 18.13 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 8,000 | 30 | Company | 22.35 | 22.35 | | 22.35 | - | 0.0% |
| | | 30 | Customer | 9.82 | 9.82 | | 9.82 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 13,500 | 50 | Company | 26.36 | 26.36 | | 26.36 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 22,500 | 72 | Company | 30.11 | 30.11 | | 30.11 | - | 0.0% |
| | | 72 | Customer | 14.45 | 14.45 | | 14.45 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 33,000 | 90 | Company | 36.22 | 36.22 | | 36.22 | - | 0.0% |
| | | 90 | Customer | 17.02 | 17.02 | | 17.02 | - | 0.0% |
| | | | | | - | | | | |
| Type of Pole | Height | Desc. | | | - | | | | |
| | | | | | - | | | | |
| Direct Bury | 30 FT | Round | Company | 14.38 | 14.38 | | 14.38 | - | 0.0% |
| | | Steel | Customer | N/A | N/A | | | | N/A |
| | | | | | - | | | | |
| Direct Bury | 34 FT | Square | Company | 15.87 | 15.87 | | 15.87 | - | 0.0% |
| | | Steel | Customer | N/A | N/A | | | | N/A |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| HPS, cobra / roadway | 5,800 | 29 | Inv. By Co. | 8.73 | 8.73 | | 8.73 | - | 0.0% |
| | | 29 | Inv. By Others | 5.16 | 5.16 | | 5.16 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 9,500 | 41 | Inv. By Co. | 10.28 | 10.28 | | 10.28 | - | 0.0% |
| | | 41 | Inv. By Others | 6.32 | 6.32 | | 6.32 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 9,500 | 41 | Inv. By Co. | 15.38 | 15.38 | | 15.38 | - | 0.0% |
| | | 41 | Inv. By Others | 7.34 | 7.34 | | 7.34 | - | 0.0% |
| | | | | | - | | | | |
| HPS, acorn luminaire | 9,500 | 41 | Inv. By Co. | 27.06 | 27.06 | | 27.06 | - | 0.0% |
| | | 41 | Inv. By Others | 9.22 | 9.22 | | 9.22 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 16,000 | 69 | Inv. By Co. | 12.87 | 12.87 | | 12.87 | - | 0.0% |
| | | 69 | Inv. By Others | 8.82 | 8.82 | | 8.82 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 16,000 | 69 | Inv. By Co. | 17.96 | 17.96 | | 17.96 | - | 0.0% |
| | | 69 | Inv. By Others | 9.82 | 9.82 | | 9.82 | - | 0.0% |
| | | | | | - | | | | |
| HPS, acorn luminaire | 16,000 | 69 | Inv. By Co. | 30.04 | 30.04 | | 30.04 | - | 0.0% |
| | | 69 | Inv. By Others | 11.65 | 11.65 | | 11.65 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 30,000 | 99 | Inv. By Co. | 15.52 | 15.52 | | 15.52 | - | 0.0% |
| | | 99 | Inv. By Others | 11.46 | 11.46 | | 11.46 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 30,000 | 99 | Inv. By Co. | 21.31 | 21.31 | | 21.31 | - | 0.0% |
| | | 99 | Inv. By Others | 12.60 | 12.60 | | 12.60 | - | 0.0% |
| | | | | | - | | | | |
| HPS, cobra / roadway | 50,000 | 153 | Inv. By Co. | 21.06 | 21.06 | | 21.06 | - | 0.0% |
| | | 153 | Inv. By Others | 16.37 | 16.37 | | 16.37 | - | 0.0% |
| | | | | | - | | | | |
| HPS, architectural | 50,000 | 153 | Inv. By Co. | 26.29 | 26.29 | | 26.29 | - | 0.0% |
| | | 153 | Inv. By Others | 18.13 | 18.13 | | 18.13 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 8,000 | 30 | Inv. By Co. | 22.35 | 22.35 | | 22.35 | - | 0.0% |
| | | 30 | Inv. By Others | 9.82 | 9.82 | | 9.82 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 13,500 | 50 | Inv. By Co. | 26.36 | 26.36 | | 26.36 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 22,500 | 72 | Inv. By Co. | 30.11 | 30.11 | | 30.11 | - | 0.0% |
| | | 72 | Inv. By Others | 14.45 | 14.45 | | 14.45 | - | 0.0% |
| | | | | | - | | | | |
| LPS, architectural | 33,000 | 90 | Inv. By Co. | 36.22 | 36.22 | | 36.22 | - | 0.0% |
| | | 90 | Inv. By Others | 17.02 | 17.02 | | 17.02 | - | 0.0% |
| | | | | | - | | | | |
| Type of Pole | Height | Desc. | | | - | | | | |
| | | | | | - | | | | |
| Direct Bury | 30 FT | Round | Inv. By Co. | 14.38 | 14.38 | | 14.38 | - | 0.0% |
| | | Steel | Inv. By Others | 2.66 | 2.66 | | 2.66 | - | 0.0% |
| | | | | | - | | | | |
| Direct Bury | 34 FT | Square | Inv. By Co. | 15.87 | 15.87 | | 15.87 | - | 0.0% |
| | | Steel | Inv. By Others | 2.75 | 2.75 | | 2.75 | - | 0.0% |
| | | | | | - | | | | |
| Direct Bury | 38 FT | Square | Inv. By Co. | 17.05 | 17.05 | | 17.05 | - | 0.0% |
| | | Steel | Inv. By Others | 2.96 | 2.96 | | 2.96 | - | 0.0% |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|---|
| | | | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Lamps | kWh per Lamp | Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 50 | 30 | 1,500 | 230.82 | 230.82 | | 230.82 | - | 0.0% |
| 50 | 60 | 3,000 | 322.14 | 322.14 | | 322.14 | - | 0.0% |
| 50 | 75 | 3,750 | 367.80 | 367.80 | | 367.80 | - | 0.0% |
| 50 | 100 | 5,000 | 443.90 | 443.90 | | 443.90 | - | 0.0% |
| 50 | 150 | 7,500 | 596.10 | 596.10 | | 596.10 | - | 0.0% |
| | | | | - | | | | |
| 100 | 30 | 3,000 | 461.64 | 461.64 | | 461.64 | - | 0.0% |
| 100 | 60 | 6,000 | 644.28 | 644.28 | | 644.28 | - | 0.0% |
| 100 | 75 | 7,500 | 735.60 | 735.60 | | 735.60 | - | 0.0% |
| 100 | 100 | 10,000 | 887.80 | 887.80 | | 887.80 | - | 0.0% |
| 100 | 150 | 15,000 | 1,192.20 | 1,192.20 | | 1,192.20 | - | 0.0% |
| | | | | - | | | | |
| 200 | 30 | 6,000 | 923.28 | 923.28 | | 923.28 | - | 0.0% |
| 200 | 60 | 12,000 | 1,288.56 | 1,288.56 | | 1,288.56 | - | 0.0% |
| 200 | 75 | 15,000 | 1,471.20 | 1,471.20 | | 1,471.20 | - | 0.0% |
| 200 | 100 | 20,000 | 1,775.60 | 1,775.60 | | 1,775.60 | - | 0.0% |
| 200 | 150 | 30,000 | 2,384.40 | 2,384.40 | | 2,384.40 | - | 0.0% |
| | | | | - | | | | |
| 500 | 30 | 15,000 | 2,308.20 | 2,308.20 | | 2,308.20 | - | 0.0% |
| 500 | 60 | 30,000 | 3,221.40 | 3,221.40 | | 3,221.40 | - | 0.0% |
| 500 | 75 | 37,500 | 3,678.00 | 3,678.00 | | 3,678.00 | - | 0.0% |
| 500 | 100 | 50,000 | 4,439.00 | 4,439.00 | | 4,439.00 | - | 0.0% |
| 500 | 150 | 75,000 | 5,961.00 | 5,961.00 | | 5,961.00 | - | 0.0% |
| | | | | - | | | | |
| 1,000 | 30 | 30,000 | 4,616.40 | 4,616.40 | | 4,616.40 | - | 0.0% |
| 1,000 | 60 | 60,000 | 6,442.80 | 6,442.80 | | 6,442.80 | - | 0.0% |
| 1,000 | 75 | 75,000 | 7,356.00 | 7,356.00 | | 7,356.00 | - | 0.0% |
| 1,000 | 100 | 100,000 | 8,878.00 | 8,878.00 | | 8,878.00 | - | 0.0% |
| 1,000 | 150 | 150,000 | 11,922.00 | 11,922.00 | | 11,922.00 | - | 0.0% |
| | | | | - | | | | |
| 2,000 | 30 | 60,000 | 9,232.80 | 9,232.80 | | 9,232.80 | - | 0.0% |
| 2,000 | 60 | 120,000 | 12,885.60 | 12,885.60 | | 12,885.60 | - | 0.0% |
| 2,000 | 75 | 150,000 | 14,712.00 | 14,712.00 | | 14,712.00 | - | 0.0% |
| 2,000 | 100 | 200,000 | 17,756.00 | 17,756.00 | | 17,756.00 | - | 0.0% |
| 2,000 | 150 | 300,000 | 23,844.00 | 23,844.00 | | 23,844.00 | - | 0.0% |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|
| | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| Monthly kWh | under Present Rates | Base | Transmission | under Proposed Rates | Amount ($) | % |
| | | | | (C) + (D) | (E) - (B) | (F) / (B) |
| 30 | 1.56 | 1.56 | | 1.56 | - | 0.0% |
| 40 | 2.08 | 2.08 | | 2.08 | - | 0.0% |
| 50 | 2.60 | 2.60 | | 2.60 | - | 0.0% |
| 60 | 3.12 | 3.12 | | 3.12 | - | 0.0% |
| 70 | 3.64 | 3.64 | | 3.64 | - | 0.0% |
| 80 | 4.15 | 4.15 | | 4.15 | - | 0.0% |
| 90 | 4.67 | 4.67 | | 4.67 | - | 0.0% |
| 100 | 5.19 | 5.19 | | 5.19 | - | 0.0% |
| 125 | 6.49 | 6.49 | | 6.49 | - | 0.0% |
| 150 | 7.79 | 7.79 | | 7.79 | - | 0.0% |
| 175 | 9.09 | 9.09 | | 9.09 | - | 0.0% |
| 200 | 10.39 | 10.39 | | 10.39 | - | 0.0% |
| 225 | 11.68 | 11.68 | | 11.68 | - | 0.0% |
| 250 | 12.98 | 12.98 | | 12.98 | - | 0.0% |
| 275 | 14.28 | 14.28 | | 14.28 | - | 0.0% |
| 300 | 15.58 | 15.58 | | 15.58 | - | 0.0% |
| 325 | 16.88 | 16.88 | | 16.88 | - | 0.0% |
| 350 | 18.18 | 18.18 | | 18.18 | - | 0.0% |
| 375 | 19.47 | 19.47 | | 19.47 | - | 0.0% |
| 400 | 20.77 | 20.77 | | 20.77 | - | 0.0% |
| 425 | 22.07 | 22.07 | | 22.07 | - | 0.0% |
| 450 | 23.37 | 23.37 | | 23.37 | - | 0.0% |
| 475 | 24.67 | 24.67 | | 24.67 | - | 0.0% |
| 500 | 25.97 | 25.97 | | 25.97 | - | 0.0% |
| 600 | 31.16 | 31.16 | | 31.16 | - | 0.0% |
| 700 | 36.35 | 36.35 | | 36.35 | - | 0.0% |
| 800 | 41.54 | 41.54 | | 41.54 | - | 0.0% |
| 900 | 46.74 | 46.74 | | 46.74 | - | 0.0% |
| 1,000 | 51.93 | 51.93 | | 51.93 | - | 0.0% |
| 1,500 | 77.90 | 77.90 | | 77.90 | - | 0.0% |
| 2,000 | 103.86 | 103.86 | | 103.86 | - | 0.0% |
| 2,500 | 129.83 | 129.83 | | 129.83 | - | 0.0% |

Unbundled Transmission Charge (<=20 kW): $/kWh

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Ta:
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Classified 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) |
|---|---|---|---|---|---|---|---|---|
| | | | Monthly Bill | Components of Proposed Bill | | Monthly Bill | Change | |
| | Load | Monthly | under | | | under | | |
| kW | Factor | kWh | Present Rates | Base | Transmission | Proposed Rates | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 10 | 20% | 1,460 | 160.44 | 160.44 | | 160.44 | 0.00 | 0.0% |
| 10 | 35% | 2,555 | 247.38 | 247.38 | | 247.38 | 0.00 | 0.0% |
| 10 | 50% | 3,650 | 324.95 | 324.95 | | 324.95 | 0.00 | 0.0% |
| 10 | 65% | 4,745 | 396.33 | 396.33 | | 396.33 | 0.00 | 0.0% |
| 10 | 80% | 5,840 | 467.71 | 467.71 | | 467.71 | 0.00 | 0.0% |
| | | | | 0.00 | | | | |
| 30 | 20% | 4,380 | 429.89 | 429.89 | | 429.89 | 0.00 | 0.0% |
| 30 | 35% | 7,665 | 690.72 | 690.72 | | 690.72 | 0.00 | 0.0% |
| 30 | 50% | 10,950 | 916.59 | 916.59 | | 916.59 | 0.00 | 0.0% |
| 30 | 65% | 14,235 | 1,130.74 | 1,130.74 | | 1,130.74 | 0.00 | 0.0% |
| 30 | 80% | 17,520 | 1,344.89 | 1,344.89 | | 1,344.89 | 0.00 | 0.0% |
| | | | | 0.00 | | | | |
| 75 | 20% | 10,950 | 1,036.15 | 1,036.15 | | 1,036.15 | 0.00 | 0.0% |
| 75 | 35% | 19,163 | 1,688.26 | 1,688.26 | | 1,688.26 | 0.00 | 0.0% |
| 75 | 50% | 27,375 | 2,247.78 | 2,247.78 | | 2,247.78 | 0.00 | 0.0% |
| 75 | 65% | 35,588 | 2,783.19 | 2,783.19 | | 2,783.19 | 0.00 | 0.0% |
| 75 | 80% | 43,800 | 3,318.53 | 3,318.53 | | 3,318.53 | 0.00 | 0.0% |
| | | | | 0.00 | | | | |
| 100 | 20% | 14,600 | 1,372.96 | 1,372.96 | | 1,372.96 | 0.00 | 0.0% |
| 100 | 35% | 25,550 | 2,242.39 | 2,242.39 | | 2,242.39 | 0.00 | 0.0% |
| 100 | 50% | 36,500 | 2,987.34 | 2,987.34 | | 2,987.34 | 0.00 | 0.0% |
| 100 | 65% | 47,450 | 3,701.17 | 3,701.17 | | 3,701.17 | 0.00 | 0.0% |
| 100 | 80% | 58,400 | 4,415.00 | 4,415.00 | | 4,415.00 | 0.00 | 0.0% |
| | | | | 0.00 | | | | |
| 150 | 20% | 21,900 | 2,046.58 | 2,046.58 | | 2,046.58 | 0.00 | 0.0% |
| 150 | 35% | 38,325 | 3,350.72 | 3,350.72 | | 3,350.72 | 0.00 | 0.0% |
| 150 | 50% | 54,750 | 4,466.44 | 4,466.44 | | 4,466.44 | 0.00 | 0.0% |
| 150 | 65% | 71,175 | 5,537.19 | 5,537.19 | | 5,537.19 | 0.00 | 0.0% |
| 150 | 80% | 87,600 | 6,607.93 | 6,607.93 | | 6,607.93 | 0.00 | 0.0% |
| | | | | 0.00 | | | | |
| 200 | 20% | 29,200 | 2,720.20 | 2,720.20 | | 2,720.20 | 0.00 | 0.0% |
| 200 | 35% | 51,100 | 4,459.06 | 4,459.06 | | 4,459.06 | 0.00 | 0.0% |
| 200 | 50% | 73,000 | 5,945.55 | 5,945.55 | | 5,945.55 | 0.00 | 0.0% |
| 200 | 65% | 94,900 | 7,373.21 | 7,373.21 | | 7,373.21 | 0.00 | 0.0% |
| 200 | 80% | 116,800 | 8,800.87 | 8,800.87 | | 8,800.87 | 0.00 | 0.0% |
| | | | | 0.00 | | | | |
| 300 | 20% | 43,800 | 4,067.44 | 4,067.44 | | 4,067.44 | 0.00 | 0.0% |
| 300 | 50% | 109,500 | 8,903.76 | 8,903.76 | | 8,903.76 | 0.00 | 0.0% |
| 300 | 65% | 142,350 | 11,045.25 | 11,045.25 | | 11,045.25 | 0.00 | 0.0% |
| 300 | 80% | 175,200 | 13,186.74 | 13,186.74 | | 13,186.74 | 0.00 | 0.0% |

Unbundled Transmission Charge (<=20 kW): $/kWh
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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 | Amount ($) | % |
| | | | | | | | (F) + (G) | (H) - (E) | (I) / (E) |
| 10 | 30 | 20% | 1,460 | 248.44 | 248.44 | | 248.44 | 0.00 | 0.0% |
| 10 | 30 | 35% | 2,555 | 319.38 | 319.38 | | 319.38 | 0.00 | 0.0% |
| 10 | 30 | 50% | 3,650 | 390.32 | 390.32 | | 390.32 | 0.00 | 0.0% |
| 10 | 30 | 65% | 4,745 | 461.25 | 461.25 | | 461.25 | 0.00 | 0.0% |
| 10 | 30 | 80% | 5,840 | 532.19 | 532.19 | | 532.19 | 0.00 | 0.0% |
| | | | | | 0.00 | | | | |
| 30 | 90 | 20% | 4,380 | 687.47 | 687.47 | | 687.47 | 0.00 | 0.0% |
| 30 | 90 | 35% | 7,665 | 900.29 | 900.29 | | 900.29 | 0.00 | 0.0% |
| 30 | 90 | 50% | 10,950 | 1,113.11 | 1,113.11 | | 1,113.11 | 0.00 | 0.0% |
| 30 | 90 | 65% | 14,235 | 1,325.92 | 1,325.92 | | 1,325.92 | 0.00 | 0.0% |
| 30 | 90 | 80% | 17,520 | 1,538.74 | 1,538.74 | | 1,538.74 | 0.00 | 0.0% |
| | | | | | 0.00 | | | | |
| 75 | 225 | 20% | 10,950 | 1,675.29 | 1,675.29 | | 1,675.29 | 0.00 | 0.0% |
| 75 | 225 | 35% | 19,163 | 2,207.37 | 2,207.37 | | 2,207.37 | 0.00 | 0.0% |
| 75 | 225 | 50% | 27,375 | 2,739.38 | 2,739.38 | | 2,739.38 | 0.00 | 0.0% |
| 75 | 225 | 65% | 35,588 | 3,271.46 | 3,271.46 | | 3,271.46 | 0.00 | 0.0% |
| 75 | 225 | 80% | 43,800 | 3,803.48 | 3,803.48 | | 3,803.48 | 0.00 | 0.0% |
| | | | | | 0.00 | | | | |
| 100 | 300 | 20% | 14,600 | 2,224.08 | 2,224.08 | | 2,224.08 | 0.00 | 0.0% |
| 100 | 300 | 35% | 25,550 | 2,933.48 | 2,933.48 | | 2,933.48 | 0.00 | 0.0% |
| 100 | 300 | 50% | 36,500 | 3,642.87 | 3,642.87 | | 3,642.87 | 0.00 | 0.0% |
| 100 | 300 | 65% | 47,450 | 4,352.27 | 4,352.27 | | 4,352.27 | 0.00 | 0.0% |
| 100 | 300 | 80% | 58,400 | 5,061.66 | 5,061.66 | | 5,061.66 | 0.00 | 0.0% |
| | | | | | 0.00 | | | | |
| 150 | 450 | 20% | 21,900 | 3,321.66 | 3,321.66 | | 3,321.66 | 0.00 | 0.0% |
| 150 | 450 | 35% | 38,325 | 4,385.76 | 4,385.76 | | 4,385.76 | 0.00 | 0.0% |
| 150 | 450 | 50% | 54,750 | 5,449.85 | 5,449.85 | | 5,449.85 | 0.00 | 0.0% |
| 150 | 450 | 65% | 71,175 | 6,513.94 | 6,513.94 | | 6,513.94 | 0.00 | 0.0% |
| 150 | 450 | 80% | 87,600 | 7,578.04 | 7,578.04 | | 7,578.04 | 0.00 | 0.0% |
| | | | | | 0.00 | | | | |
| 200 | 600 | 20% | 29,200 | 4,419.24 | 4,419.24 | | 4,419.24 | 0.00 | 0.0% |
| 200 | 600 | 35% | 51,100 | 5,838.03 | 5,838.03 | | 5,838.03 | 0.00 | 0.0% |
| 200 | 600 | 50% | 73,000 | 7,256.83 | 7,256.83 | | 7,256.83 | 0.00 | 0.0% |
| 200 | 600 | 65% | 94,900 | 8,675.62 | 8,675.62 | | 8,675.62 | 0.00 | 0.0% |
| 200 | 600 | 80% | 116,800 | 10,094.41 | 10,094.41 | | 10,094.41 | 0.00 | 0.0% |
| | | | | | 0.00 | | | | |
| 300 | 900 | 20% | 43,800 | 6,614.40 | 6,614.40 | | 6,614.40 | 0.00 | 0.0% |
| 300 | 900 | 50% | 109,500 | 10,870.78 | 10,870.78 | | 10,870.78 | 0.00 | 0.0% |
| 300 | 900 | 65% | 142,350 | 12,998.96 | 12,998.96 | | 12,998.96 | 0.00 | 0.0% |
| 300 | 900 | 80% | 175,200 | 15,127.15 | 15,127.15 | | 15,127.15 | 0.00 | 0.0% |

E-221-8T Average Energy On-Peak: 30%
Unbundled Transmission Charge (<=20 kW): $/kWh
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) Present Rates are rates effective 1/1/2010.

## Arizona Public Service Company
## Test Year Ending December 2010
## Typical Classified Service Bill Analysis
## GS-SCHOOLS 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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 101 | 15% | 11,060 | 1,756.43 | 1,756.43 | | 1,756.43 | - | 0.0% |
| 101 | 30% | 22,119 | 2,508.28 | 2,508.28 | | 2,508.28 | - | 0.0% |
| 101 | 45% | 33,179 | 3,260.19 | 3,260.19 | | 3,260.19 | - | 0.0% |
| 101 | 60% | 44,238 | 4,012.03 | 4,012.03 | | 4,012.03 | - | 0.0% |
| 101 | 75% | 55,298 | 4,763.94 | 4,763.94 | | 4,763.94 | - | 0.0% |
| | | | | - | | | | |
| 150 | 15% | 16,425 | 2,371.32 | 2,371.32 | | 2,371.32 | - | 0.0% |
| 150 | 30% | 32,850 | 3,487.96 | 3,487.96 | | 3,487.96 | - | 0.0% |
| 150 | 45% | 49,275 | 4,604.61 | 4,604.61 | | 4,604.61 | - | 0.0% |
| 150 | 60% | 65,700 | 5,721.26 | 5,721.26 | | 5,721.26 | - | 0.0% |
| 150 | 75% | 82,125 | 6,837.91 | 6,837.91 | | 6,837.91 | - | 0.0% |
| | | | | - | | | | |
| 200 | 15% | 21,900 | 2,998.78 | 2,998.78 | | 2,998.78 | - | 0.0% |
| 200 | 30% | 43,800 | 4,487.65 | 4,487.65 | | 4,487.65 | - | 0.0% |
| 200 | 45% | 65,700 | 5,976.51 | 5,976.51 | | 5,976.51 | - | 0.0% |
| 200 | 60% | 87,600 | 7,465.37 | 7,465.37 | | 7,465.37 | - | 0.0% |
| 200 | 75% | 109,500 | 8,954.23 | 8,954.23 | | 8,954.23 | - | 0.0% |
| | | | | - | | | | |
| 300 | 15% | 32,850 | 4,253.71 | 4,253.71 | | 4,253.71 | - | 0.0% |
| 300 | 30% | 65,700 | 6,487.01 | 6,487.01 | | 6,487.01 | - | 0.0% |
| 300 | 45% | 98,550 | 8,720.30 | 8,720.30 | | 8,720.30 | - | 0.0% |
| 300 | 60% | 131,400 | 10,953.60 | 10,953.60 | | 10,953.60 | - | 0.0% |
| 300 | 75% | 164,250 | 13,186.89 | 13,186.89 | | 13,186.89 | - | 0.0% |
| | | | | - | | | | |
| 350 | 15% | 38,325 | 4,881.18 | 4,881.18 | | 4,881.18 | - | 0.0% |
| 350 | 30% | 76,650 | 7,486.69 | 7,486.69 | | 7,486.69 | - | 0.0% |
| 350 | 45% | 114,975 | 10,092.20 | 10,092.20 | | 10,092.20 | - | 0.0% |
| 350 | 60% | 153,300 | 12,697.71 | 12,697.71 | | 12,697.71 | - | 0.0% |
| 350 | 75% | 191,625 | 15,303.22 | 15,303.22 | | 15,303.22 | - | 0.0% |
| | | | | - | | | | |
| 400 | 15% | 43,800 | 5,508.65 | 5,508.65 | | 5,508.65 | - | 0.0% |
| 400 | 30% | 87,600 | 8,486.37 | 8,486.37 | | 8,486.37 | - | 0.0% |
| 400 | 45% | 131,400 | 11,464.10 | 11,464.10 | | 11,464.10 | - | 0.0% |
| 400 | 60% | 175,200 | 14,441.82 | 14,441.82 | | 14,441.82 | - | 0.0% |
| 400 | 75% | 219,000 | 17,419.55 | 17,419.55 | | 17,419.55 | - | 0.0% |

GS-SCHOOLS M Average Energy On-Peak %: 24%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 17%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools M effective 8/31/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Classified Service Bill Analysis**
**GS-SCHOOLS M Summer Shoulder (May, September & 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 | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 101 | 15% | 11,060 | 1,953.24 | 1,953.24 | | 1,953.24 | - | 0.0% |
| 101 | 30% | 22,119 | 2,901.87 | 2,901.87 | | 2,901.87 | - | 0.0% |
| 101 | 45% | 33,179 | 3,850.58 | 3,850.58 | | 3,850.58 | - | 0.0% |
| 101 | 60% | 44,238 | 4,799.21 | 4,799.21 | | 4,799.21 | - | 0.0% |
| 101 | 75% | 55,298 | 5,747.92 | 5,747.92 | | 5,747.92 | - | 0.0% |
| | | | | - | | | | |
| 150 | 15% | 16,425 | 2,663.59 | 2,663.59 | | 2,663.59 | - | 0.0% |
| 150 | 30% | 32,850 | 4,072.50 | 4,072.50 | | 4,072.50 | - | 0.0% |
| 150 | 45% | 49,275 | 5,481.42 | 5,481.42 | | 5,481.42 | - | 0.0% |
| 150 | 60% | 65,700 | 6,890.34 | 6,890.34 | | 6,890.34 | - | 0.0% |
| 150 | 75% | 82,125 | 8,299.25 | 8,299.25 | | 8,299.25 | - | 0.0% |
| | | | | - | | | | |
| 200 | 15% | 21,900 | 3,388.48 | 3,388.48 | | 3,388.48 | - | 0.0% |
| 200 | 30% | 43,800 | 5,267.03 | 5,267.03 | | 5,267.03 | - | 0.0% |
| 200 | 45% | 65,700 | 7,145.59 | 7,145.59 | | 7,145.59 | - | 0.0% |
| 200 | 60% | 87,600 | 9,024.14 | 9,024.14 | | 9,024.14 | - | 0.0% |
| 200 | 75% | 109,500 | 10,902.70 | 10,902.70 | | 10,902.70 | - | 0.0% |
| | | | | - | | | | |
| 300 | 15% | 32,850 | 4,838.25 | 4,838.25 | | 4,838.25 | - | 0.0% |
| 300 | 30% | 65,700 | 7,656.09 | 7,656.09 | | 7,656.09 | - | 0.0% |
| 300 | 45% | 98,550 | 10,473.92 | 10,473.92 | | 10,473.92 | - | 0.0% |
| 300 | 60% | 131,400 | 13,291.75 | 13,291.75 | | 13,291.75 | - | 0.0% |
| 300 | 75% | 164,250 | 16,109.59 | 16,109.59 | | 16,109.59 | - | 0.0% |
| | | | | - | | | | |
| 350 | 15% | 38,325 | 5,563.14 | 5,563.14 | | 5,563.14 | - | 0.0% |
| 350 | 30% | 76,650 | 8,850.62 | 8,850.62 | | 8,850.62 | - | 0.0% |
| 350 | 45% | 114,975 | 12,138.09 | 12,138.09 | | 12,138.09 | - | 0.0% |
| 350 | 60% | 153,300 | 15,425.56 | 15,425.56 | | 15,425.56 | - | 0.0% |
| 350 | 75% | 191,625 | 18,713.03 | 18,713.03 | | 18,713.03 | - | 0.0% |
| | | | | - | | | | |
| 400 | 15% | 43,800 | 6,288.03 | 6,288.03 | | 6,288.03 | - | 0.0% |
| 400 | 30% | 87,600 | 10,045.14 | 10,045.14 | | 10,045.14 | - | 0.0% |
| 400 | 45% | 131,400 | 13,802.25 | 13,802.25 | | 13,802.25 | - | 0.0% |
| 400 | 60% | 175,200 | 17,559.37 | 17,559.37 | | 17,559.37 | - | 0.0% |
| 400 | 75% | 219,000 | 21,316.48 | 21,316.48 | | 21,316.48 | - | 0.0% |

GS-SCHOOLS M Average Energy On-Peak %: 19%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 22%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools M effective 8/31/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Classified Service Bill Analysis**
**GS-SCHOOLS M Summer Peak (June-August)**

**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) |
| 101 | 15% | 11,060 | 2,077.13 | 2,077.13 | | 2,077.13 | - | 0.0% |
| 101 | 30% | 22,119 | 3,149.63 | 3,149.63 | | 3,149.63 | - | 0.0% |
| 101 | 45% | 33,179 | 4,222.23 | 4,222.23 | | 4,222.23 | - | 0.0% |
| 101 | 60% | 44,238 | 5,294.74 | 5,294.74 | | 5,294.74 | - | 0.0% |
| 101 | 75% | 55,298 | 6,367.34 | 6,367.34 | | 6,367.34 | - | 0.0% |
| | | | | - | | | | |
| 150 | 15% | 16,425 | 2,847.57 | 2,847.57 | | 2,847.57 | - | 0.0% |
| 150 | 30% | 32,850 | 4,440.47 | 4,440.47 | | 4,440.47 | - | 0.0% |
| 150 | 45% | 49,275 | 6,033.37 | 6,033.37 | | 6,033.37 | - | 0.0% |
| 150 | 60% | 65,700 | 7,626.27 | 7,626.27 | | 7,626.27 | - | 0.0% |
| 150 | 75% | 82,125 | 9,219.17 | 9,219.17 | | 9,219.17 | - | 0.0% |
| | | | | - | | | | |
| 200 | 15% | 21,900 | 3,633.79 | 3,633.79 | | 3,633.79 | - | 0.0% |
| 200 | 30% | 43,800 | 5,757.65 | 5,757.65 | | 5,757.65 | - | 0.0% |
| 200 | 45% | 65,700 | 7,881.52 | 7,881.52 | | 7,881.52 | - | 0.0% |
| 200 | 60% | 87,600 | 10,005.39 | 10,005.39 | | 10,005.39 | - | 0.0% |
| 200 | 75% | 109,500 | 12,129.25 | 12,129.25 | | 12,129.25 | - | 0.0% |
| | | | | - | | | | |
| 300 | 15% | 32,850 | 5,206.22 | 5,206.22 | | 5,206.22 | - | 0.0% |
| 300 | 30% | 65,700 | 8,392.02 | 8,392.02 | | 8,392.02 | - | 0.0% |
| 300 | 45% | 98,550 | 11,577.82 | 11,577.82 | | 11,577.82 | - | 0.0% |
| 300 | 60% | 131,400 | 14,763.62 | 14,763.62 | | 14,763.62 | - | 0.0% |
| 300 | 75% | 164,250 | 17,949.42 | 17,949.42 | | 17,949.42 | - | 0.0% |
| | | | | - | | | | |
| 350 | 15% | 38,325 | 5,992.44 | 5,992.44 | | 5,992.44 | - | 0.0% |
| 350 | 30% | 76,650 | 9,709.20 | 9,709.20 | | 9,709.20 | - | 0.0% |
| 350 | 45% | 114,975 | 13,425.97 | 13,425.97 | | 13,425.97 | - | 0.0% |
| 350 | 60% | 153,300 | 17,142.73 | 17,142.73 | | 17,142.73 | - | 0.0% |
| 350 | 75% | 191,625 | 20,859.50 | 20,859.50 | | 20,859.50 | - | 0.0% |
| | | | | - | | | | |
| 400 | 15% | 43,800 | 6,778.65 | 6,778.65 | | 6,778.65 | - | 0.0% |
| 400 | 30% | 87,600 | 11,026.39 | 11,026.39 | | 11,026.39 | - | 0.0% |
| 400 | 45% | 131,400 | 15,274.12 | 15,274.12 | | 15,274.12 | - | 0.0% |
| 400 | 60% | 175,200 | 19,521.85 | 19,521.85 | | 19,521.85 | - | 0.0% |
| 400 | 75% | 219,000 | 23,769.58 | 23,769.58 | | 23,769.58 | - | 0.0% |

GS-SCHOOLS M Average Energy On-Peak %: 18%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 20%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools M effective 8/31/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Classified Service Bill Analysis**
**GS-SCHOOLS 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) |
|---|---|---|---|---|---|---|---|---|
| | | | 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) |
| 401 | 15% | 43,910 | 5,240.48 | 5,240.48 | | 5,240.48 | - | 0.0% |
| 401 | 30% | 87,819 | 7,990.80 | 7,990.80 | | 7,990.80 | - | 0.0% |
| 401 | 45% | 131,729 | 10,741.17 | 10,741.17 | | 10,741.17 | - | 0.0% |
| 401 | 60% | 175,638 | 13,491.49 | 13,491.49 | | 13,491.49 | - | 0.0% |
| 401 | 75% | 219,548 | 16,241.87 | 16,241.87 | | 16,241.87 | - | 0.0% |
| | | | | - | | | | |
| 600 | 15% | 65,700 | 7,598.94 | 7,598.94 | | 7,598.94 | - | 0.0% |
| 600 | 30% | 131,400 | 11,714.17 | 11,714.17 | | 11,714.17 | - | 0.0% |
| 600 | 45% | 197,100 | 15,829.40 | 15,829.40 | | 15,829.40 | - | 0.0% |
| 600 | 60% | 262,800 | 19,944.63 | 19,944.63 | | 19,944.63 | - | 0.0% |
| 600 | 75% | 328,500 | 24,059.87 | 24,059.87 | | 24,059.87 | - | 0.0% |
| | | | | - | | | | |
| 800 | 15% | 87,600 | 9,969.28 | 9,969.28 | | 9,969.28 | - | 0.0% |
| 800 | 30% | 175,200 | 15,456.26 | 15,456.26 | | 15,456.26 | - | 0.0% |
| 800 | 45% | 262,800 | 20,943.23 | 20,943.23 | | 20,943.23 | - | 0.0% |
| 800 | 60% | 350,400 | 26,430.21 | 26,430.21 | | 26,430.21 | - | 0.0% |
| 800 | 75% | 438,000 | 31,917.18 | 31,917.18 | | 31,917.18 | - | 0.0% |
| | | | | - | | | | |
| 1,000 | 15% | 109,500 | 12,339.63 | 12,339.63 | | 12,339.63 | - | 0.0% |
| 1,000 | 30% | 219,000 | 19,198.35 | 19,198.35 | | 19,198.35 | - | 0.0% |
| 1,000 | 45% | 328,500 | 26,057.07 | 26,057.07 | | 26,057.07 | - | 0.0% |
| 1,000 | 60% | 438,000 | 32,915.78 | 32,915.78 | | 32,915.78 | - | 0.0% |
| 1,000 | 75% | 547,500 | 39,774.50 | 39,774.50 | | 39,774.50 | - | 0.0% |
| | | | | - | | | | |
| 1,500 | 15% | 164,250 | 18,265.49 | 18,265.49 | | 18,265.49 | - | 0.0% |
| 1,500 | 30% | 328,500 | 28,553.57 | 28,553.57 | | 28,553.57 | - | 0.0% |
| 1,500 | 45% | 492,750 | 38,841.64 | 38,841.64 | | 38,841.64 | - | 0.0% |
| 1,500 | 60% | 657,000 | 49,129.72 | 49,129.72 | | 49,129.72 | - | 0.0% |
| 1,500 | 75% | 821,250 | 59,417.80 | 59,417.80 | | 59,417.80 | - | 0.0% |
| | | | | - | | | | |
| 3,000 | 15% | 328,500 | 36,043.07 | 36,043.07 | | 36,043.07 | - | 0.0% |
| 3,000 | 30% | 657,000 | 56,619.22 | 56,619.22 | | 56,619.22 | - | 0.0% |
| 3,000 | 45% | 985,500 | 77,195.38 | 77,195.38 | | 77,195.38 | - | 0.0% |
| 3,000 | 60% | 1,314,000 | 97,771.53 | 97,771.53 | | 97,771.53 | - | 0.0% |
| 3,000 | 75% | 1,642,500 | 118,347.69 | 118,347.69 | | 118,347.69 | - | 0.0% |

| | | |
|---|---|---|
| GS-SCHOOLS L Average Energy On-Peak %: | 23% | |
| GS-SCHOOLS L Average Energy Shoulder-Peak %: | 18% | |
| Unbundled Transmission Charge (>20 kW and <3,000): | | $/kW |

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools L effective 8/31/2010.
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)

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Classified Service Bill Analysis**
**GS-SCHOOLS L Summer Shoulder (May, September & 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 | Amount ($) | % |
| | | | | | | (E) + (F) | (G) - (D) | (H) / (D) |
| 401 | 15% | 43,910 | 5,865.81 | 5,865.81 | | 5,865.81 | - | 0.0% |
| 401 | 30% | 87,819 | 9,241.43 | 9,241.43 | | 9,241.43 | - | 0.0% |
| 401 | 45% | 131,729 | 12,617.14 | 12,617.14 | | 12,617.14 | - | 0.0% |
| 401 | 60% | 175,638 | 15,992.77 | 15,992.77 | | 15,992.77 | - | 0.0% |
| 401 | 75% | 219,548 | 19,368.47 | 19,368.47 | | 19,368.47 | - | 0.0% |
| | | | | - | | | | |
| 600 | 15% | 65,700 | 8,534.58 | 8,534.58 | | 8,534.58 | - | 0.0% |
| 600 | 30% | 131,400 | 13,585.45 | 13,585.45 | | 13,585.45 | - | 0.0% |
| 600 | 45% | 197,100 | 18,636.32 | 18,636.32 | | 18,636.32 | - | 0.0% |
| 600 | 60% | 262,800 | 23,687.20 | 23,687.20 | | 23,687.20 | - | 0.0% |
| 600 | 75% | 328,500 | 28,738.07 | 28,738.07 | | 28,738.07 | - | 0.0% |
| | | | | - | | | | |
| 800 | 15% | 87,600 | 11,216.81 | 11,216.81 | | 11,216.81 | - | 0.0% |
| 800 | 30% | 175,200 | 17,951.30 | 17,951.30 | | 17,951.30 | - | 0.0% |
| 800 | 45% | 262,800 | 24,685.80 | 24,685.80 | | 24,685.80 | - | 0.0% |
| 800 | 60% | 350,400 | 31,420.29 | 31,420.29 | | 31,420.29 | - | 0.0% |
| 800 | 75% | 438,000 | 38,154.79 | 38,154.79 | | 38,154.79 | - | 0.0% |
| | | | | - | | | | |
| 1,000 | 15% | 109,500 | 13,899.03 | 13,899.03 | | 13,899.03 | - | 0.0% |
| 1,000 | 30% | 219,000 | 22,317.15 | 22,317.15 | | 22,317.15 | - | 0.0% |
| 1,000 | 45% | 328,500 | 30,735.27 | 30,735.27 | | 30,735.27 | - | 0.0% |
| 1,000 | 60% | 438,000 | 39,153.39 | 39,153.39 | | 39,153.39 | - | 0.0% |
| 1,000 | 75% | 547,500 | 47,571.51 | 47,571.51 | | 47,571.51 | - | 0.0% |
| | | | | - | | | | |
| 1,500 | 15% | 164,250 | 20,604.59 | 20,604.59 | | 20,604.59 | - | 0.0% |
| 1,500 | 30% | 328,500 | 33,231.77 | 33,231.77 | | 33,231.77 | - | 0.0% |
| 1,500 | 45% | 492,750 | 45,858.95 | 45,858.95 | | 45,858.95 | - | 0.0% |
| 1,500 | 60% | 657,000 | 58,486.12 | 58,486.12 | | 58,486.12 | - | 0.0% |
| 1,500 | 75% | 821,250 | 71,113.30 | 71,113.30 | | 71,113.30 | - | 0.0% |
| | | | | - | | | | |
| 3,000 | 15% | 328,500 | 40,721.27 | 40,721.27 | | 40,721.27 | - | 0.0% |
| 3,000 | 30% | 657,000 | 65,975.62 | 65,975.62 | | 65,975.62 | - | 0.0% |
| 3,000 | 45% | 985,500 | 91,229.98 | 91,229.98 | | 91,229.98 | - | 0.0% |
| 3,000 | 60% | 1,314,000 | 116,484.34 | 116,484.34 | | 116,484.34 | - | 0.0% |
| 3,000 | 75% | 1,642,500 | 141,738.70 | 141,738.70 | | 141,738.70 | - | 0.0% |

GS-SCHOOLS L Average Energy On-Peak %: 18%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 18%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools L effective 8/31/2010.
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)

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Classified Service Bill Analysis**
**GS-SCHOOLS L Summer Peak (June-August)**

**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) |
| 401 | 15% | 43,910 | 6,354.19 | 6,354.19 | | 6,354.19 | - | 0.0% |
| 401 | 30% | 87,819 | 10,218.19 | 10,218.19 | | 10,218.19 | - | 0.0% |
| 401 | 45% | 131,729 | 14,082.28 | 14,082.28 | | 14,082.28 | - | 0.0% |
| 401 | 60% | 175,638 | 17,946.28 | 17,946.28 | | 17,946.28 | - | 0.0% |
| 401 | 75% | 219,548 | 21,810.37 | 21,810.37 | | 21,810.37 | - | 0.0% |
| | | | | - | | | | |
| 600 | 15% | 65,700 | 9,265.32 | 9,265.32 | | 9,265.32 | - | 0.0% |
| 600 | 30% | 131,400 | 15,046.94 | 15,046.94 | | 15,046.94 | - | 0.0% |
| 600 | 45% | 197,100 | 20,828.55 | 20,828.55 | | 20,828.55 | - | 0.0% |
| 600 | 60% | 262,800 | 26,610.16 | 26,610.16 | | 26,610.16 | - | 0.0% |
| 600 | 75% | 328,500 | 32,391.78 | 32,391.78 | | 32,391.78 | - | 0.0% |
| | | | | - | | | | |
| 800 | 15% | 87,600 | 12,191.13 | 12,191.13 | | 12,191.13 | - | 0.0% |
| 800 | 30% | 175,200 | 19,899.95 | 19,899.95 | | 19,899.95 | - | 0.0% |
| 800 | 45% | 262,800 | 27,608.76 | 27,608.76 | | 27,608.76 | - | 0.0% |
| 800 | 60% | 350,400 | 35,317.58 | 35,317.58 | | 35,317.58 | - | 0.0% |
| 800 | 75% | 438,000 | 43,026.40 | 43,026.40 | | 43,026.40 | - | 0.0% |
| | | | | - | | | | |
| 1,000 | 15% | 109,500 | 15,116.93 | 15,116.93 | | 15,116.93 | - | 0.0% |
| 1,000 | 30% | 219,000 | 24,752.95 | 24,752.95 | | 24,752.95 | - | 0.0% |
| 1,000 | 45% | 328,500 | 34,388.98 | 34,388.98 | | 34,388.98 | - | 0.0% |
| 1,000 | 60% | 438,000 | 44,025.00 | 44,025.00 | | 44,025.00 | - | 0.0% |
| 1,000 | 75% | 547,500 | 53,661.02 | 53,661.02 | | 53,661.02 | - | 0.0% |
| | | | | - | | | | |
| 1,500 | 15% | 164,250 | 22,431.44 | 22,431.44 | | 22,431.44 | - | 0.0% |
| 1,500 | 30% | 328,500 | 36,885.48 | 36,885.48 | | 36,885.48 | - | 0.0% |
| 1,500 | 45% | 492,750 | 51,339.51 | 51,339.51 | | 51,339.51 | - | 0.0% |
| 1,500 | 60% | 657,000 | 65,793.54 | 65,793.54 | | 65,793.54 | - | 0.0% |
| 1,500 | 75% | 821,250 | 80,247.57 | 80,247.57 | | 80,247.57 | - | 0.0% |
| | | | | - | | | | |
| 3,000 | 15% | 328,500 | 44,374.98 | 44,374.98 | | 44,374.98 | - | 0.0% |
| 3,000 | 30% | 657,000 | 73,283.04 | 73,283.04 | | 73,283.04 | - | 0.0% |
| 3,000 | 45% | 985,500 | 102,191.11 | 102,191.11 | | 102,191.11 | - | 0.0% |
| 3,000 | 60% | 1,314,000 | 131,099.17 | 131,099.17 | | 131,099.17 | - | 0.0% |
| 3,000 | 75% | 1,642,500 | 160,007.24 | 160,007.24 | | 160,007.24 | - | 0.0% |

GS-SCHOOLS L Average Energy On-Peak %: 18%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 16%
Unbundled Transmission Charge (>20 kW and <3,000): $/kW

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:
1) Bills do not include REAC-1, PSA-1, TCA-1, DSMAC-1, EIA-1, ERA-1, Regulatory Assessment, or Tax charges.
2) GS-Schools L effective 8/31/2010.
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

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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) |
|---|---|---|---|---|---|---|---|
| | | | | 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 General Service Rate Schedules:

**Arizona Public Service Company**
**Test Year Ending December 2010**
**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-36 XL
E-56

**Arizona Public Service Company**
**Test Year Ending December 2010**
**Typical Residential 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:

EXHIBIT
RUCO
4

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF

FRANK W. RADIGAN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

IN SUPPORT OF SETTLEMENT AGREEMENT

JANUARY 18, 2012

**INTRODUCTION**

**Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS FOR THE RECORD.**

A. My name is Frank Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding utility industries 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 SUBMITTED TESTIMONY IN THIS PROCEEDING?**

A. Yes.

**Q. WHAT IS THE PURPOSE OF YOUR ADDITONAL DIRECT TESTIMONY?**

A. I will discuss the technical aspects of the proposed Settlement Agreement ("Settlement") filed on January 6, 2012 in Docket No. E-01345-A-11-0224 -- Arizona Public Service Company's request for rate adjustment.

**Q. DOES RUCO SUPPORT THE SETTLEMENT?**

A. Yes, for the reasons that follow as well as the reasons set forth in the testimony of Residential Utility Consumer Office's ("RUCO") Director Jodi Jerich being filed contemporaneously with my testimony.

**Q. WHAT ARE THE MAIN TECHNICAL ELEMENTS THAT RUCO ENDORSES IN THE SETTLEMENT?**

A. While I am sure that many people would point to the fact that there is no rate increase in this case as a primary feature of the Settlement, I would note that the RUCO in its direct case as well as several other parties showed that there was no need for a rate increase at this time. In its direct case, RUCO showed that the instant rate case was more the matter of the Arizona Public Service Company ("APS" or the "Company") advocating for a simple increase in profits and several adjustment mechanisms that passed risk on to ratepayers and helped protect its net income. For example, in its direct case, APS sought a very generous 11% return on equity. The Company also sought to include chemical costs in the Power Supply Adjustment ("PSA"). The Company also advocated for an Environmental and Reliability Account mechanism that would allow recovery of the carrying costs of environmental improvement projects and for projects relating to generating plant capacity acquisitions or additions. Finally, the Company sought the elimination of the 90/10 ratepayer/stockholder sharing mechanism in the PSA.

I give this background only to show that many aspects of the Settlement had a high probability of outcome in a fully adjudicated proceeding and note that it is not the rate increase that should be focused upon, but rather the other elements of the Settlement that provide value to ratepayers. To illustrate this point, in its direct case RUCO presented a much more balanced case where it would only allow a 10% return on equity, no increase in base rates and rejection of most of the new adjuster mechanisms or changes to the old.

Most of the elements of RUCO's direct case have been incorporated into the Settlement such as the no base rate increase and the 10% return on equity.

**Q. COULD YOU PLEASE SUMMARIZE THE KEY ELEMENTS OF THE SETTLEMENT?**

A. From RUCO's perspective, there are five key terms of the Settlement:

1. the overall zero dollar base rate increase <u>with</u> a four year rate case stay out, in which APS agrees not to raise base rates as a result of any new general rate case filing until at least mid-2016;
2. a narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by this Commission;
3. an opt-out rate design for residential customers who choose not to participate in the LFCR which will also support EE and DG at the requisite Commission standards;
4. a process for simplifying customers' bill format; and
5. elimination of the Company's proposed changes to the Transmission Cost Adjustor, the withdrawal of the request to recover chemical costs through the Power Supply Adjustor, the withdrawal of the request for the introduction of an Environmental and Reliability Account

Section 2.1 of the Settlement states that APS agrees not to file its next general rate case prior to May 31, 2015, and no new base rates resulting from APS's next general rate case will be effective before July 1, 2016. This is a key element of the settlement as it represents a four-year moratorium on rate cases where ratepayers will see no increase in base rates, and it puts the onus on management to control operating expenses, minimize capital expenditures, and improve the productivity of its work force.

In addition, Section 4.1 of the Settlement states that when new rates become effective, customers will have on average a 0.0% bill impact or less. This zero percent or slightly negative bill impact will be achieved by allowing the negative credit that exists in the Company's PSA to continue until February 1, 2013, at which time it will reset (Id). The actual rate impacts due to the Settlement's provisions for low-income customers and the reset of the PSA and discussion of bill impacts will be discussed in more detail later in my testimony.

**Q. COULD YOU PLEASE DISCUSS THE LOST FIXED COST RECOVERY MECHANISM?**

A. The Settlement implements a Lost Fixed Cost Recovery ("LFCR") mechanism in Section 9. This portion of the Settlement addresses the interest in directing EE and DG policy. The LFCR shall recover a portion of distribution and transmission costs when sales levels are reduced by EE and DG. It shall not recover lost fixed costs attributable to other potential factors, such as weather or general economic conditions. To minimize its impact, the amount of the LFCR mechanism excludes the portion of distribution and transmission costs recovered through the Basic Service Charge ("BSC") and fifty (50) percent of such costs recovered through non-generation/non-transmission demand charges. The LFCR shall be adjusted annually to account for the unrecovered costs, as demonstrated, and is subject to a 1% year over year cap. Any amount in excess of the cap will be deferred.

Section 9.8 of the Settlement states that residential customers shall have the ability to opt out of the LFCR by electing to pay a slightly higher BSC. The purpose of this opt-out rate is to replicate, on average, the effects of the LFCR, and allow customers who are not comfortable with the LFCR mechanism the option to opt-out. Section 9.9 of the Settlement states that APS shall seek stakeholder input regarding and subsequently the development of a customer outreach program to inform and educate customers about both the LFCR and voluntary opt-out rates and shall implement this outreach program.

The LFCR is an alternative to the full decoupling mechanism that the Company requested in its original case. In its direct case, RUCO stated that it was inappropriate to implement a decoupling mechanism during this period of economic uncertainty and financial stress for ratepayers. RUCO supports the LFCR as presented in the Settlement because customers who do not want it have the option of another rate design. The ability to opt-out of the LFCR is important as it provides the Company the financial protection for lost sales from EE and DG but it also gives ratepayers the right to vote on these public policy programs advocated by some groups. Similarly, the cap on the LFCR minimizes to a reasonable degree the financial impact of the LFCR and which I note has been the downfall of some decoupling mechanisms in the past.

**Q. COULD YOU PLEAE DISCUSS THE RESOLUTION OF BILL PRESENTAITON?**

A. Section 16.1 of the Settlement states that within 90 days following approval of the Settlement, APS will initiate stakeholder meetings to address issues related to the APS bill presentation with a goal of making the bill easier for customers to understand. The Settlement also states that APS will thereafter file an application with the Commission for any authorization needed to modify its bill presentation. Such application shall explain how the APS bill presentation proposal reflects the input of stakeholders during the stakeholder meeting process.

The current APS bill is unbundled with rates for specific services such as billing, metering, system benefits, distribution delivery, transmission, and generation capacity and energy. During the course of the proceeding, it was found that this makes for a fairly long and complicated bill that can sometimes cause customer complaints. To address this issue, in direct testimony the Company proposed to simplify the customers' bill by providing the bundled charges and related information. RUCO supported any efforts that will result in bill simplification, and it is my experience that customers are generally wary of adjustor mechanisms and surcharges. The parties were unable to resolve all issues relating to bill simplification during the proceeding and the initiation of stakeholder meetings should provide the venue to resolve this important issue.

**Q. WHAT ARE SOME OTHER IMPORTANT ELEMENTS OF THE SETTLEMENT?**

A. Section 7.2 states that APS will withdraw its request to recover through the PSA the cost of chemicals required for environmental compliance at APS's power plants, and APS shall not raise this request before its next general rate case. As I discussed in my direct testimony, the chemical cost is a cost of doing business, just like thousands of other expense items that the Company has to deal with. There is nothing unique about chemical costs and the elimination of this cost is appropriate.

Section 11.1 of the Settlement provides that APS shall withdraw its request for approval of the proposed Environmental and Reliability Account ("ERA") mechanism, and APS shall not raise this request before its next general rate case. As originally proposed, the ERA mechanism would allow recovery of the carrying costs of projects related to environmental improvement or acquisition/additions of generating capacity. To qualify for recovery under the ERA mechanism a project would have to be generation related and it costs would exceed $500,000. In its direct case, RUCO opposed the mechanism because the threshold of $500,000 as proposed by the Company is so low that it would result in almost <u>any</u> project at a generation plant being qualified for cost recovery. In effect, the proposed ERA mechanism was akin to a formula rate plan that would only benefit shareholders. The Settlement properly excluded the mechanism.

Section 13.1 of the Settlement provides that the level of transmission costs presently in APS's base rates will remain in base rates until further order of the Commission. The Company had originally sought to have all transmission costs recovered through the Transmission Cost Adjustor ("TCA"). In its direct case, RUCO recommended against the full recovery in the TCA because RUCO believes that adjustor mechanisms are unwarranted unless, among other things, the costs recovered through the adjustor are highly volatile and beyond the Company's ability to control. RUCO does believe that the Company had shown transmission costs to be highly volatile or beyond its control. The Settlement properly excludes the mechanism.

Section 7.3 states that the 90/10 sharing provision in APS's PSA will be eliminated. In its stead, to incent prudent fuel procurement and use, APS shall be subject to periodic fuel audits. The first fuel audit shall be for 2014. I have been involved in incentive power supply mechanisms for my whole thirty years career and in my experience have learned that Utility's operate and maintain their low costs power plants (coal, hydro and nuclear) at very high availability and capacity factors when they have a monetary stake in their operation. As I stated in my direct testimony the PSA is a much better control for the efforts on the Company's part on a day-to-day basis rather than some after the fact prudence case. That said, this is just one element of the Settlement that must be weighed against all others. On balance, I would not let my opposition to this one provision, while important, hold up support of the Settlement.

**Q. COULD YOU PLEASE DSCUSS THE BILL IMPACTS RESULTING FROM THE SETTLEMENT?**

A. Yes, as I mentioned previously, Section 4.1 of the Settlement states that when new rates become effective, customers will have on average a 0.0% bill impact or less. For residential customers this provision will result in a slight rate increase in base rates for the non low-income residential customers, and a slight decrease in base rates for low-income residential customers. The reason for this is that Section 14.2 of the Settlement requires that low-income customers will have the PSA and Demand Side Management Adjustor Mechanism applied to their bills. This provision has the effect of increasing non low-income base rates and reducing low-income base rate, and can be best seen on the Company's proof of revenue that supports the rates contained in the Settlement. I have included the proof of revenue as an attachment to my testimony. I include this so that the Commission has a full understanding of the rate impacts that result from the Settlement.

Along these same lines, I would also like to point out that there are two other elements of the Settlement that could cause rates to increase above the zero percent level. First, the PSA is due to be reset in February 2013 (See Section 4.1). The Company has provided rate impacts based on its forecast of changes to the PSA in a letter dated January 9, 2012 and is part of the record in this proceeding. The Company estimates that the PSA reset will have the impact of increasing the average bill for a residential customer in February 2013 by 3.5%.

The second factor that could increase bills beyond December 31, 2012 (See Section 1.5) reflects the fact that in Docket No. E-01345A-10-0474, APS has sought Commission permission to pursue acquisition of Southern California Edison's ("SCE") current ownership interest in Four Corners Units 4 and 5 and to retire Four Corners Units 1-3 (the "proposed Four Corners transaction"). Pursuant to Section 10.2, the Settlement does in fact state that upon execution of the Four Corners Transaction APS may within ten (10) business days after any Closing Date but no later than December 31, 2013, file an application with the Commission seeking to reflect in rates the rate base and expense effects associated with the acquisition of SCE's share of Units 4 and 5, the rate base and expense effects associated with the retirement of Units 1-3, and any cost deferral authorized in Docket No. E-01345A-10-0474. In its January 9, 2012 letter to the Commission, APS estimates that the Four Corners Transaction will increase the average residential bill by an additional 3.2% beyond the 3.5% that it forecasts to occur due to the PSA reset.

In summary, as shown in the January 9, 2012 letter to the Commission, APS forecasts that because of the Settlement the average residential bill will increase from $130.95 to $138.45 for an overall change of 5.7%. While I recognize the forecasting of fuel costs is fraught with uncertainty and there is no certainty that the Four Corners Transaction will take place, I do believe that the record in this case should be complete as to what the true rate impacts could be. This is important in that the Commission has final approval of the terms of the Settlement and can take steps to minimize what it perceives as undue rate impacts resulting from the Settlement.

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

A. Yes, it does.

ARIZONA PUBLIC SERVICE COMPANY

SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION

PRESENT AND PROPOSED RATES

TEST YEAR ENDING DECEMBER 31, 2010 ADJUSTED

| Line No. | (A) Customer Classification and Current Rate Designation | (B) Average Number of Customers | (C) Adjusted MWh Sales | (D) Average Annual kWh Usage per Customer [(C) x 1000] / (B) | (E) Base Revenues under Present Rates[1] ($000) | (F) Proposed Rate Designation | (G) Proposed Revenue: Base Revenues ($000) | (H) Proposed Revenue: Transmission Revenue[7] ($000) | (I) Proposed Revenue: Total Revenue ($000) | (J) Change - Base Rates: Amount ($000) (I) - (E) | (K) Change - Base Rates: % (J) / (E) | Line No. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Residential | | | | | | | | | | | 1 |
| 2 | E-12 | 485,397 | 4,026,662 | 8,296 | 493,366 | E-12 | 492,152 | - | 492,152 | (1,214) | -0.25% | 2 |
| 3 | ET-1 | 293,620 | 4,344,033 | 14,795 | 480,986 | ET-1 | 481,090 | - | 481,090 | 104 | 0.02% | 3 |
| 4 | ET-2 | 123,038 | 1,919,486 | 15,601 | 266,039 | ET-2 | 266,172 | - | 266,172 | 133 | 0.05% | 4 |
| 5 | ECT-2 | 39,448 | 1,400,862 | 35,512 | 107,426 | ECT-2 | 107,539 | - | 107,539 | 113 | 0.11% | 5 |
| 6 | ECT-1R | 48,378 | 1,404,939 | 29,041 | 122,096 | ECT-1R | 122,201 | - | 122,201 | 105 | 0.09% | 6 |
| 7 | ET-SP | 108 | 2,301 | 21,306 | 221 | ET-SP | 220 | - | 220 | (1) | -0.45% | 7 |
| 8 | Total Residential | 989,989 | 13,098,283 | 13,231 | 1,470,134 | Total Residential | 1,469,374 | - | 1,469,374 | (760) | -0.05% | 8 |
| 9 | | | | | | | | | | | | 9 |
| 10 | General Service | | | | | | | | | | | 10 |
| 11 | E-20 | 328 | 36,664 | 111,780 | 3,886 | E-20 | 3,912 | - | 3,912 | 26 | 0.67% | 11 |
| 13 | E-30 | 4,644 | 6,349 | 1,367 | 1,406 | E-30 | 1,407 | - | 1,407 | 1 | 0.07% | 13 |
| 14 | E-40 | 1 | - | - | 1 | See note 9 | | | | | | 14 |
| 15 | E-32 XS | 82,396 | 1,418,941 | 17,221 | 199,177 | E-32 XS | 203,014 | - | 203,014 | 3,837 | 1.93% | 15 |
| 16 | E-32 S | 29,411 | 2,551,983 | 86,770 | 290,021 | E-32 S | 292,939 | - | 292,939 | 2,918 | 1.01% | 16 |
| 17 | E-32 M | 4,425 | 3,279,542 | 741,139 | 317,315 | E-32 M | 317,809 | - | 317,809 | 494 | 0.16% | 17 |
| 18 | E-32 L | 1,035 | 3,647,139 | 3,523,806 | 303,798 | E-32 L | 301,465 | - | 301,465 | (2,333) | -0.77% | 18 |
| 19 | E-32 TOU XS | 78 | 4,609 | 59,090 | 633 | E-32 TOU XS | 644 | - | 644 | 11 | 1.74% | 19 |
| 20 | E-32 TOU S | 219 | 41,567 | 189,804 | 4,454 | E-32 TOU S | 4,484 | - | 4,484 | 30 | 0.67% | 20 |
| 21 | E-32 TOU M | 73 | 69,937 | 958,041 | 6,385 | E-32 TOU M | 6,374 | - | 6,374 | (11) | -0.17% | 21 |
| 22 | E-32 TOU L | 47 | 295,614 | 6,289,660 | 22,917 | E-32 TOU L | 22,625 | - | 22,625 | (292) | -1.27% | 22 |
| 23 | E-34 | 36 | 1,086,047 | 30,167,972 | 80,597 | E-34 | 79,328 | - | 79,328 | (1,269) | -1.57% | 23 |
| 24 | E-35 | 29 | 1,673,369 | 57,702,379 | 112,009 | E-35 | 109,345 | - | 109,345 | (2,664) | -2.38% | 24 |
| 25 | Total General Service | 122,722 | 14,111,761 | 114,990 | 1,342,599 | Total General Service | 1,343,346 | - | 1,343,346 | 748 | 0.06% | 25 |
| 26 | | | | | | | | | | | | 26 |
| 27 | Irrigation and Water Pumping | 1,450 | 313,308 | 216,074 | 26,669 | Irrigation and Water Pumping | 26,681 | - | 26,681 | 12 | 0.04% | 27 |
| 28 | | | | | | | | | | | | 28 |
| 29 | Outdoor Lighting | | | | | | | | | | | 29 |
| 30 | E-58 | 624 | 33,212 | 53,224 | 10,107 | E-58 | 10,107 | - | 10,107 | - | 0.00% | 30 |
| 31 | E-59 | 293 | 93,502 | 319,119 | 9,701 | E-59 | 9,701 | - | 9,701 | - | 0.00% | 31 |
| 32 | Contract 12 | 41 | 11,496 | 280,390 | 1,013 | Contract 12 | 1,013 | - | 1,013 | - | 0.00% | 32 |
| 33 | E-67 | 181 | 3,432 | 18,961 | 178 | E-67 | 178 | - | 178 | - | 0.00% | 33 |
| 34 | Total Outdoor Lighting | 1,139 | 141,642 | 124,356 | 20,999 | Total Outdoor Lighting | 20,999 | - | 20,999 | - | 0.00% | 34 |
| 35 | | | | | | | | | | | | 35 |
| 36 | Dusk to Dawn Lighting | See Note 5 | 24,613 | See Note 5 | 8,457 | Dusk to Dawn Lighting | 8,457 | - | 8,457 | - | 0.00% | 36 |
| 37 | | | | | | | | | | | | 37 |
| 38 | Total Sales to Ultimate Retail Customers | 1,115,300 | 27,689,607 See Note 10 | 24,827 | 2,868,858 | | 2,868,857 | - | 2,868,857 | - | 0.00% | 38 |

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues based on rates established in Decision No. 71448.
2) Share the Light Rate Schedules are included in Rate Schedule E-58.
3) Rider rate schedules are included in the "Parent" rate schedules listed on schedule H-2 as applicable.
Riders include: E-3, E-4, CPP-RES, CMPW-01, E-53, E-54, RSSP, PPR, CPP-GS, Solar-2, Solar-3, GPS-1, GPS-2, GPS-3, EPR-2, EPR-6, E-56, and SC-S.
4) Rate Schedule E-36 is not included as proposed price changes are market-related.
5) Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.
7) Transmission revenues based on OATT charges effective during test year.
8) Rate Schedules GS Schools M, GS-Schools L have no revenue or customers.
9) Rate E-40 proposed revenue is reflected in E-32 M
10) Excludes 144,149 MWh of revenue credits, total sales with revenue credits = 27,833,756 MWh

Supporting Schedules:
N/A