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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-08-0172

Arizona Corporation Commission
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NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Rate Design Testimony of Ben Johnson, Ph.D. in the above-referenced matter.

RESPECTFULLY SUBMITTED this 9th day of January, 2009.

Daniel W. Pozefsky
Chief Counsel

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ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-08-0172

DIRECT RATE DESIGN TESTIMONY

OF

BEN JOHNSON, PH. D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 9, 2009

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. 01345A-08-0172

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Are you the same Ben Johnson that filed revenue requirements testimony on December 19th, 2008?

A. Yes, I am.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, I have prepared Schedules BJ-15 through BJ-17. These schedules are attached to my testimony.

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

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of Arizona Public Service Company's ("APS") Amended Application for a base rate increase. The purpose of my testimony is to present RUCO's cost of service and rate design recommendations in this proceeding.

Following this introduction, my testimony has five sections. In the first section, I briefly discuss the background of this phase of the proceeding. In the second section, I summarize APS' cost of service methodology and rate design proposals. In the third section, I discuss fully allocated cost of service studies, focusing on methods that are available to allocate production costs. I also critique the Company's Average and Excess Demand methodology, and recommend an alternative approach to allocating production costs. In the fourth section, I discuss factors that should be considered in developing an appropriate revenue distribution. I also critique the Company's proposed rate design, and recommend an alternative revenue distribution approach. In the fifth section, I discuss some miscellaneous rate design issues.

I. Background

Q. Can you briefly discuss the rate design aspects of APS' most recent rate case?

A. Yes. APS' current rates became effective July 1, 2007 pursuant to Decision No. 69663 issued in Docket No. E-01345A-05-0816. APS conducted a cost of service study with a 12 month test period ending September 30, 2005. [Decision No. 69663, p. 69] The primary issue with respect to APS' cost of service study was the Company's use of the Four Coincident Peak (4CP) method of allocating demand-related production costs. [See, Id., p. 69] APS' 4CP method allocated production and transmission demand costs to customer classes using the average summer (June, July August and September) coincident system peaks.

The Commission Staff recommended using instead a combination of the Four Coincident Peak and Average Demand (4CP & Average). [Id.] Staff's 4CP & Average approach used a combination of APS' peak demand allocation factor and an average demand factor (which is mathematically equivalent to energy). [Id.] APS opposed Staff's approach, arguing that changing methodologies could subject some customers to rate shock. AECC also opposed Staff's approach, arguing that average demand is already included in peak demand, and therefore is counted twice in the 4CP and Average method.

Q. What did the Commission conclude with regard to cost of service?

A. The Commission agreed with Staff that an energy-weighting method for allocating production plant would be appropriate for APS. [Id., p. 70] However, because of the concerns expressed by other parties, the Commission did not agree that the 4CP and Average method was the appropriate solution. Instead, the Commission ordered APS, in its next rate application to

> propose an energy weighting method that addresses the concerns raised in this case, and that will also consider the likely cost shifting that will be necessary as we determine the appropriate rate design in this case. [Id., p. 71]

Q. What did the parties propose with regard to rate design in the last rate case?

A. APS proposed spreading it's requested revenue increase roughly equally to the major customer classes, even though its cost of service studies supported greater increases to some customer classes, including the residential class. [See, Id., p. 71] Staff, AECC, the FEA and Kroger, to varying degrees, all recommended moving rates closer to the cost of service study results. RUCO noted that rates were moved towards cost of service in the preceeding rate case (2 years prior), and that since then, there had been numerous fuel-related increases. RUCO stressed the need for rate stability and continuity, and therefore recommended an evenly distributed rate increase. [Id.]

Q. What did the Commission conclude regarding rate design in the previous rate case?

A. The Commission essentially approved APS' rate design recommendation, with a few adjustments as proposed by other parties.

> It is clear from the results of all cost-of-service studies that there are subsidies in APS' current rate structure. This means that some classes of customers are providing a subsidy to others and that some customers in a class subsidize others in the same class. Several parties have recommended that the Commission begin to close that gap, and move rates closer to the class' cost-of-service now. We agree that some movement should be made in that direction, but given the fact that current rates have been in effect for only two years and they were designed to move rates closer to cost-of-service, we do not want to modify the current rate structure dramatically. Accordingly, given the level of revenues that we authorize herein, we will generally adopt the Company's rate design as modified by Staff and with the AECC proposal for transmission rate design as agreed to by APS, and the voltage discounts as proposed by the FEA. [Id., p. 76]

II. APS' Rate Design Proposal

Q. Can you now summarize APS' cost of service study in this proceeding?

A. Yes. APS conducted an embedded cost-of-service study using a test year ending December 31, 2007. [Rumolo Direct, p. 15] The test year results were adjusted for "known and measurable" changes, such as increased labor costs, and the rate increase that went into effect during 2007. Company witness Rumolo explains:

> Other APS witnesses sponsor a number of pro forma adjustments that were incorporated into the test year used during the cost-of-service study. APS witnesses Jason La Benz, Mr. Ewen, Mr. DeLizio and Mr. Kearns list, by rate base, revenue, and expense category, the monetized amount of each proposed pro forma adjustment. These amounts were then functionalized, classified, and allocated to the retail and wholesale customer classes as part of the process in performing the cost-of-service study. The adjusted test year cost-of-service study reflects each of the Company's proposed pro forma adjustments. [Rumolo Direct, pp. 16-17]

APS's cost study methodology is a multi-step process. First, costs were grouped into major accounting categories, such as Plant in Service or Operating & Maintenance ("O&M") Expense. [Id., p. 19] Second, each of these accounting categories were further disaggregated into the functional categories of Production, Transmission, and Distribution. Third, costs were then classified as Demand, Energy, or Customer related. Finally, allocation factors were used to assign the resulting disaggregated costs into the federal and state jurisdictions and into the various retail customer classes. [Id.]

Q. Can you expain the "functionalization", "classification" and "allocation" steps in a little more detail?

A. Yes. "Functionalization" attributes costs to the Production, Transmission, or Distribution functions. APS gives the example of the costs of building and operating the Company's power plants, which are attributed to the

Production function. [Id., p. 18] Transmission and Distribution both involve moving electricity from the production source to the end user; the difference between Transmission and Distribution relate to voltage levels (Transmission occurs at higher voltages) as well as distance and proximity to the customer (Transmission tends to occur over longer distances, from the generation source to the major populated areas, whereas Distribution primarily occurs over shorter distances within the populated areas, terminating at the end user's location). "Classification" involves making a judgment about the causative factors that drive the magnitude of the cost.

> [I]if a cost is driven by the amount of energy consumed, it is classified as Energy; if a cost is driven by the rate at which energy is consumed, it is classified as Demand; and if a cost is driven by the number of customers taking service on the APS system irrespective of either the demand or energy utilized, it is classified as Customer. [Id.]

"Allocation" involves applying factors (e.g., peak demand contribution, energy or customers) to spread the costs to particular jurisdictions, customer classes, and rate schedules. For example, energy costs are allocated by kilowatt-hour ("kWh") consumption to different customer classes. [Rumolo Direct, p. 18]

Q. How does APS allocate production costs?

A. APS used the 4CP method to allocate these costs to jurisdictions. That is, production related costs were allocated to the ACC and FERC jurisdictions in proportion to relative levels of usage (demand) during 4 hours -- the hour with the highest level of system-wide demand during each of the summer months. Unlike its filing in the prior case, within the ACC-jurisdiction, APS used a different method to further allocate these costs to the various retail customer classes. [Id., pp. 19-20] Mr. Rumolo explains the decision to use the Average and Excess Demand method (for the sake of brevity, sometimes refered to as the AED method) as follows:

> In Decision No. 69663, the Commission directed that APS use an energy-weighted method to allocate production demand costs – that is, the costs associated with the Company's nuclear, coal, and gas-fired generation facilities – among retail customer classes. The AED method is one of the most widely accepted energy weighted allocation methods. It allocates a portion of production costs based on a customer class's peak demand contribution and the balance on that class's energy-based or average demand contribution. In doing so, the AED allocation method considers the fact that APS's production facilities provide service during both peak and non-peak hours of the year but also recognizes that average demand is already included in peak demand, and thus avoids double-counting of a customer's average demand when allocating costs. [Id., pp. 20-21]

While this description is accurate as far as it goes, it does not provide a complete picture of the AED method, or how it differs from the average and peak method which was recommended by the Staff in the prior case. I will discuss this in greater depth later in my testimony.

Q. How does APS allocate transmission costs?

A. APS directly assigned transmission plant to the non-ACC jurisdictional portion of the cost of service study, despite the fact that nearly all of this equipment is being used to serve retail customers. [Id., p. 20] Mr. Rumolo explains:

> Consistent with the methods adopted in our last rate cases, the revenue requirement for transmission services was computed based on the FERC-jurisdictional rates found in the APS Open Access Transmission Tariff ("OATT"). ... The APS OATT provides the class rate elements for each of the FERC-regulated transmission and ancillary service costs. Under the requirements of Decision No. 69663, the APS retail rates were re-structured so the transmission component of the rates reflect the OATT charges. [Id., pp. 23-24]

In this case APS is removing recovery of transmission costs from base rates and instead proposing to charge retail customers for transmission through a separate rate schedule, TCA-1, "that would directly incorporate by reference the Company's then-effective OATT charges.". [Id., p. 24]

> Effectively, the new TCA-1 will reflect the transmission cost found in base rates today, plus the then-effective adjustment that reflects the increased OATT charges. When the FERC-regulated transmission rates are changed, APS will refile the retail transmission rate schedule TCA-1 with the new charges. The existing TCA Plan of Administration will no longer be needed. [Id.]

The effect of Decision No. 69663 was to effectively let the FERC determine the transmission-related portion of the retail rates, including the rate of return to be earned on the transmission investment. This proposal goes a step further and requires retail customers to pay rates that are effectively set by the FERC. The result is that any future rate increases implemented by the FERC will be reflected in retail customer bills.

Q. How does APS allocate distribution costs?

A. APS used the "non-coincident peak" ("NCP") method to allocate costs associated with distribution substations and primary distribution lines. Allocations of costs related to distribution transformers and secondary distribution lines "are made based on the summation of the individual peak loads or demands of all customers within a particular customer class ("ΣNCP")." [Rumolo Direct, p. 20]

Q. How does APS allocate fuel and purchased power costs?

A. APS used a method recommended by another party in the previous rate case.

> [I]n our last rate case, an intervenor witness suggested the adoption of an hourly allocation method to allocate fuel and purchased power costs. ... The hourly energy allocation method examines customer class hourly load shapes and hourly energy prices to come up with a weighted energy cost. This weighted energy cost better matches each customer class's revenue responsibility with costs. For example, a customer class that uses more of its energy during peak summer hours should be allocated higher average fuel and energy costs than a customer class whose energy consumption is more off peak. [Id., p. 21]

Q. How does APS summarize the results of its cost of service study?

A. APS notes that disparities in the achieved returns by customer class have "decreased due to the rate designs implemented as a result of the rates implemented by previous ACC decisions ..." However, APS claims the residential class continues to provide a lower rate of return to the

Company than does the general service class. [Id., p. 23] Specifically, APS contends that under current rates and adjusted operating expenses, "the residential class rate of return is 2.85% while the general service class rate of return is 5.04%. Overall, the retail rate of return on an adjusted original cost rate base under current rates is 3.79%." [Id.]

Q. Can you now summarize APS' rate design methodology?

A. In designing its proposed rates, APS considered the cost of service study, as well "several other factors" such as rate and revenue stability and continuity. [Delizio Direct, p. 16]

> For this reason, the major classes of customers, including Residential, Street Lighting and Dusk to Dawn, have each been given a percentage increase to make the classes more in line with its cost of service even though strict adherence to the results of the cost of service study would indicate higher increases are supportable. General Service and Irrigation have each been given a lower increase to make the class more in line with its cost of service. APS has also taken steps to disaggregate its E-32 rate as required by Decision No. 69663 to make the rate more in line with its cost of service. That being said, the individual rate schedules have been designed to depart from strict cost of service adherence as necessary, so that differences in the increases that individual customers will experience will be moderated to the extent reasonable. [Id.]

APS' rate design results in the following revenue increases per customer class.

Class	Revenue Increase
Residential	11.34%
General Service	9.71%
Irrigation and Water Pumping	4.46%
Outdoor Lighting	15.05%
Dusk to Dawn Lighting	17.30%

III. Fully Allocated Embedded Costs

Q. Let's turn to the next section of your testimony. Can you provide a brief description of fully allocated embedded cost studies, and explain what they measure?

A. Certainly. Fully allocated cost of service studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the rate of return earned from each class. Many of these costs are either joint or common costs not directly attributable to any one customer class; therefore, they must be allocated by a formula. This opens the door to subjective judgments, and the results of the study tend to depend heavily on the particular allocation formulas chosen by the analyst.

Because they are based upon embedded costs, these studies do not report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" is not necessarily the actual expense that a particular group of customers imposes on the system. Nevertheless, cost of service studies have long been used by this Commission and others regulators as a tool that can assist with the process of developing electric and gas rates. As long as their limitations are recognized, and reasonable allocation formulas are employed, fully allocated cost studies can help the Commission in determining an appropriate revenue distribution.

Q. Can the judgment and arbitrariness be eliminated, if the analyst is completely unbiased and if sufficient effort is applied to the task?

A. No. The problem lies neither with the people performing the studies nor with the amount of effort and resources devoted to the analysis. Rather, it is inherent in the very concept of allocating embedded costs. To a large degree, these costs are the result of management and engineering decisions, which reflect many different considerations, are completely outside the control of individual customers or customer classes, and thus cannot be unambiguously traced to customers. While the goal may be to insure that each customer class pays the costs that it causes, it simply isn't possible to achieve this result by allocating historical accounting costs.

Even when the actions of particular customer classes do influence such decisions, the linkage is largely indirect, and is obscured by the passage of time. Admittedly, customers have influenced the production plant costs incurred during the test year. But (with the partial exception of fuel costs) these influences are almost entirely traceable to customer actions (and subsequent management decisions) that occurred 5 to 20 years ago, when the generating plants were planned and constructed. Hence, the cause and effect links between customers and test year costs are inherently impossible to measure through the techniques used in developing an embedded cost of service study. All of the various alternative allocation formulas rely upon statistics relating to the test year, and none of them can possibly reflect with exactness the historic relationships of cause and effect that explain the embedded accounting costs reflected in the test year data.

For these and other reasons, there is no "perfect" formula for allocating production plant costs. The same is true for most of the Company's other costs, including those of transmission and distribution. Some cost allocation experts will sometimes imply their approach is the "true" answer, and that any significantly different approach is a heresy not to be condoned. I disagree with that viewpoint. There is no "correct" method for allocating joint and common costs, and any attempt to locate it will ultimately prove fruitless.

Embedded cost allocation studies are simply a technique for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At best, these studies provide a yardstick for judging whether or not each customer class is paying an appropriate share of the joint and common costs. The real question is whether the yardstick is reasonably straight and true, or whether it is bent to favor particular classes at the expense of others. In that sense, it is meaningful to debate whether some approaches are more reasonable than others.

Aside from the long lags that occur between when costs are planned and incurred, and when they are recovered through rates, there is another fundamental problem. Most of the Company's embedded costs are not caused by the actions of particular customers or customer classes; rather they are incurred by management based upon an evaluation of the needs of the system as a whole. Thus it isn't feasible, or meaningful, to rely entirely on an evaluation of causal relationships in deciding on the most reasonable allocation method.

Consider, for example, an investment in which 10% of the cost can be meaningfully traced to customer classes and the remaining 90% is attributable to factors like fluctuations in the weather and fundamental characteristics of the geography of the Company's service territory. It is not necessarily reasonable to allocate 100% of the investment solely on the basis of the 10% that is logically traceable to customers. Furthermore, given the impossibility of identifying and measuring causative factors precisely, even this 10% of the total cost might be misinterpreted and traced to the wrong classes.

In evaluating the relative merits of different approaches, I believe it is important for the Commission to give adequate recognition to the basic product being sold by APS: electrical energy. Any allocation method that slights the importance of the most fundamental measure of the Company's output (kilowatt hours of electricity) should be viewed with skepticism. Where there is no clear cause-and-effect relationship between customer actions and costs, kWh sales provides a reasonable basis for allocation, because they closely reflect the benefits received by each class from the investments and expenses in question.

Q. Can you please discuss the methods that are available for allocating production related costs?

A. There are several methods that can be used; with regard to the investment in generating plants, most allocation methods use one, or a combination, of the following elements: coincident peak responsibility, non-coincident peak responsibility, average demand and excess demand. The most common methods are those based on coincident peak or average and excess demand (AED). As I explained earlier, the Company used a variant of the coincident peak methodology (4CP) to allocate production costs to the ACC and non-ACC jurisdictions, and the AED method to allocate retail costs among the ACC customer classes.

Q. Would you briefly explain the coincident peak allocation approach?

A. Yes. There are several different versions of the coincident peak approach. All of these methods allocate costs based on participation in system-wide coincident peaks. That is, during the hours when the system reaches its greatest demand, each load's portion of that demand is determined, and this becomes the basis for allocation. One method focuses on the hour during each month in which the maximum level of demand is experienced, then averages the results of these 12 different hours. This is sometimes referred to as a "12 CP" method. When this logic is taken to the extreme, it focuses on the single hour during the year when the highest CP is experienced. This is called the "1 CP" method. Anther variant is the "2 CP" method, which typically focuses on the maximum summer hour, and the maximum winter hour, whenever those happen to occur. Another option is the 4CP method, which is similar to the 12 CP method, except that it focuses exclusively on the four summer months with no consideration of usage characteristics during any other months of the year.

From an economic standpoint it is apparent that a utility does not simply design its generating system to meet the coincident peak demand, regardless of whether one focuses on 1, 2, 3, 4, or 12 hours of each year. Yet, this is the underlying basis of the various CP allocation methods. In reality, when designing the system, management is also concerned with system reliability, fuel costs, ability to generate energy, fuel diversity, operation and maintenance expenses, and geographic characteristics. If design decisions were based exclusively on the need to meet coincident peak demands, the utility would only build peaking units, because this would be the most cost-effective means of building a system that only needs to fulfill demand during during just 1, 2, 3, 4 or 12 hours of the year.

In reality, the Company's generating plant investment includes a wide variety of different technologies, including nuclear and coal fired generators and combined cycle plants. In fact, combustion turbines represent a relatively small share of APS's investment in generating plant. APS's combustion turbine plants represent only approximately $381 million in installed investment, while the Company has invested nearly $4 billion in nuclear and coal fired steam plants. Given the magnitude of APS' investment in nuclear and coal plants, they are of crucial importance in evaluating the reasonableness of alternative production cost allocation options.

From an economic perspective, the presence of these base-load plants, rather than just peaking plants, is strong evidence that factors other than peak demand have strongly influenced the Company's production-related investment decisions. The selection of coal and nuclear technology is primarily justified by the desire to achieve greater reliability and lower fuel costs than could be achieved if cheaper gas-fired combustion turbines were relied upon exclusively. Both of these factors (fuel cost savings and increased reliability) are related to the need to supply customers with energy throughout the year, and are largely unrelated to the timing or magnitude of system peak demand requirements.

Upon closer examination, it is clear that the great majority of a baseload plant's capital costs can logically be attributed to energy sales as opposed to peak demand or kW capacity. For instance, suppose it costs $1,000/kW to build a baseload coal plant and $250/kW to build a combustion turbine. Of the $1,000/kW of the coal plant's fixed capital cost, at most $250/kW, or 25%, can be logically attributed to peak demand requirements. Logically, the remaining $750/kW, or 75%, was incurred in an effort to achieve lower fuel costs, improved fuel diversity (lower risk of fuel price volatility) and greater reliability. All of these explanatory factors relate to the need to meet energy requirements throughout the year, rather than the need to serve the system load during a few peak hours of the year.

Base-load plants provide more favorable kWh-generating characteristics, but these beneficial characteristics are costly. For instance, by introducing steam boilers into the process used to convert the fuel into electrical energy, the engineers can reduce the amount of fuel which must be burned, per kWh generated. However, steam boilers are costly. Similarly, additional investments are required in order to burn coal, relative to natural gas; however, the additional investment is worthwhile because coal tends to be somewhat cheaper per BTU, relative to natural gas, and it is less volatile – offering greater fuel cost stability. Similarly, combined cycle plants tend to be more complex, and more costly to construct than combustion turbines, but they are more energy efficient, and thus can generate large volumes of energy at lower costs per-kWh than a pure peaking plant.

Because the Company must generate kWhs during many hours of the year (not just during the peak hours), a base-load or combined cycle plant is more economical on a cost per kWh basis, when everything is considered (not just peak demand). These cost savings heavily influence the Company's plant investment decisions, yet those savings are a function of kWh sales, not of peak kW demand during a handful of hours.

A pure CP allocation approach does not recognize causal relationships which explain much of the Company's investment in generating plants. The pure CP approach ignores the importance of energy efficiency, fuel diversity, and other factors, which are at least equally important as peak demand in the overall decision making process. Nor does the pure CP approach assign any cost responsibility to classes which happen to be off the system at the time of the coincident peak, even though these classes impose a regular recurring demand on the system, and gain great benefit from it.

Q. Would you please describe the Average and Excess Demand method?

A. Certainly. There are several variations of the AED method, but I will concentrate on the most common. The first portion of the allocation, the average demand, can be derived by multiplying the non-coincident peak demand for each load by its associated load factor. Consider a simplified system consisting of four classes. As shown on Schedule BJ-15, Class A has a 50 kW load that runs at all times. Class B has a maximum load of 100 kW, and a load factor of 50%; it does not operate during the system coincident peak hours. Class C is similar, with a maximum load of 100 kW, and a load factor of 50%; however, 75kW of its load is present when the system coincident peaks occur. Finally, Class D has a 25% load factor; its coincident peak load is 150kW, and its non-coincident peak (NCP) is 200kW.

The system CP demand in this example equals 275 kW and the sum of the NCP demands equals 450 kW. The average demand would equal 50 kW in each case, with the system average demand totaling 200kW. The excess portion is determined by subtracting the calculated average demand from the non-coincident peak demand. In this example, total excess demand equals 0 kW, 50 kW, 50kW, and 150 kW, for classes A, B, C and D, respectively.

In the Average and Excess method, total excess demand for each load is typically allocated in a way that ensures the total system average and excess demand equals the system coincident peak demand. The formula for the allocated excess demand for load (B) would look like this:

((B)Excess/System Excess)*(Sys CP-Sys Ave) or (50/250)*(275-200) = 15kW. Load (B)'s average and excess demand then equals 50 + 15 or 65 kW. In turn, each load or class would be allocated a share of the system generating costs, based upon its proportionate share of the calculated average and excess demand.

In this example, the respective average and excess demands would be as follows: Load A 50kW, Load B 65kW, and Load C 65kW, Load D 95kW. In turn, Load A would be allocated 18.2% of the costs, Load B would be allocated 23.6%, Load C would be allocated 23.6%, and Load D would be allocated 34.5%.

The AED approach assumes that part of a utility's plant investment is a response to (or should be allocated on the basis of) the average demand (or kWh consumption) on the system throughout the year, and the remainder is a response to (or should be allocated on the basis of) the difference between average demand and the individual NCP of each class. Simply stated, I agree with the first half of this reasoning, but not with the second half. To the extent that this approach acknowledges year-round energy sales as an influence on the design of the production system, it is somewhat responsive to the issues addressed in the last APS rate case. However, unlike the Average and Peak method recommended by the Staff in that case, the AED method does not consider the contribution of each class to the overall coincident system peak, and instead it places emphasis on "excess" demand, which is the mathematical difference between average demand and NCP, regardless of whether or not that individual peak occurs at a time when other classes are also imposing heavy loads on the system.

This calculated difference (called "excess" demand) is not closely related to the factors which cause a utility to incur generating and transmission costs, and it does not result in a more reasonable basis for allocating such costs than the average and peak method recommended by the Staff in the last case. This is true for two reasons. First, the design of generating systems is based less upon non-coincident peak than it is based upon coincident peaks. A utility like APS needs enough generating capacity to serve its coincident system peak loads; it does not need to build generating capacity to meet the individual non-coincident peak loads of the various classes.

To the extent these NCPs happen to exceed the average load of that class, or it's coincident peak, the additional load doesn't necessarily impose any additional costs on the system – particularly if the NCP happens to occur at a time when the demand imposed by other classes happens to be low. For example, street lighting customers might happen to experience their maximum individual NCP at night in the winter, at a time when ample excess capacity exists on the system, because other classes are using relatively little electricity at that time. In sum, there is no economic justification for using the "excess" statistic as a basis for determining the relative share of costs which should be borne by the various customer classes. Stated a bit differently, the distinctive aspect of the AED method – its reliance on the excess of NCP demand over average demand – is not well founded. Excess demand does not drive system design, and it does not yield an improvement over the Average and Peak method recommended by the Staff in the last rate case.

Q. Would you please elaborate on your explanation of why you don't believe the AED method is the best response to the concerns expressed by the Commission in the last case?

A. Yes. A portion of the plant investment is closely related to the need to generate electrical energy at minimum cost. Hence, there is merit to giving consideration to energy or "average" demand (which is mathematically equivalent to kWh) in the cost allocation process, as suggested in the last case.

The Company's study in this proceeding is somewhat responsive to the Commission's directive in the prior case, but I believe the AED method is not the optimal approach, because of its emphasis on "excess" demands, which do not sufficiently relate to the underlying economics involved in the production process.

Additional peaking capacity is needed in order to meet the higher load that occurs during the hottest days of the summer. However, the additional production and transmission costs that the Company incurs in order to serve demands that exceed the average demand are almost entirely related to fluctuations in the overall system demand, not fluctuations in the demand of individual customers or classes, or the "excess" of those demands over the class average. Thus, if an increase in demand by Class A is offset by a decrease in demand by Class B, these two fluctuations may cancel out, resulting in little or no need to build more peaking plants, or otherwise incur extra generation and transmission costs as a result of the demand fluctuations.

Under the Company's AED approach, a large fraction of the generating costs are allocated in accordance with each class's calculated excess demand (i.e., the NCP demand less the average demand of each class). The implicit premise is that "excess" costs (beyond those which would be incurred if every customer had a 100% load factor) must also be incurred, because of these excess demands. However, this reasoning is overly simplistic, and it ignores the many intervening factors that determine whether, and to what extent, fluctuations in individual loads impose any additional cost on the system as a whole. For instance, the AED method doesn't adequately consider the need to maintain generating plants, which can be scheduled during hours of the day, or months of the year, when load is below the peak levels.

The AED methodology implicitly assumes that all of the seasonal and daily load variations of classes with fluctuating demands is costly and detrimental to the system, imposing "excess" costs which must not be allocated to high load factor customers. In fact, a 100% load factor customer would have not "excess" demand, and thus would not bear any share of the costs that are allocated in proportion to excess demand. This is too extreme a view of the situation, however. To some extent, fluctuations in loads, as experienced by low load factor classes, such as residential and small commercial customers, are somewhat beneficial to the system, because they facilitate scheduled plant maintenance. For instance, the lull in demand which is typically experienced in the spring and autumn months allows the utility to schedule maintenance activities during this period. If the system did not have this periodic drop in demand, it would be necessary to build additional plants, which would be needed to maintain output while other units are being serviced.

If every class were to shift its load away from the peak periods, in order to achieve 100% load factors (holding kWh constant), the system capacity and generating costs could be reduced somewhat. But it would not be feasible to reduce costs to the full extent implied by the AED method. Any resulting savings would be far less than the level of "excess" costs which is implicitly assumed in the Company's AED methodology.

The AED method assumes that demands that are in "excess" of the average are costly to serve. While there is an element of truth in this assumption, the AED method greatly exaggerates the additional burden imposed by fluctuating demands. Among other reasons, it fails to recognize that peaker plants can serve "excess" demand at a lower cost per unit of peak capacity than the baseload plants that are used to provide energy, and because it fails to consider the fact that no generating plant is capable of running 24 hours a day, 365 days a year.

In fact, if every class maintained a 100% load factor, the Company would nevertheless have to install capacity beyond that required to meet the average demand. A set of base-load units sized to just meet the class demand would not be sufficient, because they would lack sufficient spare capacity for scheduled (or unscheduled) maintenance. Despite having a perfectly flat load, the Company would still need to install peaking plants, or combined cycle plants, in excess of the average (equals peak) demand on the system, in order to maintain reliability and allow for maintenance. Thus, if every customer class had a 100% load factor (NCP equaled Average Demand), costs would decline by far less than the portion of the total costs which is allocated using excess demand in the AED method.

The average and excess methodology essentially ignores this fact. Classes with a 100% load factor are completely exempt from helping to pay for the portion of the Company's production costs which is allocated using the "excess" allocation factor. In effect, the costs of "excess" capacity (beyond the average level of demand) are allocated almost entirely to low load factor customer classes, including the residential class. This is inequitable and inconsistent with the underlying economics of the production process. Hence, the AED method yields unreasonable results.

Q. Is there another problem with the Average and Excess method?

A. Yes. Another serious flaw is that the AED method completely ignores relative class contributions to the system coincident peak. Yet, the coincident peak is actually far more important than the NCP as an explanatory factor which influences production costs. To the extent a cost allocation method is supposed to reflect the factors which "cause" costs, it makes sense to give substantial consideration to coincident peak data, and it makes little sense to focus on non-coincident peaks. Because the AED method fails to give any weight to CP data, it treats customer classes with equivalent load factors the same, even if one class contributes to the system peak, while the other doesn't.

To illustrate this problem, consider again the hypothetical example I discussed above. Class B and Class C are both allocated 23.6% of the costs under the AED method. Yet, Class C is contributing to the system coincident peak, while Class B is not. A reasonable cost allocation method would give some consideration to this difference in circumstances, and allocate less cost to Class B, in recognition of its favorable off-peak characteristics.

Q. Have you developed an alternative to the Average and Excess formula?

A. Yes, I have. My recommended approach recognizes that the primary purpose of the Company's production plant is to provide energy used by its customers, and thus it gives considerable weight to energy (average demand). However, my recommended approach also recognizes that it is less costly to serve customers with high load factors (their use of energy occurs fairly uniformly throughout the day, 365 days a year), and customers who consume little or no energy during times when energy use is at a peak (e.g. street lighting, which occurs in the evening). These types of customers are allocated a relatively small share of the cost of production plant, while customers with loads that fluctuate in synch with the system are allocated a somewhat higher share.

Specifically, I recommend using a weighted blend of the average, 1CP and 4 CP demand statistics. This weighted allocation approach is similar to the one recommended by the Staff in the last case, but it is more closely tied to the specific mix of generating plants used by APS. It recognizes that the Company's kW demand varies from hour to hour and month to month, thus the contribution of each class to the system peak does influence generation costs, and should be considered in the cost allocation process. However, it also recognizes that most of the Company's production related investment is in baseload generating plants, which are designed and constructed for the purpose of providing energy throughout the year at the lowest feasible cost per kWh. The cost of these baseload production facilities should logically be allocated almost entirely in accordance with each class's kWh purchases.

Q. Can you please explain the general approach you used to develop this weighted blend of the Average, 1CP and 4CP demand?

A. Yes. I started by reviewing descriptive data for each of the Company's generating units, as shown on Schedule BJ-16. As shown on that schedule I grouped all of the APS generating units into three broad categories – baseload, mid, and peaking, based primarily on their operating cost per kWh generated (based primarily on the cost of fuel), and the extent to which the unit is operated throughout the entire year, or only during a small number of hours.

While there are variations in the design and efficiency of each of the units, the ones that I have classified as baseload plants share certain common characteristics. They are all operated close to their full name plant capacity during a high percentage of the days, and hours, of the year. I estimate the overall average rate of usage is about 76.5% -- which is close to the theoretical maximum possible, given the need to periodically take the Palo Verde units down for refueling, and the need to take units offline for both scheduled and unscheduled maintenance. Not only are these plants relied upon to generate energy throughout the entire year, they do so at relatively low cost per kWh, with fuel and other production expenses averaging just 2.6 cents per kWh.

At the other end of the spectrum, the Company has a group of plants that are designed and used for the purpose of serving the portion of the Company's electricity sales that occurs only during a limited number of peak hours, particularly the hot summer afternoons. The cost of providing energy during these peak hours tends to be higher than during other hours of the year, for several reasons, including the need to install additional generating capacity which is only needed for a relatively small number of hours each year – spreading the fixed costs of a generating unit over a small number of hours inevitably results in a high cost per kWh. In an effort to hold down these fixed costs, the Company has installed combustion turbines, which can be designed and installed quickly, and which cost less to construct than baseload plants. As shown at the bottom of Schedule 16, these peaking units are relatively costly to operate, with fuel and other production expenses averaging 7.9 cents per kWh, which is three times the cost of operating the baseload plants. However, these units are relatively inexpensive to construct.

Both combustion turbines and baseload plants enable a utility to serve the demand on its system. The key factor that determines the choice of technology (and fuel selection) is the overall effective cost, taking into account not only peak demand, but also the total volume of electricity that needs to be provided to customers. In order to reduce the cost of providing energy throughout the year, utilities like APS invest more upfront, in order to gain the benefit of lower fuel and other operating costs.

The data on Schedule 16 demonstrates these differences in construction and operating costs, although the pattern is somewhat obscured because different units were constructed during different time periods. As a result of inflation, technological changes, and changing environmental standards, the installed cost of a plant constructed in 1972 cannot be directly compared with one installed 30 years later. However, throughout the past 40 years, it has generally been the case that combustion turbines were less costly to install than coal and nuclear fired baseload plants. Large investments were made in coal and nuclear plants because they were expected to achieve lower operating costs on a per kWh basis over the life cycle of the plant.

This trade off can be readily seen by comparing 4 Corners Unit 4, which was constructed during the 1974-76 time frame with Yucca Unit 3 which was constructed during the 1973-74 time frame. This coal plant cost $748 per kW to construct, whereas APS was able to install Yucca 3 at a cost of just $174 per kW. When APS chose to spend more than three times as much to build a coal plant, it was not being irrational or imprudent – it was recognizing the need to provide energy throughout every hour of the year, and the importance of minimizing fuel costs in evaluating the most cost-effective way of serving this need.

During the test year, 4 Corners Unit 4 was operated at 80.5% of its theoretical potential (about the maximum rate possible, considering the need for maintenance), whereas the equivalent statistic for Yucca 3 was less than 2%. These operational differences are reflected in equally stark differences in the level of production expenses associated with these units. APS incurred expenses of just 2.4 cents per kWh generated by the coal unit, while it spent an average of 19.4 cents for each kWh generated by Yucca 3. Needless to say, these contrasting statistics are closely related to each other – while Yucca 3 was much cheaper to build, it is much more costly to operate, and thus it is only cost effective to use it during a relative handful of peak hours during the year.

The logic I used in developing my recommended approach to allocated production costs is straightforward. I began with the premise that the installed cost of peaking units should be allocated to customers in proportion to their usage during times when the overall system is experiencing peak usage. These particular generating facilities are needed to serve the extraordinarily high demand levels which occur during the system peak hours, and thus it is reasonable and logical to allocate the cost of peaking plants on the basis of class contributions to the system peaks. Since each customer class present during the annual peak contributes to the need for these peaking units, it is reasonable to allocate this portion of of the Company's production costs in proportion to coincident peak demand.

With respect to the cost of baseload generating plants, however, I reasoned that most of the cost is unrelated to peak capacity, since the equivalent capacity could have been constructed at a vastly lower cost per unit. Hence, I concluded that the installed costs of baseload plants are largely attributable to the need to generate energy – the additional investment is incurred in an effort to achieve a lower cost per kWh, and to diversify away from a single fuel source. Hence, it is more reasonable to allocate most of the cost of the baseload units on the basis of average demand or energy (they are mathematically equivalent).

Q. Can you please describe the specific calculations you used to develop your production allocation factor?

A. Yes. I started with the relative magnitude of the Company's investment (before depreciation) in baseload, mid and peaking plants, as developed in Schedule BJ-16. I then used these proportions in developing a blended allocation factor which gives substantial weight to Average demand, with less weight given to 4CP demand, and even less weight to 1CP demand. The resulting allocation factor effectively gives 62.83% weight to Average

Demand, 27.67% weight to 4CP, and 9.50% weight to 1CP. For the sake of brevity, this can be referred to as the A-4-1 method.

	Installed Cost	Average Demand	4 CP	1CP
Baseload	73.74%	80.00%	20.00%	0.00%
Mid	19.18%	20.00%	60.00%	20.00%
Peaking	7.08%	0.00%	20.00%	80.00%

Q. How does your recommended production allocation approach compare with the AED method?

A. I believe this weighted approach is conceptually superior to the average and excess method, while sharing all of its advantages over the pure 4CP method used in the the Company's last rate case. For instance, both approaches avoid focusing on a single statistic, and both use kWh (or its equivalent, average kW demand) as the single most important statistic used in developing a composite allocation factor. This avoids giving a completely "free ride" to any one customer class, and helps produce relatively stable cost-of-service study results over time.

However, my recommended method is superior to the average and excess approach in that it focuses on the contributions of each customer class to the system coincident peak demand, rather than focusing on non-coincident "excess" demand. Under my approach, all customer classes are assigned a share of the cost responsibility for the nuclear, steam and combined cycle plants used in providing energy to these customers. However, high load factor customer classes, and classes (like street lighting) that are largely or entirely absent during the system peak are assigned a smaller share of the production costs, consistent with the relative importance of peaking units in the overall generating mix.

Q. Have you developed any estimates of the impact of using different approaches to the allocation of production costs?

A. Yes, I have. For illustrative purposes, I developed two sets of alternative cost of service results. One uses the 4CP method used in the prior case, and the other uses my recommended approach, based on a weighted combination of Average, 4CP and 1CP statistics (the the A-4-1 method). The results are summarized on Schedule BJ-17, along with the results of the Company's proposed AED method. All of these calculations are based on the Company's revenue requirement filing, and thus the calculated returns are substantially lower than would be computed if I had started with RUCO's revenue requirement calculations.

As shown on Schedule BJ-17, there are both similarities and differences in the cost results. For instance, both the AED and the A-4-1 method tend to place some responsibility for production costs on the Street Lighting and Dusk to Dawn Classes, whereas the 4CP method used in the last case tends to absolve these Classes of any responsibility for the Company's generating plants – effectively giving them a free ride.

Relative to the 4CP method, the residential class generally shows somewhat higher returns, and the General Service class generally shows somewhat lower returns, under either the AED or the A-4-1 method, but the differences are slightly more pronounced under the A-4-1 method, as summarized in the following table, which summarizes some key results from Schedule BJ-17:

Rate of Return	AED	4CP	Average 4CP and 1CP
Residential	2.85%	2.68%	3.05%
General Service	5.04%	5.14%	4.67%
Irrigation	6.91%	15.95%	6.94%
Street Lights	-0.03%	2.17%	0.55%
Dusk to Dawn	6.61%	8.06%	7.01%

The AED and 4CP methods generate rates of return of 2.85% and 2.68% for the residential class, respectively. My recommended A-4-1 approach results in a modestly higher rate of return of 3.05% for residential customers as a whole. My proposed production allocation methodology results in an overall rate of return of 4.67% for the General Service class, compared to 5.04% and 5.14% for the AED and 4CP methods, respectively.

At this level of summarization, the most dramatic difference in returns are for the Irrigation class, which shows a return of just 6.91% using the AED approach and a nearly identical 6.94% using the A-4-1 approach, but a 15.95% return using the 4CP approach. The Street Lighting class also shows widely varying returns, ranging from -0.03% using the AED approach, .55% using the A-4-1 approach, and 2.17% using the 4CP approach. Bear in mind that this table only illustrates the impact of differences in production cost allocation methods, and it rolls together multiple rate schedules within the Residential and General Service classes.

If other aspects of the study were also varied, or variations in individual rate schedules were displayed, even wider variations in the rates of return would be displayed.

As shown in BJ-16, the results for some individual rate schedules differ significantly from these general patterns. For instance, Rate Schedule E-20 (Church Service) shows a return under A-4-1 that is slightly higher than under the 4CP method, whereas it shows a sharply lower return under the AED method. This is probably a consequence of the AED method's excessive emphasis on "excess demands" relative to the individual non-coincident peak, which would adversely impact churches that experience their peak load during the morning hours, although the system as a whole is not peaking at that time. Similarly, the E-32 General Service Rate Schedule shows a higher return under the A-4-1 method, and a lower return under the AED method, relative to the 4CP method.

IV. Revenue Distribution

Q. Let's turn to the fourth section of your testimony. What factors do you think should be considered in developing the interclass revenue distribution?

A. I recommend giving some consideration to the cost of service results – particularly the A-4-1 results, since I believe those are the most reliable and meaningful. Further, some limited consideration should also be given to the 4CP results, since that was the method relied upon in the prior rate case. However, I think other factors are also important in developing a fair and reasonable revenue distribution, including historical rate relationships, ability to pay, relative risk, and demand or market conditions (including the extent of any retail competition that might exist).

It is sometimes argued that the revenue burden should be distributed among the classes based entirely upon the results of a particular class cost-of-service study, at least as a goal. This argument has grown in popularity as "cost-based" ratemaking has come into vogue. However, I fundamentally disagree with this philosophy, particularly when it is tied to a single embedded cost allocation study. Valid cost-of-service studies can provide a useful starting point in developing the overall revenue distribution; but even if the cost study itself isn't controversial, the ultimate determination of rate spread should be tempered by consideration of other factors, such as the ones I just enumerated.

Any proposal to move away from the existing rate relationships should be implemented gradually. This is particularly important in a case like the present one, where the cost allocation methods are a matter of controversy, changes in the allocation methods are being proposed by various parties, and there is relatively little information available to evaluate how the various allocation methods react to changing weather and economic conditions, and thus little is known about how the various class returns react to changing conditions in the future.

In any event, the revenue distribution should not be designed merely to track the results of a particular cost-of-service study. Instead, thought should be given from the outset to the potential hardships imposed on particular classes, historical relationships among the classes, and other elements of interclass equity. Moreover, the Commission should recognize that efforts to achieve uniform class rates of return are mostly fruitless. Even if a consistent COS methodology is employed from case to case, minor fluctuations in weather, economic conditions, and other variables can easily produce absolute fluctuations in the class rates of return of 1%-4% or even more, defeating such an attempt at uniformity. If an above-average increase is imposed in one case (because a class appears to earning less than the average return), a below-average increase may appear appropriate in the very next case, simply because of minor fluctuations in weather or usage patterns – even if the underlying methodology is not changing. Of course, where changes in the costing methodology are involved, the class returns can fluctuate by even wider margins, due simply to differences in allocation techniques.

Given the inherent instability and subjectivity of the various allocations, the goal of absolute uniformity in class rates of return can probably never be achieved. Such an effort is an attempt to hit a moving target, and that very effort can potentially conflict with important policy objectives, like rate continuity, gradualism and stability.

Q. How has the Company proposed to distribute its proposed revenue increase among the various customer classes?

A. The Company is proposing different percentage increases for the various customer classes, in an effort "to make the classes more in line with its cost of service ..." Of course, this goal of increased uniformity is mathematically dependent on the specific allocation procedures used in its latest study, including the AED method, which has not previously been accepted, and which I recommend not be accepted. If different allocations were used, the proposed revenue distribution wouldn't necessarily represent a movement toward greater uniformity of returns.

The following table shows APS' estimated rates of return by customer class associated with the Company's current rates and proposed rates, based on the Company's cost allocations. The proposed rate changes range from a low of 4.46% for the Water Pumping class to a high of 17.30% for the Dusk to Dawn Lighting class. This wide range reflects the Company's efforts to respond to the results of its cost-of-service study, based on the assumption that rates should be more consistent with these cost allocation results. As shown, the residential rate of return would more than double under the Company's proposed rates, while the return generated by the Outdoor Lighting class would quadruple.

Class	ROR Current Rates	ROR Proposed Rates	Revenue Increase
Residential	2.85	7.62	11.34%
General Service	5.04	10.55	9.71%
Irrigation and Water Pumping	6.91	13.19	4.46%
Outdoor Lighting	-0.03	3.15	15.05%
Dusk to Dawn Lighting	6.61	9.69	17.30%
Total	3.79	8.86	10.55%

Source: Schedules G-1, G-2, H-2

Q. What is your reaction to APS' proposed revenue distribution?

A. I disagree with the Company's proposed revenue distribution, for three reasons. First, the Company is attempting to move toward unformity of returns under its most recent cost allocation study – an alignment which is neither desirable nor necessary. Second, some of the proposed rate changes are excessive. Even if Dusk to Dawn Lighting rates ought to be increased relative to other rates (which isn't necessarily true) an increase of 17% is clearly excessive. Third, the Company's cost study suffers from serious deficiencies, as I discussed earlier. Because of these deficiencies, it does not provide the most reasonable basis for evaluating the existing rate relationships or for developing a more appropriate revenue distribution. The specific returns earned by each of the classes depends in large part on the assumptions and allocation techniques adopted in the cost-of-service study. Different conclusions would be reached if a different allocation study is used as a benchmark for evaluating the existing rate relationships.

Q. Have you evaluated the Company's proposed revenue distribution in light of your recommended Cost of Service results?

A. Yes. In some instances the Company is proposing above average increases for customers who are already generating returns near, or above, the system average. For instance, Dusk to Dawn is earning a return of 7.01% under the A-4-1 approach and 8.06% under the 4CP approach, yet the Company is proposing to increase rates by 17.30%, which is substantially higher than the overall average increase.

Similarly, the Company is proposing below-average increases for some Rate Schedules that currently show a relatively low rate of return using the A-4-1 approach, suggesting an attempt to move toward uniformity of returns under the AED approach which directly conflicts with the analogous goal under the A-4-1 approach. For example, the Company is proposing a 7.62% increase for schedule E-34 (General Service-Extra Large), yet this rate schedule is only generating a 1.13% rate of return using the A-4-1 approach, and just a 3.00% return using the 4CP approach. These examples demonstrate that some of the Company's rate proposals could actually move away from the goal of uniform returns.

Q. Have you developed an alternative revenue distribution approach which you are recommending to the Commission?

A. Yes, I have developed an alternative methodology which gives considerable weight to historic rate relationships, while also giving some consideration to the cost of service results.

Specifically, starting with the results of my recommended cost of service study, I looked for rate schedules with rates of return significantly above or below the system average. I then checked to see how the return compares to that generated using the 4CP method used in the prior case. Where the 4CP study confirms the existence of a return that is above or below the system average, I recommend giving a corresponding below- or above-average percentage rate increase. If a rate schedule currently generates a return that is reasonably close to the system average, I recommend giving the rate schedule an increase that is approximately equal to the overall average increase. Where my recommended cost of service results differ greatly from both the system average and the results using the 4CP method approved in the prior case, I suggest a more cautious approach, applying a rate change that is the same as, or just modestly different from, the overall system average.

In order to avoid inter-class inequities, and in recognition of the fact that cost allocation studies are not perfectly precise, I believe that none of the classes should receive percentage rate increases that differ dramatically from the overall system average. The approach I have just described gives reasonable weight to the cost of service results, moving some of the class returns toward the average, without fine-tuning the returns in a futile attempt to move toward complete uniformity. My specific recommendations are as follows:

First, the following rate schedules have returns that are substantially lower than the system average of 3.79%: Residential rates EC-1 Residential

Service with Demand Charge-Old (-1.97%), ECT-1R and ECT-2 Time of Use with Demand Charge (-.69%), E-10 Residential Service-Old (-.41%), as well as rates E-34 General Service-Extra Large (1.13%), General Service E-20 Church Rate (2.19%), and Street Lighting (.55%). In all of these cases, the 4CP cost allocation study confirms these rate schedules are generating below-average returns (although the extent of the discrepancy isn't necessarily the same). Hence, I recommend increasing these particular rate schedules by a moderately higher percentage than the overall system average increase (assuming the Commission is going to increase rates).

Second, the following rate schedules have returns that are substantially higher than the system average of 3.79%: Rate E-12 Residential Service New (5.78%), General Services rates E-32 (101-400 kW) (5.55%), E-32 (21-100 kW) (6.49%), Irrigation (6.97%) and Dusk to Dawn (7.01%). In all of these cases, the 4CP cost allocation study confirms these rate schedules are generating above-average returns. Hence, I recommend increasing these rates by somewhat less than the overall system average increase (assuming the Commission is going to increase rates).

Third, the remaining rate schedules have returns that are only moderately different from the system average of 3.79%: Residential rates ET-1 and ET-2 Time of Use (3.06%), General Service rates E-32 Time of Use (3.82%), E-32 401+kW (4.87%) and E-30 and E-32 0-20kW (5.11%). Since they are currently earning returns that are fairly close to the system average, I recommend increasing these rates by the system average increase. (No deviation from the system average is necessary or appropriate). For convenience, all of these specific recommendations are summarized in the last column of Schedule BJ-17.

The specific changes that would apply to each Rate Schedule, and the resulting average rate changes applying to each class will depend, of course, on the overall revenue requirement approved by the Commission. In the revenue requirements phase of this proceeding RUCO did not recommend any increase or decrease to rates. Hence, I have used a simple hypothetical example to illustrate the effect of my recommended revenue distribution approach. More specifically, I prepared the following table based on the hypothetical assumption that the Commission approves an overall rate increase of 10.0%, or $263.7 million (before considering PSA changes).

Class	Revenue Increase
Residential	4.28%
General Service	2.75%
Irrigation and Water Pumping	0.12%
Outdoor Lighting	8.90%
Dusk to Dawn Lighting	5.90%
Total	3.55%

In developing these illustrative calculations I used the PSA amounts reflected in the Company original rate filing.

V. Miscellaneous Tariff Issues

Q. Let's turn to the last section of your testimony. What other rate design issues do you wish to discuss?

A. I would like to comment on the Company's proposed residential time of use (TOU) rates and Impact Fees.

Q. Let's discuss the residential time of use rates. Can you please describe the Company's existing rates?

A. Yes. APS started implementing TOU rates in the 1980s. [Brandt Direct, p. 65] As of December 2007, 46% of total residential customers (61% of residential kWh sales) are participating in a TOU rate. [Delizio Direct, p. 26]

In fact, the majority of APS' active residential rate schedules (4 of 7) are TOU-based. [Delizio Direct, p. 23] The "Series 1" rates, ET-1 and ECT-lR, have a broad 12-hour on-peak period, from 9 a.m. to 9 p.m weekdays. The "Series 2" rates have a more narrowly targeted 7-hour on-peak period, from noon to 7:00 p.m. weekdays. [Delizio Direct, p. 25]

Q. What changes is the Company proposing with regard to residential TOU rates?

A. First, the Company is proposing to "freeze" the "Series 1" TOU rates (ET-1 and ECT- 1R) "to encourage participation in the Series 2 TOU rates and the new TOU rate proposal." [Id., p. 26] The effect of this "freeze" is to prevent any new customers from selecting the Series 1 TOU rate, without forcing existing customers off the rate.

Second, the Company is proposing a new residential TOU rate with a super peak price for the "most critical" summer hours. [Miessner Direct, p. 9]

> This rate will be similar to rate ET-2, with a 7-hour on-peak period, but will add a super peak price for weekday afternoons from 3:00 p.m. to 6:00 p.m. during June, July and August. The summer off-peak price will be discounted to off-set the higher super peak price. The customer has the opportunity to have lower monthly bills by reducing load during either the on-peak or super-peak periods, or both. It will be available to all residential customers who are served with advanced metering infrastructure ("AMI") meters. [Id.]

Q. What is your response to the Company's residential TOU proposals?

A. In general, the Company is to be commended for offering residential customers several TOU rate options, and for successfully marketing these rates. As a result, a majority of the residential customers are currently billed under a TOU rate, which provides them with more nuanced price signals, and provides them with an incentive to trim usage during the costly peak hours.

I would also note that the Company's "super-peak" proposal has merit, in that it offers customers an option of a more narrowly focused peak pricing plan, which primarily targets a relatively small number of hours during the summer, when the Company incurs the additional costs associated with combustion turbines. To the extent certain customers are willing to reduce their usage during these hours, the Company will be able to avoid the high cost of running its peaking plants. It is economically efficient to provide customers with price signals that are consistent with this underlying cost pattern. As well, if enough customers opt for this form of pricing, and if they are willing to curtail their usage during these peak hours, the Company will be able to avoid installing additional peaking capacity.

While I agree with the philosophy behind this proposal, I am not convinced the Company is going far enough toward aligning prices with the underlying cost patterns. In particular, I note that the proposed "super-peak" hours are uniformly applied throughout the summer months, rather than being more narrowly focused on the specific hours and days when the Company incurs the highest costs.

Mr. Miessner is proposing to offer a more highly targeted form of peak pricing to General Service customers, what he refers to as "critical peak pricing (CPP)." The CPP proposal targets a much smaller number of hours with much higher prices (offering a greater incentive for customers to reduce their usage during those hours). Not only is the CPP proposal focused on a smaller number of hours, it is more focused on the specific situations when costs are highest – the particular hours when the system is experiencing unusually high loads, or limited generating capacity, or both.

Rather than applying the CPP approach to residential customers, Mr. Miessner advocates using a broader "super-peak" approach because he believe it will offer lower implementation costs, and achieve higher customer acceptance. While this reasoning isn't implausible, neither is it self-evident that the more narrowly focused CPP approach is better suited for General Service customers than for residential customers.

To be fully effective, customers need to be informed of a "critical peak" shortly before it occurs, so that they have an opportunity to adjust their thermostats, avoid running their dishwasher or doing their laundry, or take other actions to reduce their load during the peak time period. While it is potentially more difficult to contact a large number of residential customers than to contact a smaller number of General Service customers, with today's technologies, it doesn't have to be costly to do this in either case. If CPP customers are contacted using a combination of emails, text messages and "robo-calls" (recordings sent to the customer's telephone), a high percentage of the CPP customers will receive advance notification of the peak period, the per-customer cost would be minimal, and it would be just as practical to contact residential customers as General Service customers.

In justifying the proposed CPP program for General Service customers, Mr. Miessner says that it will "test the potential load reduction during critical hours, customer acceptance, and will assess implementaiton cost issues." Since the CPP proposal is effectively a pilot program, it appears to me to be reasonable to include residential customers in this pilot program. The Company has not offered any evidence suggesting that a CPP approach will be successful with General Service customers but not with residential customers. In both cases, opportunities exist for customers to respond to narrowly focused, timely price signals, and in both cases there is reason to be concerned that only a small number of customers will initially volunteer to try this new pricing approach. By testing it with both General Service and residential customers, the Company would more quickly gain experience with the CPP approach – and it is quite possible that the CPP approach will be more popular with residential customers than with business customers.

Q. Can you now discuss the Company's proposed "Impact Fee"?

A. Yes. According to APS, the Commission has expressed a "desire to have growth contribute a greater share to funding growth..." [Rumolo Direst, p.9] In fact, as described by APS, in Decision No. 70185 "the Commission approved revisions to Schedule 3 that requires new customers to pay for infrastructure investment required to serve them." [Id., p. 10] The Decision also required that proceeds received from customers through Schedule 3 be booked as Contributions in Aid of Construction ("CIAC"). [Id.] APS' proposed impact fee is intended to recover the "annual capital carrying cost" associated with the Schedule 3 CIAC, and "anticipated increases in operations and maintenance expenses that are customer-growth related. [Id., pp. 10-11] The Impact Fee would be charged to all applicants requesting electric service, and would depend on the service entrance size ("SES") that is required to serve the customer. [Id. p. 10]

> On a going forward basis, Schedule 3 will recover a significant portion of the distribution capital cost of growth. What will not be recovered, however, are the carrying cost expense of the tax asset created by

> Schedule 3 CIAC and certain growth-related increases in operating expenses. [Id., p. 12]

The proposed impact fee is based on "the average number of actual and forecast meter sets for the five-year period ending 2012", resulting in an overall average cost per meter set of $2,100 and a typical residential fee of $1,300. [Id., p. 14] The first customer requesting permanent service at a location would pay the impact fee. [Id., p. 15]

Q. What is your response to the Company's proposed Impact Fee?

A. To the extent inflation outstrips the benefits of technological improvements and increased economies of scale, the Company's per-unit costs will tend to increase as more people move to Arizona, and thus it becomes necessary to expand the APS system. As the Commission has recognized, it might be beneficial to develop a rate design which reflects this situation, so that growth more nearly pays for itself. While I see some merit to the Company's impact fee proposal, I do not recommend adopting the proposal as filed. To the extent the Commission is interested in having growth become more nearly self-funding, it should move cautiously, and it should carefully think through the underlying issues before taking action.

If the Commission is interested in adopting an impact fee, it will need to decide what portion of the cost of growth should be recovered through this mechanism. For instance, should it only include distribution related costs, or should it also include production and transmission costs? Should it include the entire additional cost imposed when a new customer joins the system, or only the difference between the current cost of serving a new customer compared to the historical cost of serving existing customers?

Similarly, if the Commission is going to implement an impact fee, it should be phased in carefully, to avoid having an undue impact on customers who are currently constructing a new home or business, or who have already purchased land with the intent of doing so. A carefully-developed approach should ameliorate any adverse impact on the real estate and construction industries, by providing them with ample notice and an opportunity to adapt to the new system, and by helping to ensure that the impact fee is borne by new customers, rather than by the people who construct and sell new buildings. This can be accomplished by announcing the impact fee in advance, by phasing it in over a reasonable period of time, by providing all concerned with ample opportunity to adapt to the new environment, and by structuring the fee as a cost of construction, rather than a cost of occupying the new building.

Q. Can you provide some additional, more specific guidance to the Commission?

A. Yes. First, it would be preferable to apply the impact fee during the construction period, rather than at the end of the construction period, as proposed by APS. This would ensure that the fee is appropriately included in the principal amount of the construction and permanent financing, rather than being treated as an out-of-pocket occupancy expense of the new customer, analogous to the cost of furnishing the building. By including the impact fee in a homeowner's monthly mortgage payments, the impact will be spread over a lengthy period of time, just as if the costs were recovered through the customer's monthly electrical bill.

Second, the impact fee should be designed in a manner that minimizes any adverse impact on the real estate and construction industries. Depending on how the fee is designed and phased-in, it could actually help participants in these industries, by boosting the value of existing, recently constructed buildings, and by providing an incentive for customers to purchase recently constructed existing buildings, as well as buildings that are constructed during the transitional period (prior to the time when the impact fee goes into full effect).

Q. Does this conclude your direct testimony concerning the cost of service and rate design issues, which was prefiled on January 9, 2009?

A. Yes.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

Canada—Department of Communications
Hillsborough County Property Appraiser
Provincial Governments of Canada
Sarasota County Property Appraiser
State of Florida—Department of General Services
United States Department of Justice—Antitrust Division
Utah State Tax Commission

Regulated Firms

Alabama Power Company
Americall LDC, Inc.
BC Rail
CommuniGroup
Florida Association of Concerned Telephone Companies, Inc.
LDDS Communications, Inc.
Louisiana/Mississippi Resellers Association
Madison County Telephone Company
Montana Power Company
Mountain View Telephone Company
Nevada Power Company
Network I, Inc.
North Carolina Long Distance Association
Northern Lights Public Utility
Otter Tail Power Company
Pan-Alberta Gas, Ltd.
Resort Village Utility, Inc.
South Carolina Long Distance Association

Stanton Telephone
Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

Other Private Organizations

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
AVERAGE AND EXCESS DEMAND EXAMPLE

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-15

LINE NO.	Customer Class	Maximum Load (KW)	Load Factor	Average Demand	Load at CP	Class NCP	Excess Demand	Allocated Excess Demand	Average and Excess Demand	Share of Production Costs
1	Class A	50	100%	50	50	50	0	0	50	18.18%
2	Class B	100	50%	50	0	100	50	15	65	23.64%
3	Class C	100	50%	50	75	100	50	15	65	23.64%
4	Class D	200	25%	50	150	200	150	45	95	34.55%
5	Total	450		200	275	450	250	75	275	100.00%

REFERENCE
N/A

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
PRODUCTION PLANT

DOCKET NO. E-01345A-05-08
SCHEDULE BJ-16

LINE NO.	Plant	Originally Constructed	Last Unit Installed	Plant Type	Fuel	Net Name Plate Capacity	Net Gen. (kWh)	Usage Rate	Installed Cost per KW	Installed Cost	Production Expenses	BTU per kWh	Production Expenses per kWh	Category	Installed Cost
1	Palo Verde 1	1986	1988	Nuclear	Uranium	408	3,188,660,166	89.2%	$ 1,528	$ 623,312,615	$ 96,512,677		0.030	Baseload	
2	Palo Verde 3	1986	1988	Nuclear	Uranium	408	2,572,769,974	72.0%	2,488	1,014,927,265	61,804,525		0.024	Baseload	
3	Palo Verde 2	1988	1988	Nuclear	Uranium	409	2,032,246,125	56.7%	2,258	923,455,662	61,457,169		0.030	Baseload	
4	4 Corners 4	1974	1976	Steam	Coal	337	2,375,702,001	80.5%	748	252,089,737	56,055,229	10,130	0.024	Baseload	
5	Cholla 2	1980	1981	Steam	Coal	312	2,157,836,989	79.0%	755	235,477,994	45,579,657	10,470	0.021	Baseload	
6	Cholla 3	1978	1981	Steam	Coal	289	2,136,819,717	84.4%	973	281,201,560	49,276,910	10,396	0.023	Baseload	
7	Navajo 1,2,3	1964	1970	Steam	Coal	254	1,743,431,648	78.4%	573	145,568,767	42,024,177	10,786	0.024	Baseload	
8	4 Corners 5	1963	1970	Steam	Coal	190	1,349,710,429	81.1%	572	108,607,384	33,897,683	10,895	0.025	Baseload	
9	4 Corners 3	1963	1970	Steam	Coal	190	1,290,595,528	77.5%	589	111,953,998	40,142,615	10,756	0.031	Baseload	
10	4 Corners 2	1969	1970	Steam	Coal	123	784,575,583	72.8%	576	70,884,160	17,142,359	9,920	0.022	Baseload	
11	4 Corners 1	1962	1981	Steam	Coal	114	763,194,815	76.4%	944	107,583,682	33,139,293	10,734	0.043	Baseload	
12	Cholla 1	1969	1970	Steam	Coal	122	740,374,477	69.3%	740	90,257,070	15,939,639	9,949	0.022	Baseload	
						3,156	21,135,917,452	76.5%	$ 1,256	$3,965,319,894	$ 552,971,933		0.026		73.74%
13	Redhawk 1	2002	2002	Combined Cycle	Gas	568	2,135,894,000	42.9%	$ 448	$ 254,395,792	$ 158,121,378	7,472	0.074	Midload	
14	Redhawk 2	2002	2002	Combined Cycle	Gas	568	2,065,951,000	41.5%	371	210,663,269	152,815,442	7,546	0.074	Midload	
15	West Phoenix 5	2003	2003	Combined Cycle	Gas	569	1,445,027,000	29.0%	488	277,502,867	111,821,963	7,814	0.077	Midload	
16	West Phoenix 4	2001	2003	Combined Cycle	Gas	136	195,932,000	16.4%	675	91,863,895	18,472,726	8,652	0.094	Midload	
17	West Phoenix 1	1976	2003	Combined Cycle	Gas	132	133,819,130	11.6%	203	26,854,346	14,985,840	10,963	0.112	Midload	
18	West Phoenix 3	1976	2003	Combined Cycle	Gas	132	132,285,000	11.4%	254	33,558,421	13,027,561	9,456	0.098	Midload	
19	West Phoenix 2	1976	2003	Combined Cycle	Gas	132	126,870,450	11.0%	253	33,430,249	14,981,026	9,874	0.118	Midload	
20	Ocotillo 2	1960	1960	Steam	Gas	113	86,751,000	8.8%	240	27,154,548	8,566,084	11,815	0.099	Midload	
21	Ocotillo 1	1960	1960	Steam	Gas	114	81,725,000	8.2%	221	25,211,012	9,393,776	11,798	0.115	Midload	
22	Saguaro 1	1954	1955	Steam	Gas	125	49,811,000	4.5%	197	24,641,160	5,551,946	13,065	0.111	Midload	
23	Saguaro 2	1955	1955	Steam	Gas	125	47,821,000	4.4%	209	26,091,176	4,880,121	12,828	0.102	Midload	
						2,714	6,501,886,580	27.3%	$ 380	$1,031,366,735	$ 512,617,863		0.079		19.18%
24	Sundance	2002	2002	Comb. Turbine	Gas	450	137,346,000	3.5%	$ 610	$ 274,648,128	$ 17,713,378	10,027	0.129	Peaking	
25	Saguaro 3	2002	2002	Comb. Turbine	Gas	78	13,822,000	2.0%	369	28,806,668	2,061,761	13,129	0.149	Peaking	
26	Yucca 3	1973	1974	Comb. Turbine	Gas	56	9,534,000	1.9%	174	9,740,470	1,853,977	17,653	0.194	Peaking	
27	Yucca 1	1971	1974	Comb. Turbine	Gas	20	3,348,000	1.9%	208	4,159,742	846,486	17,182	0.253	Peaking	
28	Yucca 2	1971	1974	Comb. Turbine	Gas	20	2,450,000	1.4%	113	2,266,819	587,595	16,150	0.240	Peaking	
29	Ocotillo 1	1972	1973	Comb. Turbine	Gas	53	5,338,000	1.1%	166	8,822,832	1,043,950	16,568	0.196	Peaking	
30	West Phoenix 1	1972	1973	Comb. Turbine	Gas	53	4,930,000	1.1%	181	9,618,739	925,190	16,618	0.188	Peaking	
31	Ocotillo 2	1973	1973	Comb. Turbine	Gas	53	4,097,000	0.9%	147	7,789,741	850,054	17,028	0.207	Peaking	
32	West Phoenix 2	1973	1973	Comb. Turbine	Gas	53	3,648,000	0.8%	148	7,853,883	717,038	18,063	0.197	Peaking	
33	Saguaro 1	1972	2002	Comb. Turbine	Gas	53	2,214,000	0.5%	172	9,118,715	711,112	16,778	0.321	Peaking	
34	Saguaro 2	1973	2002	Comb. Turbine	Gas	53	1,585,000	0.3%	160	8,476,538	647,599	17,789	0.409	Peaking	
35	Yucca 4	1974	1974	Comb. Turbine	Oil	56	1,106,000	0.2%	127	7,092,696	707,318	19,836	0.640	Peaking	
36	Douglas	1972	1972	Comb. Turbine	Oil	21	135,000	0.1%	107	2,243,795	154,125	18,875	1.142	Peaking	
						1,019	189,553,000	2.1%	$ 374	$ 380,638,766	$ 28,819,583		0.152		7.08%
37	Grand Total					6,889	27,827,357,032	46.1%		$5,377,325,395	$1,094,409,379				100.00%

Source:
2007 FERC FORM 1

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2007
COST OF SERVICE SUMMARY

DOCKET NO. E-01345A-05-0816
SCHEDULE BJ-17

LINE NO.	Customer Class	Average and Excess Demand	Rate of Return	4CP	Rate of Return	Weighted Average 4CP, 1CP	Rate of Return	Recommended Increase
1	**Residential**	**50.65%**	**2.85%**	**52.02%**	**2.68%**	**48.95%**	**3.07%**	
2	E-10 (Residential Service-Old)	2.66%	-0.66%	2.63%	-0.60%	2.53%	-0.41%	Above Average
3	E-12 (Residential Service-New)	13.68%	5.86%	14.07%	5.65%	13.81%	5.78%	Below Average
4	EC-1 (Residential Service with Demand Charge-Old)	1.62%	-2.15%	1.60%	-2.10%	1.56%	-1.97%	Above Average
5	ET-1 & ET-2 (Time of Use)	26.20%	2.68%	27.32%	2.40%	24.71%	3.06%	Average
6	ECT-1R & ECT-2 (Time of Use with Demand Charge)	6.49%	-0.81%	6.40%	-0.73%	6.34%	-0.69%	Above Average
7	**General Service**	**46.19%**	**5.04%**	**45.67%**	**5.14%**	**48.03%**	**4.69%**	
8	E-20 (Church Rate)	0.22%	-0.82%	0.13%	2.05%	0.13%	2.19%	Above Average
9	E-32 (Time of Use)	0.51%	5.93%	0.48%	6.42%	0.64%	3.82%	Average
10	E-30 & E-32 (0-20 kW)	7.46%	3.53%	7.71%	3.31%	5.93%	5.11%	Average
11	E-32 (21-100 kW)	10.71%	5.67%	10.38%	5.94%	9.73%	6.49%	Below Average
12	E-32 (101-400 kW)	10.87%	5.87%	10.37%	6.32%	11.25%	5.55%	Below Average
13	E-32 (401+ kW)	10.44%	6.57%	10.64%	6.37%	12.34%	4.87%	Average
14	E-34 (General Service-Extra Large)	2.85%	3.48%	3.01%	3.00%	3.75%	1.13%	Above Average
15	E-35 (Time of Use-Extra Large)	3.13%	-0.50%	2.94%	0.00%	4.26%	-2.73%	Above Average
16	**Irrigation**	**0.92%**	**6.91%**	**0.55%**	**15.95%**	**0.92%**	**6.97%**	Below Average
17	**Street Lights**	**0.39%**	**-0.03%**	**0.00%**	**2.17%**	**0.27%**	**0.55%**	Above Average
18	**Dusk to Dawn**	**0.08%**	**6.61%**	**0.00%**	**8.06%**	**0.06%**	**7.01%**	Below Average
19	**Total**	**98.23%**	**3.79%**	**98.23%**	**3.79%**	**98.23%**	**3.79%**	

REFERENCE